COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE GREEN RIVER GENERATING STATION AND A SOLAR PHOTOVOLTAIC FACILITY AT THE E.W. BROWN GENERATING STATION	**)))))))))**	**CASE NO. 2014-00002**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY
TO THE ATTORNEY GENERAL'S INITIAL DATA REQUESTS
DATED MARCH 13, 2014

FILED: MARCH 27, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2013.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Director, Corporate Tax and Benefit Plan Compliance for LG&E and KU Services Company, 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.

Gregory J. Meiman

Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett
Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

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

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

(SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

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

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

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

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 1

Witness: Edwin R. Staton

Q-1. Provide a copy of the application, including all testimonies, in Word version.

A-1. On March 5, 2014 an email was sent to the AG Office of Rate Intervention counsel that included Word versions of the Application, Testimonies, and Exhibit DSS-1. The Word versions contained the same information as the PDF versions filed electronically by the Companies in this proceeding.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 2

Witness: David S. Sinclair

Q-2. If not already provided, provide a copy of all Excel spreadsheets, with all formulae and cells intact and unprotected, referenced or contained within the application.

A-2. See the response to PSC 1-22.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 3

Witness: David S. Sinclair

Q-3. Reference the application at page 4. Provide a copy of the Request for Proposals (RFP) that were sent in September 2012.

a. Explain in detail how the 165 potential suppliers were decided.

b. If any potential energy providers were not included as recipients for the RFP, please detail which ones and the reason(s) why each one was not included.

A-3. See attached.

a. The 165 potential suppliers referenced on page 20, line 6 of Mr. Sinclair's testimony were determined from parties that responded to past RFPs, made their interest to respond to an RFP known to the Companies, or were an authorized counter party for power transactions.

b. No known potential energy provider was excluded from receiving the RFP. To ensure that unknown potential energy providers were aware of the RFP it was announced in the electric industry news media, specifically Platts and SNL (a subscription is required to access articles). The RFP was also referenced at the Herald Leader (website below) and The Courier Journal Blog (website below) and at the Companies' website.

http://www.kentucky.com/2012/09/11/2332734/ku-seeking-more-power-generation.html

http://blogs.courier-journal.com/watchdogearth/2012/09/12/lge-and-ku-energy-weighs-phasing-out-two-more-coal-burning-units/

PPL companies

LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
www.lge-ku.com

Charles A. Freibert, Jr.
Director Marketing
T 502-6273673
charlie.freibert@lge-ku.com

September 7, 2012

Subject: Request for Proposals to Sell Capacity and Energy (RFP)

Dear Colleague in Development, Marketing and Trading of Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly the "Companies") are evaluating alternatives means to provide least-cost firm generating capacity and energy to our customers in the future. To this end, the Companies are requesting proposals from parties wishing to sell capacity and energy that will qualify as a Designated Network Resource (DNR) either as an owned asset by the Companies or a Power Purchase Agreement with the Companies. The Companies will consider offers that are reliable, feasible and represent the least-cost means of meeting our customers' capacity and energy needs, including cost for transmission service, transmission upgrades and voltage support. The Seller should make its proposal as comprehensive as possible so that the Companies may make a definitive and final evaluation of the proposal's benefits to its customers without further contact with the Seller. However, the Companies reserve the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Companies' internal evaluation of cost, risk, and value.

This inquiry is not a commitment to purchase and shall not bind the Companies or any subsidiaries of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which Respondent(s), if any, it wishes to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses Respondents incur in connection with preparation of a response to this RFP. The Companies will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Companies at their sole discretion.

1. **<u>Background</u>** - This RFP is being issued in order to evaluate alternative means to provide least-cost firm generating capacity and energy to our customers in the future while meeting all laws and regulations. All alternatives (including any of the Companies' self-build options) will be evaluated in the context of meeting customers' load in a least-cost manner. If the Companies determine that a proposal maybe in the best interest of the Companies' customers, the Companies will enter into negotiations which may lead to the execution of definitive agreements. The Companies will consider all applicable factors including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the purchased power proposal or facility or asset sale; (ii) Seller's creditworthiness; (iii) if applicable, the development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission; or the operating history of Seller's generation facility; (iv) the degree of risk as to the availability of the power in the timeframe required; (v) the anticipated reliability of the power, particularly at times of winter and summer peak; and (vi) all other factors such as the cost of interconnection or transmission that may affect the Companies or their customers. The Companies are committed to implementing the best overall long-term solution for their customers.

2. **<u>Requirements</u>** - The Companies are interested in Power Purchase Agreements ("PPA"), Tolling Agreements ("TA") or Build Own Transfer Agreements ("BOT"), or alternative power supplies (combined "Supply Agreements") for minimum quantities of 1 MW up to a total of 700 MW of firm summer and winter capacity and associated energy per facility or offer. The power being proposed must be generated from a defined source, a specific unit(s) or system that will qualify as a DNR and supply capacity/energy during the peak demand of the Companies' customers (typical Midwest seasonal load characteristics). The delivery of capacity and energy should begin no earlier than January 1, 2015, and later start dates will be considered. The Companies are interested in both short term (1 to 5 years) and long term (10 to 20 years) proposals. The Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple Sellers to meet its needs. A Seller offering power from a resource connected directly to the Companies' transmission system must conform to the Companies' Open Access Transmission Tariff (OATT) and must obtain in a timely manner an Interconnection Agreement for the facility.

3. **<u>Key Terms and Conditions</u>** - The Seller's proposal should include the proposed terms and conditions, which should include, where applicable to the Seller's proposal, among other things:

   3.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, fuel availability, fuel transport, operation and maintenance cost, etc., for at least 150 days after the Proposal Due Date.

   3.2. Any Capacity Payments to the Seller will be based upon guaranteed capacity at the Summer Design Conditions delivered to the Companies' transmission system unless the location of the Seller's facility justifies alternate conditions. Summer Design Conditions shall be the following.

3.2.1. Dry Bulb: 89°F
3.2.2. Mean Coincident Wet Bulb: 78°F

3.3. Seller will guarantee the annual and seasonal availability and describe required maintenance outage schedule.

3.4. Seller should address in their proposal its remedies for failure to meet availability guarantees.

3.5. Seller will be responsible for any and all compliance related cost and fines (environmental, NERC, FERC, etc) incurred due to the non-compliance of the assets designated to supply power to the Companies.

3.6. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

3.7. The Companies termination rights will include, but may not be limited to: (i) failure to obtain all required regulatory approvals, (ii) failure to post or maintain required financial credit requirements, (iii) failure to meet key development and implementation milestones, (iv) failure to meet reliability requirements, and (v) failure to cure a material breach under the Supply Agreement.

4. **Dispatching and Scheduling** (Required Proposal Content) - The Companies prefer flexibility in the utilization of the generation resource being offered by the Seller. The Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time control/dispatch of generation to follow load changes and respond to system frequency changes. The Seller should state its desire and willingness to allow and cooperate with the Companies in establishing real-time control of generation.

5. **Ancillary Services** (Required Proposal Content) - Under a Supply Agreement, the Companies desire to have the unrestricted right to utilize all ancillary services associated with generation being offered by the Seller. The Seller should describe the ancillary service capability of its proposal e.g., black start capability, voltage support, load following, energy imbalance, spinning reserve, and supplemental reserve. The ancillary services that would be available to the Companies should not be limited to those defined in this paragraph. The Companies desire to have the unrestricted rights to any future ancillary services defined by the industry and capable of being provided by the generation capacity being offered. In the case where the Companies purchase only part of the generation capacity from a unit, system or facility, then the Companies desire to have unrestricted rights to ancillary services on a prorated basis.

6. **Pricing** (Required Proposal Content) - The Seller's pricing must be a delivered price to the Companies' transmission system. The Companies will be responsible only for Network Integrated Transmission Service (NITS) on the Companies transmission system. Prices must be firm, representing best and final data and quoted in U.S. dollars. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

    6.1. The Seller's proposal must provide the product and generation characteristics on the attached form. Pricing information can be provided on the form or separately in another format that is appropriate for the offer. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. These attached data forms may be utilized in any filings with regulatory agencies (such as the KPSC) related to this RFP.

7. **Delivery** (Required Proposal Content) - The Companies consider reliable power delivery at the time of the typical summer and winter peak demand of its customers to be of the utmost importance. The delivery point is the Companies' transmission system. Under a Supply Agreement, Sellers would be responsible for providing firm transmission to the Companies' transmission system. The Seller is responsible for all costs associated with transmission interconnections and shall provide all studies and Interconnection Agreements. The Seller is responsible for all transmission reservations, losses and costs including system upgrades up to the delivery point and shall provide all studies and Transmission Reservations/Agreements. All costs associated with interconnections and transmission up to the delivery point should be included in the Seller's pricing where appropriate under current FERC orders and rulings. TranServ International, Inc., 2300 Berkshire Lane North, Minneapolis, Minnesota 55441, is an Independent Transmission Operator that administers the Companies' OATT. Tennessee Valley Authority (TVA) serves as the Companies' Reliability Coordinator (RC). For purposes of the Companies' evaluation of the proposals, the Companies may estimate any transmission costs that are not supported by the appropriate studies including deliverability and the associated voltage support to the Designated Network Load ("DNL") of the Companies. If the Seller has not completed all required transmission studies, it is essential that the following information be provided in order for the Companies to evaluate the proposal:
    - Size of the unit
    - Point of interconnection to the grid
    - Impedance of the generator step-up transformer
    - Transient and sub transient characteristics of the generator

8. **Environmental** - For the sale of generation capacity and energy to the Companies under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the

permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller. The Companies require that Sellers provide the following information for evaluation:

- Unit heat rate, fuel specification, and control technologies employed.
- Emissions rates for NOx, SOx, CO, CO2, PM_{10}, and Hg.
- Copy of air permit or permit application if available.
- Timing and status of all permit applications including air, water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.

9. **Development Status** – Seller shall provide a comprehensive narrative of the status of the development of any generation project intended to be used to meet Seller's obligations to the Companies. Seller's narrative shall include the following.
   9.1. A comprehensive development and construction schedule,
   9.2. A listing of all required permits and governmental approvals and their status,
   9.3. A listing of all required electric interconnection and or transmission agreements and their status,
   9.4. A financing plan, and
   9.5. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.

10. **Other Information Requirements** - Sellers shall provide a complete description of the generation facilities that would be used to fulfill the Seller's obligations to the Companies. The description should include the following:

- Seller's operating experience with similar technology.
- Guaranteed capacity rating and heat rate at Summer Design Conditions of:

Dry Bulb	89	F
Wet Bulb	78	F

- Guaranteed capacity rating and heat rate at winter design conditions of:

Dry Bulb	14	F

- Guaranteed capacity rating and heat rate at average day design conditions

Dry Bulb	57	F
Relative Humidity	60	%

- Guaranteed ramp rate in MWs/minute if applicable.

- Guaranteed annual and seasonal availabilities including EFOR values and planned maintenance schedules.
- Technology employed (combined cycle, pulverized coal, CFB, super-critical, etc.)
- Plant location along with proof or status of ownership or control of site.
- Zoning status of plant site.
- If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.
- Status of engineering and design work.
- Key project participants including owners, operators, engineer/contractors, fuel suppliers

The Seller should also provide any additional information the Seller deems necessary or useful to the Companies in making a definitive and final evaluation of the benefits of the Seller's proposal without further interaction between the Companies and Seller.

11. **Financial Capability** - Should the Companies elect to enter into an agreement with a Seller who fails to meet its obligations at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, the Sellers will be required to demonstrate, in a manner acceptable to the Companies, the Seller's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of the Supply Agreement. Under no circumstances, should the Companies' customers be exposed to increased costs relative to the cost defined in an agreement between the Seller and the Companies.

    11.1. At all times, the Seller will be required to maintain an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    11.2. Upon execution of the Supply Agreement, Sellers will be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the Seller. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. This amount shall take into account the cost of replacement energy and associated environmental cost with the production of replacement energy and any byproducts of such replacement energy. If the Companies draw down the LOC amount at any time, the Seller must replace the LOC to the original value within five days.

12. **Alternate Power Supplies** - Alternate power supply arrangements may include the acquisition of generation assets, existing generation facilities, projects under development, system firm products, or other power supply arrangements that meet the Companies' requirements described in this RFP. The Seller must make all transmission arrangements for the delivery of alternate power supply arrangements to

the delivery point and include the cost for transmission in the pricing. Sellers interested in proposing alternative power supplies must provide all information specified in this document and applicable to the alternate power supply needed for the Companies to fully evaluate the proposal. Those Sellers proposing the sale of generation facilities should include the following:

- Complete description of the facilities included in the sale.
- Firm offer price
- Term sheet which identifies key terms and conditions
- Latest condition report
- Projected operating data including output, heat rate, and forced outage rate as appropriate
- Projected operating expenses and capital expenditures
- For existing facilities, provide historical operating data, operating expenses, and capital expenditures for a minimum of the latest five years or since the start of commercial operation if in commercial operation for less than five years.

13. **RFP Schedule** - All proposals must be complete in all material respects and be received no later than 4 p.m. EDT on Friday, November 2, 2012. Email proposals must be followed up with a signed original within two business days.

RFP Issued	Friday, September 7, 2012
Proposals Due	Friday, November 2, 2012
Evaluation Completed	Friday, March 15, 2013

Proposals will not be viewed until 4 p.m. EDT on Friday, November 2, 2012. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

14. Treatment of Proposals

14.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. The Companies also reserve the right to modify the RFP or request further information, as necessary, to complete its evaluation of the proposals received.

14.2. Sellers who submit proposals do so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of capacity and/or energy for any reason. Sellers are responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

15. **Confidentiality** - As regulated utilities, it is expected that the Companies will be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is more likely to be granted if limited amounts of information are designated as confidential rather than large portions of the proposal. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to this information. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the Seller's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

16. **Contacts** - All correspondence should be directed to:

Charles A. Freibert, Jr.
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

E-mail: charlie.freibert@lge-ku.com
Phone: 502-627-3673

In closing, I look forward to your response by 4 p.m. EDT on Friday, November 2, 2012, and the possibility of doing business to meet the Companies' future power needs. Your interest in this request is greatly appreciated. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact Donna LaFollette at 502-627-4765.

Sincerely,

Charles A. Freibert, Jr.

Charles A. Freibert, Jr.

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller ____

Product and Generation Characteristics:
Proposal Description____
____
____
____
Generation Source Description ____
Transmission Interconnection Point of the Source ___________________________________
Point of interconnection to the grid ____
Fuel Commodity Price (if applicable) _____________________
Firm Fuel Transport Price (if applicable)
Start Date and Term of Contract ____
Summer Firm Capacity Amount ________ MW
Summer Maximum Dispatch Capacity Amount (if applicable) ________MW
Summer Minimum Dispatch Capacity Amount (if applicable) ________ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) ________Btu/kwh
Winter Firm Capacity Amount ________ MW
Winter Maximum Dispatch Capacity Amount (if applicable) ________MW
Winter Minimum Dispatch Capacity Amount (if applicable) ________MW
Output in 10 minutes ________MW
Guaranteed Ramp capability ________MW/minute (if applicable)
Start-up time to minimum capability ____________________________________
Start-up time to maximum capability ____________________________________
Minimum run time ____________________________
Minimum down time __________________________
Constraints on production time (if applicable) ______________________________
Forced Outage Rate _________________%
Guaranteed Availability ____
Planned Outage Schedule ____

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year or Index_________________
Fixed O&M_______________($/MWH or $/MW-yr)
Year of Fixed O&M Price Quote ____
Fixed O&M Price Excalation/yr or Index_________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term
    a. Variable O&M ___________ ($/MWh)
    b. Guaranteed Heat Rate _______ (Btu/kwh)
    c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 4

Witness: Edwin R. Staton

Q-4. Reference the application at page 5 at paragraph numbered 5. Explain in detail what is meant by the statement that "it is not anticipated that Green River NGCC will compete with any other public utilities, corporations or persons."

A-4. 807 KAR 5:001, Section 15(2)(c) requires an applicant in a case seeking a certificate of public convenience and necessity to identify public utilities, corporations, or persons with whom the proposed construction is likely to compete. The statement addresses that requirement.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 5

Witness: John N. Voyles, Jr.

Q-5. Reference the application at page 6. Explain in detail how the engineering firm was selected to "perform engineering services, optimize design for the Companies' needs, support environmental permitting, and to assist the Companies in their procurement practices"

a. Was an RFP process used? If not, why not? If yes, provide a copy of the RFP.

b. Is the engineering firm associated in any way with either of the companies? If so: (i) which one(s)?; and (ii) describe in detail.

A-5.

a. The Companies developed a bid list of four qualified and interested engineering firms. The RFP attached was sent to Burns & McDonnell, HDR, CH2MHill and Sargent & Lundy on March 7, 2013.

b. No, none of the engineering firms are affiliates of the Companies.

Exhibit 1

E.W. Brown Generating Station Natural Gas Combined Cycle Project
Owner's Engineer Services
Statement of Work

I. **Background:** *LG&E and KU Services Company* (Company) is seeking the support of an Owner's Engineer (OE) to support development, project management, permitting, specification, procurement, and engineering for a brown field natural gas combined cycle (NGCC) plant at the E.W. Brown Generating Station in Burgin, Kentucky. The overall NGCC project is proposed with a January 2018 commercial operation date.

II. **Firm Scope Tasks**

A. Contracting strategy document – the OE, with input from Company, is to assist in developing a transparent contracting strategy document (EPC vs. EpC, full power island vs. individual equipment procurement, owner furnished equipment strategy, etc.) that is defensible under public scrutiny and the Certificate for Convenience and Necessity (CCN) processes.

B. Specification development for Major Equipment and EPC – the OE, with input from Company, is to develop all technical specifications encompassing all applicable codes and standards required to bid Major Equipment (combustion turbine, steam turbine, heat recovery steam generator, and related materials) and to bid Engineering Procurement and Construction of the project. Include a review and analysis of applicable EPRI reports regarding design and operation of NGCC technologies for inclusion to the technical specifications. The OE will develop Bid Instructions, Technical and Commercial Bata Tables, Performance Guarantees and Test Protocols, Submittal Requirements, and minor commercial exhibits for the procurement process.

C. Labor Market Analysis – the OE is to perform an analysis of the current labor market surrounding the Job Site to determine the availability of competent labor resources and the associated rates, incentives, and per diem.

D. Vendor/EPC Qualification – the OE, with input from Company, is to develop and manage a transparent, well defined, and well documented qualification process that is defensible under public scrutiny and the CCN process. The qualification process is to include pre-qualification questionnaires, analysis, vendor meetings and a final documentation that describes the process, interprets the data, and defines bid lists.

E. Review existing plant feasibility study, refine and update the conceptual design as necessary.

F. Prepare an AACE Class IV cost estimate for the conceptual design developed in task E, based on the labor strategy developed in C and contracting strategy developed in A.

G. Develop a list, with direct input from Company, of Acceptable Equipment Suppliers. List should include but not be limited to transformers, switch gear, control systems, aux. boilers, fuel gas heaters, boiler feed pumps, cooling towers, instruments, controls and other equipment.

H. Market Place Exploration – the OE is to perform a detailed exploration of the current market place for NGCC equipment and processes in order for Company to make well informed decisions concerning all aspects of the Project.

I. Project Management - OE is to provide weekly: status update, action items log, phone conference, schedule update, and labor report (detailed by employee). Submit monthly progress reports during all phases of the project. The reports shall describe the progress of work completed, planned work for the next month, the engineering cost status, the engineering schedule, and other metrics as required. Maintain a complete auditable set of files as project record for the firm scope tasks. OE is to provide monthly accruals on the third day before the last business day of the month.

III. Non-Firm Scope Tasks –

A. Permitting Support – Company will take the lead in permitting efforts; the OE is to assist Company and provide third party support with tasks arising from the process of obtaining all applicable permits for the work including air, and water permits].
B. CCN Filing Support – Company will take the lead in CCN documentation preparation; the OE is to support Company with any tasks that arise during the CCN filing process. Conceptual Studies – the OE shall perform conceptual studies as needed by Company to determine emerging technologies, equipment, or Project impacts.
C. Conceptual Studies – OE is to provide conceptual studies as tasked by Company
D. Technology Review – the OE sis to stay abreast of market place shifts in NGCC technology and provide timely education of technologies to Company. The technology reviews shall include but not be limited to commercial readiness, cost estimate, auxiliary power requirements, maintenance requirements, and areas of concern.
E. Manage, Review, and Analysis of Equipment and EPC Bids – the OE is to assist Company with responses to bid exceptions and clarifications as well as the technical review and analysis of Major Equipment and EPC bids. The OE is to ensure that all bid information treated equally and confidentially to ensure an unbiased review process. OE is to assist in final conformance of the final Equipment and EPC agreement documents.
F. Technical Review during Open Book Period, if required – the OE is to assist Company in the technical review bids during the Open Book Period if required during the project.
G. Document/drawing review post Supplier/EPC NTP – after Major Equipment and EPC Contract award and notice to proceed (NTP) the OE is to provide assistance to Company in the review of all project documents and drawings received from the EPC Contractor its Suppliers or sub-contractors. The OE also is to create a document management system/process to ensure that all documents and drawings are properly reviewed by the OE and Company and that corrections are made within the review period determined in the contract language.
H. Engineering Function for Non-EPC Scope – the OE is to be responsible for engineering functions and balance of plant activities as tasked by Company for scopes not included in the EPC Scope of Work.
I. Other tasks as assigned.

Company makes no representation with respect to the release or quantity of work in the under the non-firm scopes listed above. These scopes will be released solely at Company's discretion and Company reserves the right to bid any of these scope tasks during the course of the project.

IV. Schedule

A. Company's development schedule is provided in Attachment A.

V. SOW Deliverables

A. Kick-off Meeting
B. Project Meeting and Progress Reports – OE is to provide weekly: status update, action items log, phone conference, and labor report (detailed by employee). OE is to provide monthly accruals on the third day before the last business day of the month.
C. Document Management **-** OE shall maintain thorough and auditable document management files for the Work.
D. Draft & Final Reports **–** OE shall deliver a draft report containing results from section II defined herein and shall submit final reports within seven (7) days of receiving comments from Company. Final Report submittal is three (3) hard copies and electronic media (compact disc).

VI. RFP Deliverables

A. Proposal Index
B. Summary of Proposal
C. Project organizational structure – including location and description of where work is to be performed.
D. Resumes of Project manager and key staff working on the Project highlighting recent relevant experience
E. Table of experience, projects of similar nature that validate Contractor's data base
F. Customer references and contact information
G. Fee structure and Rates
H. T&M NTE Manhours by Resource Classification by Task and cost for each task defined in section II above and loaded into the provided MS Excel Worksheet
I. Annual budgetary estimate for tasks defined in section III above
J. Master Contract
K. Proposal Clarifications & Exceptions – see Bid Clarification Spreadsheet
L. Schedule for completing tasks defined in section II above with respect to Attachment A.
M. Draft weekly report & Time Sheets
N. List of any Company Supplied Items Requirements (items OE needs from Company to perform work).
O. Description of relationship, if any, with manufacturers of NGCC technologies/equipment

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 6

Witness: John N. Voyles, Jr.

Q-6. Provide the following information regarding the engineering firm:

a. Names and qualifications for each individual providing services to the Companies;

b. Total amount paid to date to the firm;

c. Total projected amount to be paid to the firm; and

d. If possible, provide the amount to be paid, or that has been paid, to the firm broken down by type of service provided or will be provided.

A-6. The Companies object to this request on the grounds that the information it seeks is not relevant to the issues in this proceeding. Notwithstanding this objection, the Companies provide the following:

a. The attached provides the names and qualifications of the principal HDR team members.

b. Through February 28, 2014 HDR has been paid $486,087.

c. The HDR contract is valued at $2.2 million.

d. The amount to be paid for development support is estimated to be $0.9 million, of which $0.486 million has been paid. Construction support is estimated to be $1.3 million. No payments have been made for construction support services.

PROJECT TEAM QUALIFICATIONS

HDR understands the importance of this project to LG&E and KU Services Company (LG&E/KU) and offers a highly qualified and experienced team of professionals who have recent experience supporting natural gas combined cycle power projects and have worked together as a team.

Our team possesses significant experience in combined cycle generating plant development, permitting, engineering, equipment procurement, construction and start-up/commissioning, from both an Owner's and EPC contractor's perspective. This experience combined with the team's Owner's Engineer experience, provides a solid base from which expertise can be assigned to specific tasks, as well as a solid foundation from which to support important business decisions, which are an important facet of an Owner's Engineer responsibility.

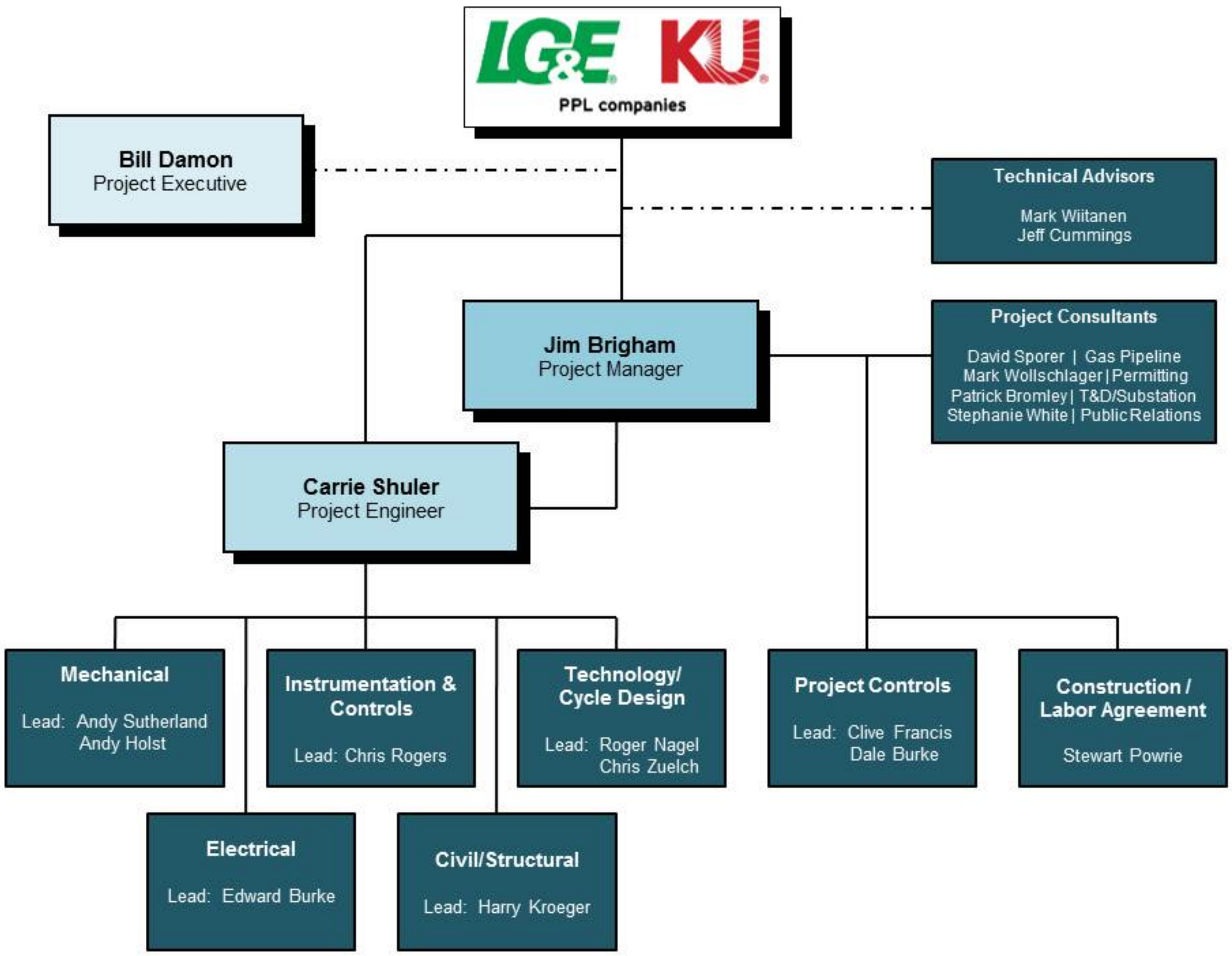
Project Team Highlights

- Combined team experience totaling over 400 years
- Project consultants' experience in excess of 130 years
- Extensive strategic consulting /Owner's Engineer experience
- Experience working together as a team
- Familiarity with LG&E/KU previous projects
- Strong resume of applicable experience: combined cycle combustion turbines, Owner's engineer
- Access within HDR to resources outside power generation disciplines

Further, this project team understands the demands of developing and managing a program of this magnitude. The extensive combustion turbine and program development/Owner's Engineer experience of the team provides a significant advantage for crafting project execution plans, strategies and schedules, developing cost estimates and implementation schedules, preparing siting documents, technical and procurement specifications; and coordinating permitting applications, as well as supporting LG&E/KU with regulatory and/or public relations issues throughout the project. As with any project, a strong, knowledgeable project team is the key to success.

For each area, we have identified top performers in our technical resource pool to provide the critical services required to support LG&E/KU to bring this project in on time and within budget.

The organization chart below displays our proposed organization strategy for this project. Following is a brief introduction to the team members. Complete resumes are included at the end of this section.



Project Executive – Bill Damon is a Registered Professional Engineer in six states and has over 34 years of experience including strategic consulting and project management for power project development. He has extensive experience serving in an Owner's Engineer role for major power projects in national and international locations. Mr. Damon managed OE and development services for natural gas and coal-fired power projects from execution strategies to commercial operation for major clients such as ALCOA, We Energies, International Power and GE-EFS. He is currently serving as Executive Sponsor for OE services for Edison Mission Energy's Walnut Creek Energy Plant, including development of a Request for Proposal for EPC services for a 500 MW simple cycle installation. In addition, he has served as Principal in Charge for OE/Strategic Consulting, providing oversight for We Energies Power the Future Program, including 1100 MW of combined cycle capacity at the Port Washington Generating Station, and as Executive Sponsor for co-developing asset-based energy projects involving combustion turbine combined cycle, distributed generation and CFB technologies for ALCO World Alumina. Mr. Damon has also served as Principal in Charge and Executive Sponsor for projects at LG&E, including OE services for Trimble County, Unit 2; New Base Load Unit project, and generation technology option studies.

***Technical Advisor* –** Mark Wiitanen will serve as a Technical Advisor. Mr. Wiitanen has over 26 years of experience in power generation design and consulting engineering. He has a broad based background of project design and has held lead positions involving peaking, combined cycle and CHP natural gas fired power plants in EPC and OE roles. Mark served as Project Manager for the Feasibility Study portion of the Cane Run NGCC project in addition to the NBU NGCC conceptual design assignment for LG&E/KU. Mark also served as the Project Engineer for the Trimble County Unit 2 Project EPC Contractor Pre-Qualification process development and evaluation. His EPC project experience has included capital serving as Lead Electrical Engineer for Sempra Energy's Mesquite Generating Station, a 1250 MW, 4x2 combined cycle plant, the Kissimmee Utility Authority's Cane Island Park Unit 3 250 MW 1x1 combined cycle unit and the 180 MW simple cycle DePere Energy Center.

Technical Advisor - Jeffrey Cummings will also serve as a technical resource. Mr. Cummings has over 25 years of professional mechanical engineering experience in power generation facilities that encompasses coal, oil, gas and renewable projects, from 10 MW to 750 MW. He is one of only 16 people to receive certification as a ENVISION Sustainable Professional (ENV SP). He is the only one certified in Power. He has provided Owner's Engineer services for combustion turbine projects to many clients such as Calpine, Rolls-Royce Power Ventures, Indeck, Mitsui, and others. His most recent OE assignment is for the Walnut Creek Energy Park consisting of five GE LMS 100 units located in Los Angeles County, California. Mr. Cummings also served as Project Development Manager for several years providing development and permitting support to client projects based on Alstom gas turbine technology. His experience providing AE design services entails being the lead mechanical engineer for General Electric's 500 MW Baglan Bay 9H CC project located in Cardiff, Wales, U.K.; PSI Energy's 165 MW Wabash River Repowering IGCC; Calpine's 500 MW Southpoint CC; and Alcoa's 130 MW CC cogeneration plant located in Jamaica. Mr. Cummings has assisted many clients in combustion turbine, steam turbine, and HRSG procurements and is experienced with the evaluation and technical negotiations associated with Owner furnished equipment projects.

***Project Manager* –** Jim Brigham will serve as the Project Manager. Mr. Brigham has over 22 years of experience in power generation design implementation for utility, industrial, institutional and non-regulated utility power markets including numerous simple cycle and combined cycle combustion turbine projects. His projects range in size from 6 MW to 1,250 MW including design, Owner's Engineer services, and engineer, procure, and construct projects. Mr. Brigham also has significant LG&E/KU experience including project manager for the recently completed Mill Creek Limestone System Engineering, Procurement Support and Construction Management project. Mr. Brighams combined cycle experience includes serving as Engineering Manager supporting TransCanada's initial design and development of a 2x1 advanced G-class combined cycle facility. He has also served as Lead Instrumentation and Control Engineer for several combined cycle design projects including the 1x1 GE7FA 320 MW Burbank Water & Power Magnolia Power Plant, and the 2 x 1 500 MW Seminole Electric Payne Creek Generating Station. In the capacity of Owner's Engineer, Mr. Brigham has recently served as Project Manager for Edison Mission Energy Walnut Creek Energy Center a 500 MW simple cycle, LMS100 generation project in the City of Industry, CA. As Project Manager, Mr. Brigham will be the primary contact between LG&E/KU and HDR.

Project Engineer **–** Carrie Shuler will serve as the Project Engineer. Ms. Shuler has over 20 years of experience in power generation design and consulting engineering. She has a broad based background of project design and has held engineering lead positions involving peaking, combined cycle, and coal fired power plants in EPC and OE roles. Carrie served as Project Engineer for the detailed design of the Mill Creek Station Limestone Grinding System Expansion project for LG&E/KU. Her EPC project experience has included serving as Lead Mechanical Engineer for the AQCS systems for the City of Springfield, Illinois, City Water Light & Power's Dallman Unit 4 Generating Station, a 200 MW coal fired power plant, and as Mechanical Engineer for Seminole Electric Cooperative Inc.'s Payne Creek Generating Station 100 MW 2x1 combined cycle unit and MTP Cogeneration Company, Ltd.'s COCO – Phase III 2x230 MW coal fired hybrid steam electric generating units. Her OE experience has included serving as Project Engineer and Lead Mechanical Engineer for Edison Mission Energy's 5x100 MW simple cycle peaking units Walnut Creek Energy Center and performing detailed design for Ameren/UE's Venice Unit 5 simple cycle unit.

Mechanical Engineering **–** Andy Sutherland will serve as Lead Mechanical Engineer, supported by Andy Holst. Mr. Sutherland has over 14 years of professional mechanical engineering experience in power generation facilities that encompasses coal, oil, gas and renewable projects, from 5 MW to 900 MW. He has provided Owner's Engineer services for combustion turbine projects to many clients such as We Energies, Trans-Canada, Edison Mission Energy, and others. He has recently worked in an OE roll for the Walnut Creek Energy Park consisting of five GE LMS 100 units located in Los Angeles County, California. Mr. Sutherland served as the lead mechanical engineer for Michigan State University's TB Simon Unit 5 &6 cogeneration plant expansion. He has also been lead mechanical engineer for a 2x501G turbine project which was suspended in design. Other design experience includes boiler and turbine installations for a variety of utility and industrial clients. Mr. Sutherland has assisted many clients in combustion turbine, steam turbine, and HRSG procurements and is experienced with the evaluation and technical negotiations associated with Owner furnished equipment projects.

Andy Holst is a project development engineer in HDR's Power Generation group. Mr. Holst's project works has entailed thermal cycle design for combustion turbine, combined cycle, and conventional steam power plants, feasibility studies, economic analyses, and permitting support.

His professional background also includes design, testing, and review of air quality control systems as well as experience specifically with the installation of selective catalytic reduction (SCR) systems and flue gas desulphurization (FGD) systems.

***Electrical Engineering* –** Edward Burke will serve as Lead Electrical Engineer, supported by Adam Gutchak. Mr. Burke has over 42 years of electrical engineering power system experience. Project work includes new and retrofit combustion cycle and coal-fired plants. He recently served as Lead Electrical Engineer for a new, nominal 970 MW combined cycle facility under development in Oakville, Ontario; PEC-Tech Limited's Xiamen combined Cycle Power Station; and Senior Electrical Engineer on Los Angles Department of Water & Power's combined cycle repowering project at Haynes Generating Station; Calpine's 600 MW combined cycle Columbia Energy Center; and Pinnacle West Energy's Redhawk 2 unit 600 MW combined cycle Redhawk Generating Station.

***Instrumentation & Controls* –** Chris Rogers will serve as Lead Instrumentation & Controls Lead. Mr. Rogers has over 16 years of instrumentation and control engineering experience. His recently served as Lead I&C Engineer for a new, nominal 970 MW combined cycle facility located in Oakville, Ontario. Other relevant project experience includes project I&C engineer on the City of Burbank's combined cycle Magnolia Power Project, project I&C Owner's Engineer for We Energies' combined cycle Port Washington and coal fired Elm Road stations, project I&C engineer for Pluspetrol Energy's combined cycle San Miguel de Tucuman generating plant, lead I&C engineer for IPL/AES's simple cycle generating plant, lead I&C engineer for LG&E / Progress Energy's simple cycle Tiger Creek and Trimble County generating plants, and project I&C engineer for Consumer Energy's simple cycle Kalamazoo River generating station.

***Civil/Structural Engineering* –** Harry Kroeger will serve as Lead Civil/Structural Engineer. Mr. Kroeger has over 43 years experience in engineering design and project management for power projects. Mr. Kroeger provided Owner's Engineering services for E.ON's Trimble County Unit 2 Power Plant. In addition, Mr. Kroeger provided project management and structural engineering services for LG&E's upgrade of the coal handing system at the Trimble County Power Plant. This upgrade work included fuel blending, dust control, wet suppression, wet extraction, dustless transfer chutes, wash down piping, explosion vents and drain systems for coal handling systems. Mr. Kroeger also provided Owner's Engineering services on PPL's University Park 585 MW, natural gas-fired, simple-cycle power plant located in an industrial park in University Park, Illinois.

***Technology/Cycle Design* –** Roger Nagel will serve as the lead for technology assessment/cycle design, supported by Chris Zuelch. Mr. Nagel has over 18 years of experience in the design and development of power generation facilities. He has supported the development and construction of domestic and international combustion turbine and combined cycle projects as an EPC Contractor, Owner's Engineer, and as an Original Equipment Manufacturer. Recent projects include serving as the Project Manager for Owner's Engineering Services for the 1,100 MW, 4x2 GE 7FA, Port Washington combined cycle project for We Energies and the 500 MW, 5 x LMS100 Walnut Creek project for Edison Mission Energy. Mr. Nagel has supported numerous E.ON/LG&E initiatives including, but not limited to, the New Build Unit development, natural gas combined cycle feasibility analysis, technology assessments, IRP development activities, and landfill gas opportunities assessment and reference plant design.

Chris Zuelch will serve as support for technology assessment/cycle design. Mr. Zuelch has over eleven years of professional mechanical engineering experience in the design of power generation facilities. His experience encompasses coal, oil, gas and renewable projects, from 10 MW to 1000 MW. He has worked on multiple combustion turbine projects providing design, Owner's Engineering, and project development services. He recently served as a Lead Mechanical Engineer for a new, nominal 970 MW combined cycle facility under development in Oakville, Ontario, providing plant cycle development, permitting support, and management of the combustion turbine contract. Other recent relevant project experience includes Magnolia Power Project, a 310 MW 1 x 1 GE 7FA combined cycle unit; Port Washington, a two block 2 x 1 GE 7FA combined cycle plant; Jamalco, a 2 unit Pratt and Whitney FT8-3 TwinPack combined cycle project; and Bradford Generating Station, a 4 x GE LMS100 simple cycle power project. Mr. Zuelch has also most recently provided project support to LG&E for the Cane Run Combined Cycle Station development and recently supported startup and performance testing for NV Energy's Clark Station Power Plant, which consists of twelve Pratt and Whitney simple cycle combustion turbines.

Project Controls - Clive Francis will be responsible for providing cost estimates and project schedules, supported by Dale Burke. Mr. Francis has over 43 years of experience and is a Certified Cost Consultant. He is responsible for Project Controls including cost and schedule estimating and cost management for power projects at HDR's Ann Arbor, Michigan office. His background includes cost and scheduling support and project controls, with responsibility for development of conceptual level capital cost estimates, earned value analysis, progress performance, cash flows, forecasts, trend reports, project schedule plus updates and analyses. He has been the project controls lead on 10 separate combined and simple cycle projects. These include Sempra Energy Mesquite 4x2 combined cycle, EON US Tiger Creek Units 1-4 and Trimble County 1-4, PG&E Gateway Generating 2x1 Combined Cycle, Seminole Electric Payne Creek 2x1 Combined Cycle plus projects in South America.

Dale Burke will provide support in the area of project cost estimating and scheduling. Mr. Burke has over thirty-five years of experience in estimating, budgeting, construction submittal review, and scheduling for various commercial and power generation projects. He is currently responsible for capital cost estimates for a variety of power generation projects. These include biomass generating facilities, combined cycle, simple cycle, super critical coal, and photovoltaic power generation facilities. He is also responsible for development of detailed comparative estimates for several clients.

Construction Consultant - Stewart Powrie has over 44 years of industry experience as a site manager, project engineer, field engineer for fossil fueled facilities. His experience base includes site project planning, field installation planning, design of rigging for heavy lifts, preparing work instructions for equipment installation, providing competent person inspections and field surveys as well as technical support. Mr. Powrie is a Registered Professional Engineer. He has served as Engineer for Construction Services providing constructability review and comment. He also served as Project Engineer for the Capital District Energy Center project, a 56 MW cogeneration project located in Hartford, Connecticut; CMS's Livingston 4 x 17 MW gas-fired peaking plant located in Gaylord, Michigan; and the LS Power/Westinghouse Cottage Grove 250 MW combined cycle plant. His most recent OE assignment was estimating assistance for the Walnut Creek Energy Park consisting of five GE LMS 100 units located in Los Angeles County, California.

Project Consultants **–** On the organization chart we have identified several individuals who may provide services for the project, if such services are deemed to add value to LG&E/KU. These consultants would be available to assist the HDR project team and LG&E/KU in their respective areas of expertise. Complete resumes for these individuals are included at the end of this section.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 7

Witness: Edwin R. Staton

Q-7. Reference the application at page 7. Provide a copy of the Companies' Power Supply Agreement dated October 9, 1997.

A-7. See attached.

POWER SUPPLY SYSTEM AGREEMENT

Between

Louisville Gas and Electric Company

and

Kentucky Utilities Company

October 9, 1997

POWER SUPPLY SYSTEM AGREEMENT

TABLE OF CONTENTS

SCHEDULES

POWER SUPPLY SYSTEM AGREEMENT

Between

Louisville Gas and Electric Company

and

Kentucky Utilities Company

THIS POWER SUPPLY SYSTEM AGREEMENT, hereinafter called "Agreement," is made and entered into as of the 4th day of May, 1998 by and between Louisville Gas and Electric Company ("LG&E"), and Kentucky Utilities Company ("KU"), hereinafter separately referred to as "Company" and jointly as "Companies."

WHEREAS, LG&E and KU are the owners and operators of interconnected electric generation, transmission, and distribution facilities with which they are engaged in the business of generating, transmitting, and selling electric Capacity and Energy to the general public, to other entities, and to other electric utilities; and

WHEREAS, LG&E's holding company parent, LG&E Energy Corp. ("LEC"), and KU's holding company parent, KU Energy Corporation ("KUC"), have agreed to a merger, pursuant to which KU will become a wholly-owned subsidiary of LEC;

WHEREAS, LG&E and KU can achieve economic benefits for their customers through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their electric supply facilities;

NOW, THEREFORE, the Companies mutually agree as follows:

ARTICLE I

TERM OF AGREEMENT

1.1 Effective Date

This Agreement shall become effective upon the consummation of the merger described in the Agreement and Plan of Merger of LEC and KUC dated May 20, 1997 or such later date as is established by the Federal Energy Regulatory Commission. This Agreement shall continue in force and effect for a period of five (5) Years from the effective date hereinabove described, and continue from Year to Year thereafter until terminated by either Company.

1.2 Periodic Review

This Agreement will be reviewed periodically by the Operating Committee, as defined herein, to determine whether revisions are necessary to meet changing conditions. In the event that revisions are made by the Companies pursuant to Section 10.8, and after requisite approval or acceptance for filing by the appropriate regulatory authorities, the Operating Committee will thereafter, for the purpose of ready reference to a single document, prepare for distribution to the Companies an amended document reflecting all changes in and additions to this Agreement with notations thereon of the date amended.

ARTICLE II

DEFINITIONS

For purposes of this Agreement, the following definitions shall apply:

2.1 Agreement shall mean this Agreement including all attachments and schedules applying thereto and any amendments made hereafter.

2.2 Ancillary Services shall mean those services that are necessary to support the transmission of Capacity and Energy from resources to loads while maintaining reliable operation of the Companies' Transmission System in accordance with Good Utility Practice.

2.3 Capacity shall be expressed in megawatts (MW).

2.4 Company Demand shall mean the demand in megawatts of all retail and wholesale power customers on whose behalf the Company, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its power supply system to meet the reliable electric needs of such customers, integrated over a period of one Hour, plus the losses incidental to that service.

2.5 Company Load Responsibility shall be as follows:

(a) Company Peak Demand; less

(b) Interruptible load including direct load control included in (a) above; plus

(c) The contractual amount of sales and exchanges including applicable reserves during the period to other systems; less

(d) The contractual amount of purchases and exchanges including applicable reserves during the period from other systems.

2.6 Company Operating Capability shall mean the dependable net Capacity in megawatts of Generating Units of a Company carrying load or ready to take load plus firm purchases and exchanges acquired by such Company.

2.7 Company Peak Demand for a period shall be the highest Company Demand for any Hour during the period.

2.8 Economic Dispatch shall mean the distribution of total energy requirements among Power Supply Resources for System economic efficiency with due consideration of incremental generating costs, incremental transmission losses, and System security.

2.9 Energy shall be expressed in megawatt-hours (MWH).

2.10 Generating Unit shall mean an electric generator, together with its prime mover and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of electric Capacity and Energy.

2.11 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

2.12 Hour shall mean a clock-hour.

2.13 Incremental Energy Cost shall mean the Variable Cost which a selling Company incurs in order to supply the next unit of Energy.

2.14 Internal Economy Energy shall mean the Energy supplied and sold by one Company to another Company to enable the purchasing Company to meet a portion of its Own Load at less cost than from its other Power Supply Resources.

2.15 Joint Unit shall mean any Generating Unit jointly owned, if any, by the Companies.

2.16 Margin for a given period shall mean the sum of the amounts developed in accordance with Section 2.17.

2.17 Margin on Energy Sales shall mean the difference between: (1) the revenue from off-system Energy sales and (2) the selling Company's Incremental Energy Cost incurred in making such sales.

2.18 Month shall mean a calendar month consisting of the applicable 24-Hour periods as measured by Eastern Standard Time as required by the appropriate reliability region.

2.19 Open Access Transmission Tariff shall mean the Open Access Transmission Tariff filed with the Federal Energy Regulatory Commission on behalf of the Companies on a combined basis, as amended from time to time.

2.20 Operating Committee shall mean the organization established pursuant to Section 4.1 whose duties are more fully set forth herein.

2.21 Own Load shall mean Energy required to meet Company Demand plus Energy associated with sales or exchanges with reserves less Energy associated with purchases or exchanges with reserves.

2.22 Power Supply Control Center shall mean a center operated by the Companies for the optimal utilization of both Companies' Power Supply Resources for the supply of Capacity and Energy.

2.23 Power Supply Resources shall mean all Energy and Capacity supply resources available to a Company.

2.24 Pre-Merger Off-System Capacity Sales shall mean that certain letter agreement dated July 31, 1992 between LG&E and Indiana Municipal Power Agency ("IMPA") pertaining to the sale of limited term power; that certain Letter Agreement Between LG&E and East Kentucky Power Corporation ("EKPC"), dated October 27, 1994, pertaining to the sale of power to EKPC for Gallatin Steel facilities in Gallatin, Kentucky; and any other agreement for off-System capacity sales as may be entered into by either Company prior to the effective date of the merger.

2.25 System shall mean the coordinated electric generation facilities of the Companies.

2.26 System Demand shall mean the sum in megawatts of both Company's clock-hour Demand.

2.27 Transmission System shall be the facilities owned, controlled or operated by the Companies that are used to provide transmission service under the Open Access Transmission Tariff.

2.28 Variable Cost shall be a Company's incremental generation or purchased Energy cost.

2.29 Year shall be a calendar year.

ARTICLE III

OBJECTIVES

3.1 Purpose

The purpose of this Agreement is to provide the contractual basis for the coordinated planning, construction, operation and maintenance of the System to achieve optimal economies, consistent with reliable electric service and environmental requirements.

ARTICLE IV

OPERATING COMMITTEE

4.1 Operating Committee

The Operating Committee is the organization established to ensure the coordinated operation of the System. The Operating Committee members shall include at least one member from LG&E and at least one member from KU who are not members of the Coordinating Committee established under the Transmission Coordination Agreement. The chairperson, who shall be the Chief Operating Officer of LEC, shall appoint the member representative(s) of LG&E and KU. Other than the chairperson, there shall be the same number of members representing each Company. Operating Committee decisions shall be by a majority vote of those present. However, any member not present may vote by proxy. The chairperson shall vote only in case of a tie.

4.2 Responsibilities of the Operating Committee

The Operating Committee shall be responsible for overseeing:

(a) coordinated planning of the Companies' Power Supply Resources;

(b) the design, construction, operation and maintenance of the Power Supply Control Center; and

(c) the Economic Dispatch of the System by the Power Supply Control Center and the provision of generation-based Ancillary Services by the Companies.

4.3 Delegation and Acceptance of Authority

The Companies hereby delegate to the Operating Committee, and the Operating Committee hereby accepts, responsibility and authority for the duties listed in this Article and elsewhere in this Agreement.

4.4 Reporting

The Operating Committee shall provide periodic summary reports of its activities under this Agreement to the Companies and shall keep the Companies informed of situations or problems that may materially affect the outcome of these activities. Furthermore, the Operating Committee agrees to report to the Companies in such additional detail as is requested regarding specific issues or projects under its oversight.

4.5 Expenses

All expenses incurred by the Operating Committee in the performance of its responsibilities shall be settled in accordance with arrangements made by the Companies for services provided between or on behalf of the Companies.

ARTICLE V

GENERATION PLANNING

5.1 Generation Planning

The Companies agree that additions to Company Operating Capability shall be planned and developed on the basis that their combined individual systems constitute an integrated electric system and that the objective of their planning shall be to maximize the economy, efficiency and reliability of the System as a whole. In this connection, the Operating Committee will from time to time, as it deems appropriate, direct studies for Power Supply Resource planning purposes. If the Companies agree to participate in Joint Units, such Joint Units shall be owned in accordance with **Schedule A.**

ARTICLE VI

COORDINATED OPERATION

6.1 Operation of the Combined System

The System shall be operated in accordance with Economic Dispatch in order to economically meet the Company Load Responsibility of each Company and its off-System sales obligations, through the coordinated economic commitment and dispatch of the Companies' Power Supply Resources, consistent with Good Utility Practice.

6.2 Communications Facilities and Other Facilities

The Companies shall provide communications, metering and other facilities necessary for the metering and control of the Generating Units. Each Company shall be responsible for any expenses it incurs for the installation, operation and maintenance of such facilities at its own Generating Units. Any expenses incurred due to facilities required at or for the Power Supply Control Center to operate the System shall be settled in accordance with the arrangements made by the Companies for compensation for services provided between and on behalf of the Companies.

ARTICLE VII

OFF-SYSTEM CAPACITY AND ENERGY SALES AND PURCHASES

7.1 Revenues From Pre-Merger Off-System Capacity Sales

With respect to contracts in effect as of the effective date of this Agreement for off-System sales of Capacity only or for the sale of both Capacity and Energy, all revenues collected for pre-merger off-System capacity sales (less costs incurred to make such sales) shall remain with the Company contracting for the sale, except that such revenue shall be reduced by any demand charges incurred to supply the off-System capacity sales pursuant to Section 7.4 (pertaining to demand charges from post-merger off-System purchases).

7.2 Revenues From Post-Merger Off-System Capacity Sales

Demand and Energy charge revenues collected from post-merger off-System Capacity sales shall be reduced by any demand charges from off-System purchases, if any, dedicated to supply the sale, pursuant to Section 7.4. The net amount of revenue shall inure to the Company providing the Capacity for the sale.

7.3 Charges for Pre-Merger Off-System Capacity Purchases

Demand and Energy charges for pre-merger off-System Capacity purchases agreed to as of the effective date of this Agreement shall remain the responsibility of the Company contracting for the purchase.

7.4 Charges for Post-Merger Off-System Capacity Purchases

Demand charges associated with post-merger off-System capacity purchases made to enable both Companies to reliably and economically meet their Company Load Responsibility shall be assigned to the Companies based on the ratio of the Company Load Responsibility of each Company to the sum of the Company Load Responsibility for both Companies for the appropriate time period.

Demand charges associated with post-merger off-System capacity purchases made to enable the Companies to make post-merger off-System sales or to supply pre-merger off-System sales shall be deducted from the demand charge revenue collected from the off-System sales. The net amount shall be allocated to the Companies pursuant to Sections 7.1 (pertaining to demand charges from pre-merger off-System capacity sales) and 7.2 (pertaining to demand charges from post-merger off-System capacity sales).

This section applies only to demand charges associated with post-merger off-System capacity purchases.

7.5 Energy Sales and Purchases Off-System

The Operating Committee will assure the efficient utilization of Company Operating Capability for off-System sales of Energy available after meeting all of the requirements of the System including the Energy associated with contractual requirements for off-System Capacity sales. Any off-System economy Energy purchases or sales shall be implemented by decremental or incremental System Economic Dispatch as appropriate. Any Margin on Energy Sales to off-System entities shall be distributed to the Companies based on the amount of Energy each contributes to the transaction, in accordance with **Schedule B.** Any cost for Energy purchases from off-System entities shall be allocated to the Companies based on the amount of Energy replaced for each Company, in accordance with **Schedule B**.

ARTICLE VIII

INTER-COMPANY ENERGY EXCHANGES AND CAPACITY PURCHASES

8.1 Energy Exchanges Between the Companies

The Power Supply Control Center shall direct the scheduling of System Energy output pursuant to guidelines established by the Operating Committee to obtain the lowest cost of Energy for serving System Demand consistent with each Company's operating and security constraints, including voltage control, stability, loading of facilities, operating guides as approved by the Operating Committee, fuel commitments, environmental requirements, and continuity of service to customers.

8.2 Energy Exchange Pricing

For purposes of pricing Energy exchange between the Companies, Power Supply Resources shall be utilized in the following order:

(a) The portion of output of a Generating Unit that is designated not to be operated in the order of lowest to highest Variable Cost due to Company operating constraints shall be allocated to the Company requiring such output;

(b) The lowest Variable Cost generation from each Company's Operating Capability remaining after the requirements in (a) have been met shall first be allocated to serve its Own Load;

(c) The next lowest Variable Cost portion of each Company's Operating Capability remaining after the requirements in (a) and (b) have been met shall be allocated to serve Internal Economy Energy requirements of the Companies under System Economic Dispatch; and

(d) the next lowest Variable Cost portion of each Company's Operating Capability remaining after the requirements of (a), (b), and (c) have been met shall be available for off-System Energy sales.

Internal Economy Energy shall be priced in accordance with **Schedule C.**

ARTICLE IX

Power Supply Control Center

9.1 <u>Power Supply Control Center</u>

The Operating Committee shall oversee the operation of a Power Supply Control Center adequately equipped and staffed to meet the requirements of the Companies for efficient, economical and reliable operation as contemplated by this Agreement.

9.2 Expenses

All expenses for operation of the Power Supply Control Center shall be billed Monthly to each Company, in accordance with **Schedule D**.

ARTICLE X

GENERAL

10.1 Regulatory Authorization

This Agreement is subject to certain regulatory approvals and the Companies shall diligently seek all necessary regulatory authorization for this Agreement.

10.2 Effect on Other Agreements

This Agreement shall not modify the obligations of either Company under any agreement between such Company and others not parties to this Agreement in effect at the date of this Agreement.

10.3 Schedules

The basis of compensation for the use of facilities and for the Capacity and Energy provided or supplied by a Company to the other Company under this Agreement shall be in accordance with arrangements agreed upon from time to time between the Companies, each of which, when signed by the parties thereto and approved or accepted for filing by the appropriate regulatory authority, shall become a part of this Agreement.

10.4 Measurements

All quantities of Capacity and Energy exchanged or flowing between the systems of the Companies, shall be determined by meters installed at each interconnection, unless otherwise agreed to by the Companies.

10.5 Billings

Bills for services rendered hereunder shall be calculated in accordance with applicable Schedules, and shall be issued on a Monthly basis for services performed during the preceding Month.

10.6 Waivers

Any waiver at any time by a Company of its rights with respect to a default by the other Company under this Agreement shall not be deemed a waiver with respect to any subsequent default of similar or different nature.

10.7 Successors and Assigns; No Third Party Beneficiary

This Agreement shall inure to and be binding upon the successors and assigns of the respective Companies, but shall not be assignable by either Company without the written consent of the other Company, except upon foreclosure of a mortgage or deed of trust. Nothing expressed or mentioned or to which reference is made in this Agreement is intended or shall be construed to give any person or corporation other than the Companies any legal or equitable right, remedy or claim under or in respect of this Agreement or any provision herein contained, expressly or by reference, or any Schedule hereto, this Agreement, any such Schedule and any and all conditions and provisions hereof and thereof being intended to be and being for the sole and exclusive benefit of the Companies, and for the benefit of no other person or corporation.

10.8 Amendment

It is contemplated by the Companies that it may be appropriate from time to time to change, amend, modify or supplement this Agreement or the schedules which are attached to this Agreement, to reflect changes in operating practices or costs of operations or for other reasons. This Agreement may be changed, amended, modified or supplemented by an instrument in writing executed by the Companies after requisite approval or acceptance for filing by the appropriate regulatory authorities.

10.9 Independent Contractors

By entering into this Agreement the Companies shall not become partners, and as to each other and to third persons, the Companies shall remain independent contractors in all matters relating to this Agreement.

10.10 Responsibility and Liability

The liability of the Companies shall be several, not joint or collective. Each Company shall be responsible only for its obligations, and shall be liable only for its proportionate share of the costs and expenses as provided in this Agreement, and any liability resulting herefrom. Each Company will defend, indemnify, and save harmless the other Company hereto from and against any and all liability, loss, costs, damages, and expenses, including reasonable attorney's fees, caused by or growing out of the gross negligence, willful misconduct, or breach of this Agreement by such indemnifying Company.

IN WITNESS WHEREOF, each Company has caused this Agreement to be executed and attested by their duly authorized officers on the day and year first above written.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: S.W. Wood
President

KENTUCKY UTILITIES COMPANY

By: Robert M Hewett
President

SCHEDULE A

JOINT UNIT

1. Purpose

The purpose of this Schedule is to provide the basis for the Companies' participation in Joint Units.

2. Ownership

(a) Every Joint Unit shall be owned by the Companies as tenants in common. Ownership shares in each Joint Unit shall be allocated by the Operating Committee prior to the time the unit is authorized by the Board of Directors of LEC. However, each Company shall own at least 25 megawatts of each Joint Unit unless otherwise agreed to by the Operating Committee. Each Company shall be responsible for its pro-rata share of the costs of construction of the unit and shall contribute such funds when billed.

(b) When a new Joint Unit is installed at a site already occupied by one or more existing (i.e., pre-merger) Generating Units, the Operating Committee shall identify any existing facilities that will be common to the new Joint Unit and the existing Generating Unit(s) and the portion of the common facilities to be allocated to the new Joint Unit. The Company owning the existing common facilities shall be compensated for the use of those common facilities.

LOUISVILLE GAS AND ELECTRIC COMPANY

By:______________________________
President

KENTUCKY UTILITIES COMPANY

By: Robert M Hewett
President

SCHEDULE B

DISTRIBUTION OF MARGIN FOR OFF-SYSTEM SALES AND COST FOR ENERGY PURCHASES

1. Purposes

The purpose of this Schedule is to establish the basis for distributing between the Companies the cost of Energy purchases and the Margin on Energy Sales of off-System Energy.

2. Off-System Energy Purchases

Any cost for Energy purchases of off-System Energy during an Hour shall be allocated to the Companies in proportion to the megawatt-hours of Energy replaced for each Company during the Hour as a result of the purchases.

3. Off-System Energy Sales

Any Margin on Sales of off-System Energy during an Hour shall be distributed to the Companies in proportion to the Energy generated by each Company for such sales unless such Energy was generated for off-System Sales as a result of a Company's purchase of Internal Economy Energy pursuant to Schedule C, in which case the Margin from such sales shall inure to the benefit of the Company furnishing the Internal Economy Energy.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: ____________________
President

KENTUCKY UTILITIES COMPANY

By: Robert M Hewett
President

SCHEDULE C

PAYMENTS AND RECEIPTS FOR INTERNAL ECONOMY ENERGY EXCHANGES BETWEEN THE COMPANIES

1. Purpose

The purpose of this Schedule is to provide the basis for determining payments and receipts between the Companies for Internal Economy Energy exchanges.

2. Hourly Calculations

The payments and receipts of Section 3 of this Schedule are calculated Hourly, but are accumulated and billed Monthly between the Companies.

3. Payments and Receipts

The purchasing Company shall pay, and the selling Company shall receive, an amount based on the incremental fuel cost of the selling Company plus one half of the difference between the incremental fuel cost of the selling Company and the avoided fuel cost of the purchasing Company.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: S R Wood
President

KENTUCKY UTILITIES COMPANY

By: Robert M Hewett
President

SCHEDULE D

DISTRIBUTION OF OPERATING EXPENSES
OF THE POWER SUPPLY CONTROL CENTER

1. Purpose

The purpose of this Schedule is to provide a basis for the distribution between the Companies of the costs incurred in operating the Power Supply Control Center.

2. Costs

Costs for the purpose of this Schedule shall include all costs incurred in maintaining and operating the Power Supply Control Center including, among others, such items as salaries, wages, rentals, the cost of materials and supplies, interest, taxes, depreciation, transportation, travel expenses, consulting, and other professional services.

3. Distribution of Costs

All costs other than those relating to a special service or study shall be billed to the Companies in proportion to all firm kilowatt hour electric sales made by each Company for the preceding Year. In the event the Power Supply Control Center performs a special service or study in which both Companies are not proportionately interested, any resulting cost shall be distributed as agreed to by the Companies.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: J.M. Wood
President

KENTUCKY UTILITIES COMPANY

By: Robert M. Hewett
President

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 8

Witness: John N. Voyles, Jr.

Q-8. Reference the testimony of Thompson at page 6 regarding the solar facility wherein he states that the Companies will "gain the valuable experience that will result from constructing and operating that source." Provide the following:

a. List each and every individual, by name and title, presently employed by each company that has actual, hands-on experience in operating a solar unit;

b. For each and every person listed in the above answer, provide in detail the experience; and

c. For each and every person listed in the above answer, provide any and all credentials, certifications, etc. that relate to the operation and/or maintenance of a solar facility.

A-8.

a. The Companies have no employees with actual, hands-on experience in operating a solar facility.

b. Not applicable.

c. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 9

Witness: John N. Voyles, Jr.

Q-9. Reference the testimony of Thompson regarding the solar facility at page 6. Explain in detail the "$7 million for owner's costs."

A-9. The following details are included in the $7 million for Owner's Costs:

Owner's Cost	
Project Development	$650,000
Electrical Interconnect	$450,000
Construction Power	$50,000
Owners Project Management	$500,000
Owners Engineer	$170,000
Owners Legal Counsel	$250,000
Electric Transmission Service	$50,000
Site Security	$50,000
Spare Parts	$100,000
AFUDC (KU Portion)	$150,000
Contingency	$4,350,000
Total	$6,770,000

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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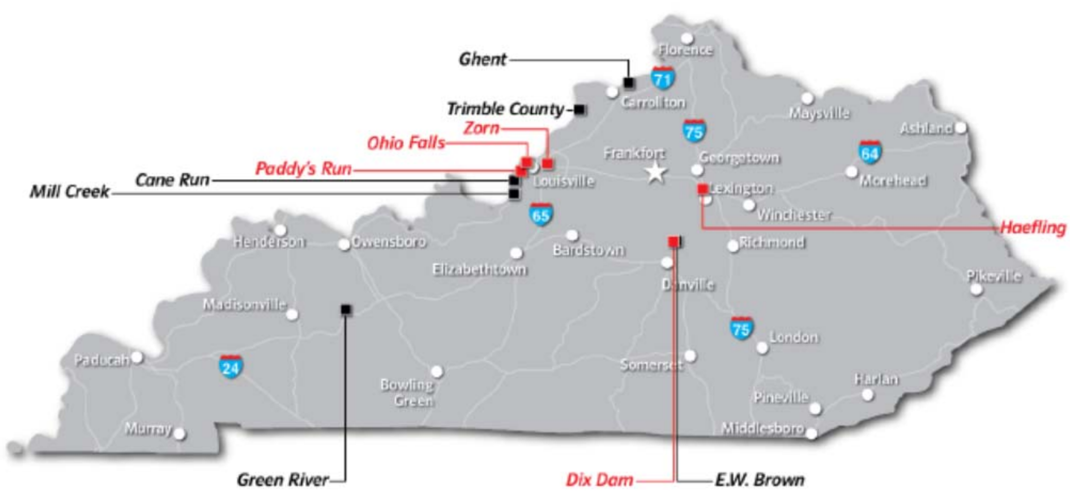
Question No. 10

Witness: Paul W. Thompson

Q-10. Reference the application and testimony of Thompson in general. Provide a map illustrating the name, location, size (in WH) and ownership (e.g., 100% for KU, etc.) for every generator that the companies own in the Commonwealth.

A-10. See the map below illustrating the name and location of each generating facility the companies own in the Commonwealth. The size and ownership for each generator is included in the table below.



Generating Unit	KU Ownership %	LG&E Ownership %	Net Summer Rating (MW)
Brown 1	100		106
Brown 2	*100*		168
Brown 3	100		410
Brown IAC	90	10	98
Brown 5	47	53	112
Brown 6	62	38	146
Brown 7	62	38	146
Brown 8	100		102
Brown 9	100		102
Brown 10	100		102
Brown 11	100		102
Cane Run 4		100	155
Cane Run 5		100	168
Cane Run 6		100	240
Cane Run 11		100	14
Dix Dam 1	100		8
Dix Dam 2	100		8
Dix Dam 3	100		8
Ghent 1	100		479
Ghent 2	100		495
Ghent 3	100		489
Ghent 4	100		469
Green River 3	100		68
Green River 4	100		93
Haefling 1	100		12
Haefling 2	100		12
Mill Creek 1		100	303
Mill Creek 2		100	301
Mill Creek 3		100	391
Mill Creek 4		100	477
Ohio Falls 1		100	6
Ohio Falls 2		100	6
Ohio Falls 3		100	6
Ohio Falls 4		100	6
Ohio Falls 5		100	8
Ohio Falls 6		100	8
Ohio Falls 7		100	8
Ohio Falls 8		100	6
Paddys Run 11		100	12
Paddys Run 12		100	23
Paddys Run 13	47	53	147
Trimble County 1*		100	383
Trimble County 2*	81	19	549
Trimble County 5	71	29	157
Trimble County 6	71	29	157
Trimble County 7	63	37	157
Trimble County 8	63	37	157
Trimble County 9	63	37	157
Trimble County 10	63	37	157
Zorn 1		100	14

*Values reflect Companies' 75 percent share of Trimble County 1 and 2.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 11

Witness: John N. Voyles, Jr.

Q-11. Reference the testimony of Thompson at page 9 wherein he states: "For those employees that are not reassigned, the Companies believe that they will either retire or be offered severance packages." Can the Companies state when the decision will be made regarding the effected employees?

A-11. The Companies have yet to identify a final date when the units will be retired and complete the necessary decommissioning activities. Once that is determined, a decision will be made regarding the affected employees.

Refer to the Companies' response to the PSC 1-29(a) for a discussion of the retirement of Green River units 3 and 4.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 12

Witness: John N. Voyles, Jr.

Q-12. Reference the testimony of Thompson at page 9 wherein he states: "The operation of the Brown Solar facility is expected to be staffed by current employees already located at Brown." For each individual presently employed at the Brown location, provide the following:

a. Name and title;

b. Whether the person has hands-on experience in operating a solar unit;

c. The details of the experience; and

d. Any and all credentials, certifications, etc. that relate to the operation and/or maintenance of a solar facility.

A-12. The Companies object to this request on the grounds that the information it seeks is not relevant to the issues in this proceeding. Notwithstanding this objection, see the Companies' response to Question No. 8.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 13

Witness: David S. Sinclair

Q-13. Reference the testimony of Mr. Sinclair at p. 2. In regard to the Sales Analysis and Forecasting group, provide the following:

a. The names and titles of each member who were on the group who provided the load forecast noted in the application;

b. The level of education, training and experience of each individual noted in the above answer; and

c. The information, whether in document form or otherwise (if electronic data was used this should be provided in Excel format with all formulae and cells intact), reviewed or considered by the group in making their recommendation or decision.

A-13.

a. The following Sales Analysis and Forecasting employees were on the group who provided the load forecast:

- Greg Lawson, Manager Sales Analysis and Forecasting
- Monica Greer, Senior Energy Analyst
- Jason Renfro, Energy Analyst III
- Stephen Heiniger, Energy Analyst II
- Charles McKenna, Energy Analyst II

b. See table below:

Group Member	Education/Training	Years of Experience
Greg Lawson	BS, Mathematics, MBA	24
Monica Greer	Ph.D. Economics	29
Jason Renfro	BS Mathematics, MBA	11
Stephen Heiniger	BS Economics	4
Charles McKenna	BS Economics, MBA	6

c. See attached files. Certain information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection. The Companies will continue to review all records and will supplement the data response if additional responsive information is found.

File Name	**Data Provided**
Attachment to AG 1-13-#1 IHSExecutiveSummary.pdf	Macroeconomic
Attachment to AG 1-13-#2 useconomic-30yrfocus1Q12.pdf	Macroeconomic
Attachment to AG 1-13-#3 KYLT Q.xlsx	Macroeconomic
Attachment to AG 1-13-#4 CustomerData.xlsx	Customer
Attachment to AG 1-13-#5 EnergyData.xlsx	Energy
Attachment to AG 1-13-#6 HistoricalWeather.xlsx	Weather
Attachment to AG 1-13-#7 2012-2013MeterReadSchedule.xlsx	Billing Cycle Forecasts
Attachment to AG 1-13-#8 CommercialEastSouthCentral11.xlsx	Appliance
Attachment to AG 1-13-#9 KUEnergyChargesByRate.xlsx	Price Series
Attachment to AG 1-13-#10 LGEElectricEnergyChargesByRate.xlsx	Price Series
Attachment to AG 1-13-#11 ResidentialEastSouthCentral11.xlsx	Appliance
Attachment to AG 1-13-#12 MajorCustomers.xlsx	Major Accounts
Attachment to AG 1-13-#13_PopulationHouseholds.xlsx	Population & Households
Attachment to AG 1-13-#14_DSMPrograms.xlsx	DSM Programs
Attachment to AG 1-13-#15 DTRep.xlsx	Hourly Forecasts
Attachment to AG 1-13-#16 HourlyLoadwithLosses.xlsx	Hourly Forecasts
Attachment to AG 1-13-#17 KUHourlyFcst.xlsx	Hourly Forecasts
Attachment to AG 1-13-#18 LEHourlyFcst.xlsx	Hourly Forecasts

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 14

Witness: David S. Sinclair

Q-14. Reference the testimony of Mr. Sinclair at p. 2. With regard to the Generation Planning group, provide the following:

a. The names and titles of each member who were on the group who provided the alternative generation options noted in the application;

b. The level of education, training and experience of each individual noted in the above answer; and

c. The information, whether in document form or otherwise (if electronic data was used this should be provided in Excel format with all formulae and cells intact), reviewed or considered by the group in making their recommendation or decision.

A-14.

a. The following Generation Planning employees provided the analysis of the alternative generation options:
- Stuart Wilson, Manager Generation Planning
- Monica Farhat, Planning Analyst II
- Brian Hurst, Planning Analyst II
- Lou Anne Karavayev, Planning Analyst II
- Chung-Hsiao Wang, Financial Engineering and Modeling Analyst

b. See the table below.

Group Member	Education/Training	Years of Experience
Stuart Wilson	BSEE, MENG, MBA, CFA	16
Monica Farhat	BSEE, MENG, MBA	5
Brian Hurst	BSIE, MENG, MBA	6
Lou Anne Karavayev	BSEE	5
Chung-Hsiao Wang	BSIE, MENG, PhD Engineering	12

c. See the response to PSC 1-22.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 15

Witness: David S. Sinclair

Q-15. Reference the testimony of Mr. Sinclair at p. 2, line 17 where the witness discusses the "customers' future capacity and energy needs in a lowest-cost manner."

a. Does lowest-cost manner mean a pure cost based decision stated in actual, definitive, quantifiable dollars? If not, please explain; and

b. Does lowest-cost manner also include any extrapolation of dollar value of other factors? If yes, please identify those factors and the dollar value associated with each one(s).

A-15.

a. Yes.

b. No.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 16

Witness: David S. Sinclair

Q-16. Reference the application in general (with some emphasis at the table on page 4), the testimony of Mr. Sinclair in general and specifically at p. 4, lines 16-17. Confirm that the Companies have compiled this application with the assumption that the energy efficiency through its DSM program as listed in Table 5 of Sinclair's testimony is essential to the company's application. If confirmation cannot be provided, state the reason(s) why not.

A-16. The statement is correct.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 17

Witness: David S. Sinclair

Q-17. Confirm that the energy efficiency through the DSM program as contained in the application is the same of energy efficiency as filed in Case No. 2014-00003. If confirmation cannot be provided, state the reason(s) why not.

A-17. See the response to PSC 1-14.

In addition, energy reduction for the 2014 DSM Filing is greater than the energy reduction in both the 2013 and 2014 LF due to the higher customer participation from the Companies' approved plan associated with the Residential Appliance Rebate Program. The Companies have requested in Case No. 2014-00003 to add funding to allow the program to continue at the higher participation levels through 2018. Assuming customer participation continues at the new proposed plan, an additional 500 GWh of energy reduction would result.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 18

Witness: David S. Sinclair

Q-18. Reference the testimony of Mr. Sinclair at p. 5. Provide all data, in Excel format (with formulae and cells intact if possible) relative to the inputs listed:

a. Macroeconomic data;

b. Historical energy and customer data;

c. Weather data (20-year normal degree-day series); and

d. Other data including billing cycle forecasts, class-level electricity price series, and residential appliance shares and efficiencies.

A-18. See the response to Question No. 13(c).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 19

Witness: David S. Sinclair

Q-19. Reference the testimony of Mr. Sinclair at p. 5. If the "Companies prepare a 30 year demand and energy forecast" each year, why did the Companies not use 30 year weather data?

A-19. The number of forecast years does not set the minimum or maximum number of years of historical weather to utilize for estimating "normal" weather. For example, a five year demand and energy forecast would not necessarily limit the "normal" weather data to five years.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 20

Witness: David S. Sinclair

Q-20. Reference the testimony of Mr. Sinclair at p. 5 where the witness states that the forecasting approach "incorporates specific intelligence on the prospective energy needs of the Companies' largest customers" and "[t]his process allows for market intelligence to be directly incorporated into the sales forecast."

a. Explain in laymen's terms what information is considered; and

b. Provide all data, in both .pdf and Excel format with all formulae and cells intact, pertaining to the "intelligence" referenced.

A-20.

a. The Companies maintain close contact with their largest customers to gather information such as production level expectations, potential expansions or reductions, and any other expected significant operational changes affecting energy usage and demand levels. Ultimately, this information is provided at the discretion of the customer.

b. See the response to Question No. 13(c), Attachment to AG 1-13-#12 MajorCustomers.xlsx.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 21

Witness: David S. Sinclair

Q-21. Reference the testimony of Mr. Sinclair at p. 5, lines 15 – 17. Provide all information pertaining to the "recent history and information provided by the customers to the Companies regarding their outlook."

A-21. See the response to Question No. 13(c).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 22

Witness: David S. Sinclair

Q-22. Confirm that both Companies have experienced new record demand and energy levels during the 2013 -2014 winter. If confirmation cannot be provided, explain why not.

A-22. The Companies experienced a new winter peak in January 2014 of 7,114 MW. However, this did not reach the all-time peak of 7,175 MW set in August 2010.

The Companies did experience a new record daily energy requirement of 153,967 MWh in January 2014.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 23

Witness: David S. Sinclair

Q-23. Reference the testimony of Mr. Sinclair on p. 6 at lines 16–17, and pp. 12-16. Should the "2013 LF" forecast continue to be used in this application given the 2013–2014 winter? If yes, please explain. If not, explain why not.

A-23. Yes. The record high load in January 2014 was caused by extreme weather conditions while long-term load forecasts like the 2013 LF are based on "normal" weather.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 24

Witness: David S. Sinclair

Q-24. Reference the testimony of Mr. Sinclair at p. 7. Provide all data and forecasts that the Companies obtained from HIS Global Insight.

A-24. See the response to Question No. 13(c), Attachment to AG 1-13-#1 IHSExecutiveSummary.pdf, Attachment to AG 1-13-#2 useconomic-30yrfocus1Q12.pdf, Attachment to AG 1-13-#3 USLT_Q.xlsx.

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Question No. 25

Witness: David S. Sinclair

Q-25. Reference the testimony of Mr. Sinclair at pp. 7-8. Provide all data and forecasts that the Companies obtained from the Kentucky State Data Center.

A-25. See the response to Question No. 13(c), Attachment to AG 1-13-#13_PopulationHouseholds.xlsx.

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Question No. 26

Witness: David S. Sinclair

Q-26. Reference the testimony of Mr. Sinclair at p. 8. Please explain in quantitative terms the "effect of improving appliance efficiency and their adoption by customers."

A-26. The Companies have not produced "with" and "without" future energy efficiency forecasts necessary to answer this question. Assumptions about improving appliance efficiency is found in response to Question 13(c), "AG 1-13-#22 SAE RS&GS Efficiency.xlsx."

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Question No. 27

Witness: David S. Sinclair

Q-27. Reference the testimony of Mr. Sinclair at p. 9. Confirm that the Companies have filed a new DSM case, Case No. 2014-00003.

a. Confirm or deny that the Companies have incorporated the potential energy savings from Case No. 2014-00003 into this filing;

b. Explain the basis for either the denial or the confirmation; and

c. If the Companies deny that the potential energy savings have been incorporated into this filing, please explain why the application is not premature to file until the Commission renders a decision on Case No. 2014-00003.

A-27.

a.-b. See the response to PSC 1-14.

c. Not applicable.

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Question No. 28

Witness: David S. Sinclair

Q-28. Reference the testimony of Mr. Sinclair at p. 12, line 24 regarding "climate change." What is meant by climate change?

a. Do the Companies believe that climate change is a phrase that denotes a change in the earth's weather conditions that is exclusively attributable to mankind's behavior? If yes, please explain. If not, explain why not.

b. Do the Companies believe that the climate is changing as an exclusive result of mankind's behavior? Please explain the answer.

A-28. According to NASA, climate change is "a long-term change in the Earth's climate, or of a region on Earth."[1]

a. and b. The Companies have not taken a position on whether or not climate change is exclusively attributable to mankind's behavior.

[1] http://www.nasa.gov/topics/earth/features/climate_by_any_other_name html

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Question No. 29

Witness: David S. Sinclair

Q-29. Reference the testimony of Mr. Sinclair at p. 15 whereat the witness states: "The Companies seek to ensure their load forecast is prepared using sound methods by people who are qualified professionals."

a. Explain in detail the sound methods used; and

b. Provide the following with regard to the qualified professionals: (i) the names and titles of each person; and (ii) the level of education, training and experience of each individual noted in the above answer.

A-29.

a. The methods used to prepare the 2013 LF are not materially different from those discussed in Section 7 of the 2011 IRP. These methods were reviewed by the Commission and no material issues were identified.

See Commission finding on 2011 IRP (Case No. 2011-00140)

b. See the response to Question No. 13(a) and (b).

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Question No. 30

Witness: David S. Sinclair

Q-30. Reference the testimony of Mr. Sinclair at p. 16. Provide the necessary model(s), data, etc. that would enable a third party to replicate the Companies' results on the 2013 LF forecast.

A-30. The 2013 LF was developed using proprietary third-party software that cannot be provided without a license from the vendors. Software used includes Base SAS, SAS Enterprise Guide, Itron MetrixLT, Itron MetrixND, Palisade Corporation @Risk and the Microsoft Office suite. See the response to Question No. 13(c) for input data.

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Question No. 31

Witness: David S. Sinclair

Q-31. Reference the testimony of Mr. Sinclair at p. 20. Describe in detail the "broad spectrum of technology" that the Companies explored.

A-31. See Exhibit DSS-1 at page 6. Natural gas, coal, wind, biomass, and solar technologies were included in the responses to the Companies' request for proposals.

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Question No. 32

Witness: John N. Voyles, Jr.

Q-32. Reference the testimony of Mr. Sinclair at p. 21, line 1. Provide the name of the engineering firm engaged to "help identify potential self-build alternatives and the costs for each."

a. Is the engineering firm associated in any way with the either of the Companies? If so: (i) which one(s)? and (ii) describe in detail.

b. Provide the following information regarding the engineering firm:

(i) Names and qualifications for each individual providing services to the Companies;
(ii) Total amount paid to date to the firm;
(iii) Total projected amount to be paid to the firm; and
(iv) If possible, provide the amount to be paid, or has been paid, to the firm broken down by type of service provided or will be provided.

A-32. The engineering firm used to help identify potential self-build resources was HDR.

a. HDR is not an affiliate of either of the Companies.
b. See the response to Question No. 6.

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Question No. 33

Witness: John N. Voyles, Jr.

Q-33. Reference the testimony of Mr. Sinclair at p. 21, at lines 12-15. Provide a detailed explanation of the statement that "replacing the retiring generation at the Green River Station will reduce the need to rely more heavily on the transmission grid in the western part of the Companies' service area."

A-33. The Companies currently have approximately 600 MW of customer load in the western part of the state. Generating units, including the Companies' and units owned by others, are necessary to both serve and provide voltage support for the load. In the absence of some locally situated generation, appropriate components of the transmission grid can be improved to provide a means for supporting voltage and reliability. In anticipation of the retirement of the Green River units, the companies have constructed additional transmission components to improve the reliability of the Companies' transmission network in that part of the state.

Since the Companies announced plans to retire the Green River units, other companies have made or are contemplating decisions to retire or shutdown generation in western Kentucky. Additionally, regional developments, including the expanded MISO balancing area, may drive power flows on the interconnected grid that are different than the historical flows for which the system has been planned and constructed. The statement referenced in Mr. Sinclair's testimony recognizes this uncertainty and the associated reliability risk. Adding generation owned by the Companies at the Green River Station would reduce this risk for our customers in western Kentucky.

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Question No. 34

Witness: David S. Sinclair

Q-34. Reference the testimony of Mr. Sinclair at p. 21, lines 18 – 22 whereat the witness states that the Companies "assumed that a commercial new construction program might be a viable future DSM program. Therefore, the load forecast was reduced accordingly."

a. Is the commercial new construction program referenced in the testimony the same program requested in Case No. 2014-00003? If not, explain how it is different.

b. If the commercial new construction program referenced in the testimony is the same program requested in Case No. 2014-00003, is it not premature to proceed with this application until the Commission decides Case No. 2014-00003? If not, explain why not.

A-34.

a. See the response to Question No. 17.

b. No. As shown in Table 24 on page 31 of Exhibit DSS-1, the commercial new construction program is forecasted to be approximately 2 MW in 2018 and would not impact the need or economics associated with Green River NGCC or Brown Solar Facility.

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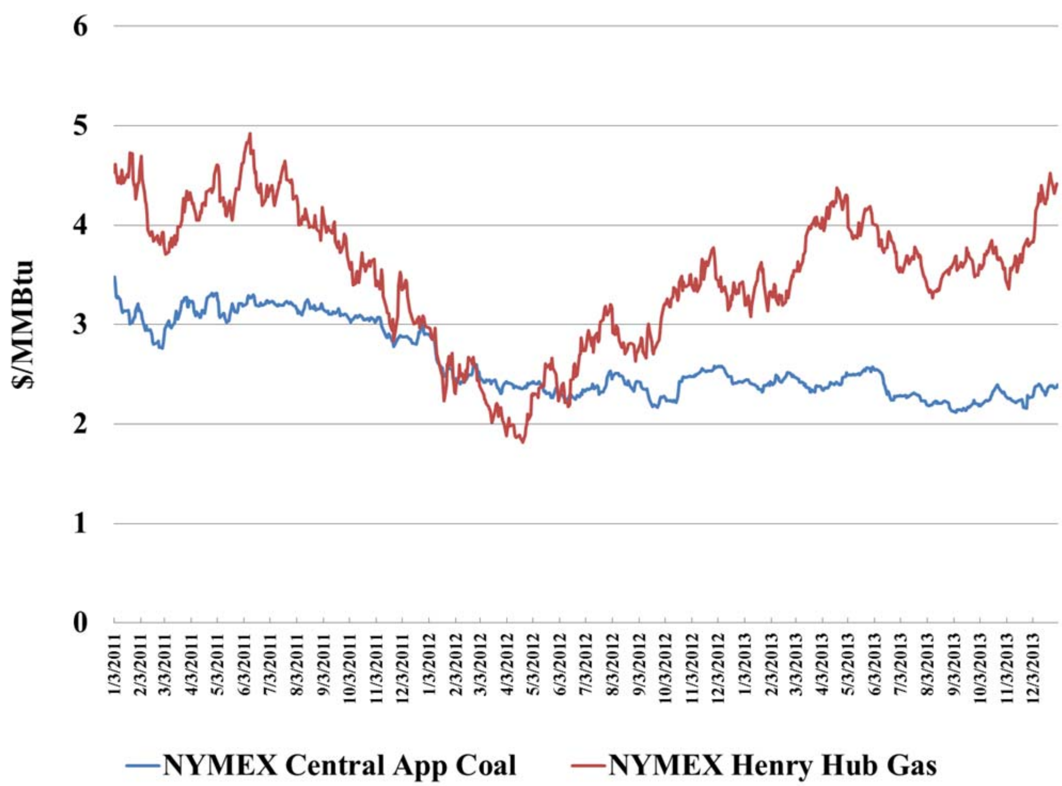
Question No. 35

Witness: David S. Sinclair

Q-35. Reference the testimony of Mr. Sinclair at p. 23 where the witness states that "natural gas prices have tended to be more volatile than coal prices" and also refers to the "low volatility associated with coal prices." Provide all analyses, reports, studies, etc. that the Companies used in reviewing the volatility of coal prices.

A-35. The graph below demonstrates how NYMEX spot natural gas prices and NYMEX Central Appalachian coal futures prompt quarter contract settlement prices varied in response to market factors from 2011 through2013 on an equivalent dollars per MMBtu basis.



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Question No. 36

Witness: David S. Sinclair

Q-36. Reference the testimony of Mr. Sinclair at p. 24 whereat the witness references the CO_2 prices and the timing for CO_2 regulation as prepared by Synapse Energy Economics, Inc. Provide all information that Synapse used in the determination of the data upon which the Companies relied in their modeling.

A-36. Synapse Energy Economics, Inc.'s publicly available document, "2012 Carbon Dioxide Price Forecast" (October 4, 2012), is available at http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

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Question No. 37

Witness: David S. Sinclair

Q-37. Reference the testimony of Mr. Sinclair at p. 25 at lines 3–6 where the witness states: "However, the Companies feel that enough is known that the risk of future CO_2 regulations should be part of a 30-year analysis related to the next generation resource and that a resource should be economically robust with or without future CO_2 regulations." Is the witness aware that the Commission previously held in Case No. 2009-00545 that possible legislation is not to be considered as determinative of the Commission's consideration of the least cost option in determining purchased power agreements?

A-37. The Companies object to this question because it appears to call for a legal interpretation of the Commission's June 8, 2010 Order in Case No. 2009-00545. Notwithstanding that objection, the question inaccurately characterizes the Commission's holding in that Order. Mr. Sinclair is aware of that Order, but disagrees that its holding is as characterized in this question.

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Question No. 38

Witness: David S. Sinclair

Q-38. Reference the testimony of Mr. Sinclair at p. 25 at lines 6–8 where the witness states: "I would add, however, that there is not enough known about the potential for CO_2 regulations to evaluate material changes to the Companies' existing generation fleet." Is this statement not inconsistent for planning purposes for existing generation versus the new, planned generation determination? If not, why not?

A-38. No. This CPCN case is about adding new generation to the Companies' fleet in order to replace generation that is scheduled to retire and to meet customers' future energy needs. The proposed Green River NGCC and Brown Solar Facility will both meet the proposed CO_2 emission standards for new units. Should future CO_2 regulations on existing units limit the ability of the Companies to operate units in their existing fleet, then more generation will be needed from units like Green River NGCC and Brown Solar Facility that meet CO_2 emission standards. The need for Green River NGCC and Brown Solar Facility is not dependent upon additional retirements of the Companies' generation fleet that might result from CO_2 regulations on existing units.

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Question No. 39

Witness: David S. Sinclair

Q-39. Reference the testimony of Mr. Sinclair at p. 27 at lines 6–13 where the witness states: "While the Brown Solar Facility is not a lowest reasonable cost resource absent REC prices greater than $57/REC, as can be seen in Tables 35, 36, and 37 in Exhibit DSS-1, the Companies are proposing to move forward with the project because (i) it is a prudent hedge against both GHG regulations and natural gas price risk; (ii) it will reduce the Companies' GHG emissions; (iii) it affords the Companies the opportunity gain operational experience with an intermittent renewable resource; and (iv) it does not materially add to revenue requirements over the next 30 years." Based on what definitive data do the Companies opine that the REC will reach $57? Provide that data or information.

a. Provide the exact amount that the revenue requirement will increase based on the Companies' assumptions; and

b. Provide the assumptions the Companies used in answering the question above.

A-39. The Companies have no opinion regarding the level of future solar REC prices. The $57/REC price is simply provided as the price level at which the solar facility begins to have a favorable impact on revenue requirements.

a. See Tables 35-37 in Section 4.6 of Exhibit DSS-1 pages 43-46 for the revenue requirement analysis associated with the Brown Solar Facility.

b. See the responses to PSC 1-22, PSC 1-31, and PSC 1-35.

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Question No. 40

Witness: David S. Sinclair

Q-40. Reference the testimony of Mr. Sinclair at page 27, lines 15-17 where the witness states: "Given the potential for CO_2 regulations in the future and the declining cost of solar panels, the Companies believed it made sense to fully evaluate a utility scale solar project in the Resource Assessment." Does the witness believe that generation planning should be based on potential CO_2 regulations?

A-40. Yes. See Mr. Sinclair's testimony at page 25, lines 3-6.

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Question No. 41

Witness: John N. Voyles, Jr.

Q-41. Reference the testimony of Mr. Sinclair at page 27, lines 22-23. Is the existing property referenced therein property already owned? If not, from whom did the Companies purchase the property?

A-41. Yes, the Companies own the property referenced in the testimony. See the response to PSC 1-5.

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Question No. 42

Witness: David S. Sinclair

Q-42. Reference the testimony of Mr. Sinclair at page 29, lines 3-20.

a. Identify the entity which did the due diligence on the financial strength;

b. Provide all the information that the entity reviewed;

c. Identify the entity which reviewed the reliability of the operations of the company under review; and

d. Provide all the information that the entity reviewed.

A-42.

a. The financial analysis was performed by the Companies' Credit and Contract Administration department based on information from S&P.

b. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

c. The operational risk assessment was performed by the Energy Supply and Analysis group.

d. The following documents were reviewed:

See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

See source referenced in footnote 31 on page 29 of Mr. Sinclair's testimony.

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Question No. 43

Witness: David S. Sinclair

Q-43. Reference the testimony of Mr. Sinclair at page 31 at lines 7–8 and 22-23. Provide all data upon which the Companies relied in deciding that the "increasing risk of CO_2 regulations and the potential for lower future natural gas prices" have changed since the prior Cane Run Unit 7 CPCN case.

A-43. As it relates to the increasing risk for CO_2 regulations, see Mr. Sinclair's testimony page 23, lines 18-19.

See attached. The attachment compares the "mid" natural gas price forecast from the current CPCN case with the forecasts utilized in the Cane Run Unit 7 CPCN case. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

CONFIDENTIAL INFORMATION REDACTED

Comparison of "Mid" Case Natural Gas Price Forecasts ($/MMBtu)

Year	2011 Resource Assessment	2013 Resource Assessment
2013	[redacted]	4.24
2014		4.41
2015		4.62
2016		4.67
2017		4.79
2018		4.93
2019		5.16
2020		5.39
2021		5.77
2022		6.22
2023		6.58
2024		6.88
2025		7.23
2026		7.56
2027		7.93
2028		8.22
2029		8.57
2030		8.95
2031		9.35
2032		9.81
2033		10.19
2034		10.58
2035		10.99
2036		11.42
2037		11.86
2038		12.32
2039		12.80
2040		13.30

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Question No. 44

Witness: David S. Sinclair

Q-44. Reference the testimony of Mr. Sinclair at page 34 whereat the witness states: "The Companies recently filed an energy efficiency potential study with the Commission and are filing concurrently with this CPCN application a Demand Side Management and Energy Efficiency Program Plan for new programs for the 2015-2018 time period. The study showed that a small amount of additional energy and demand savings can be achieved beyond the Companies' planned activity currently scheduled through 2018." Have those energy and demand savings been incorporated into the load forecast in this application? If not, why not?

A-44. No. Because of the absence of proposed programs to achieve the small amount of additional potential energy and demand reductions beyond 2018, these potential reductions were not included in the CPCN filing.

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Question No. 45

Witness: David S. Sinclair

Q-45. Reference page 1, bullet 3, of DSS-1, the Resource Assessment (hereinafter the "RA", "DSS-1," or "Resource Assessment").

a. Do the Companies agree that it is prudent industry practice to use an RFP in order to obtain the necessary information to determine generation needs of an electric utility? Explain the answer in detail with examples.

A-45.

a. The question is unclear. The Companies' "generation needs" are based on the difference between their forecasted load obligations and its existing generation resources. The Companies issue an RFP for generation resources in order to obtain the information needed to procure the lowest reasonable cost resource(s) to meet customers' future energy needs.

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Question No. 46

Witness: David S. Sinclair

Q-46. Reference DSS-1 at page 1 at bullet 4 where the document reads in part that: "the analysis of RFP responses and self-build alternatives focused on (i) finding the lowest reasonable cost long-term resource(s); and (ii) whether a short-term PPA could cost-effectively and reliably defer the need for the long-term resource(s). Is there a distinction between a standard that employs a least cost option versus one that uses a least reasonable cost approach? Explain the answer.

A-46. In evaluating the various responses to the Companies' RFP, the Companies performed a least cost analysis but they also had to consider each proposal's reasonableness, riskiness, and feasibility.

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Question No. 47

Witness: John N. Voyles, Jr.

Q-47. Reference DSS-1 in general. Are the Companies requesting authorization to construct a 700MW NGCC or a 670MW NGCC? Explain the answer in detail.

A-47. As described in Mr. Voyles' Direct Testimony at pages 3-4, the Companies have proposed and have asked for authorization to construct an approximately 700 megawatt net summer rating ("700 MW") natural gas combined cycle generating unit at the Green River station. As Mr. Voyles indicates on page 4 of his Direct Testimony, such authorization will enable the Companies to capitalize on market competitiveness and seek bids for generating units that are within a reasonable range of 700 MW. This strategy will result in achieving the best possible price for a generating unit so that maximum benefits can be achieved for customers.

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Question No. 48

Witness: David S. Sinclair

Q-48. Reference DSS-1 in general at page 6 whereat the document reads in part: "The Companies requested proposals from parties with resources that would qualify as a Designated Network Resource for transmission purposes." Provide a list of the parties noted in the sentence.

A-48. The referenced sentence was meant to convey that any resource that a prospective bidder might propose needed to be able to qualify as a Designated Network Resource for transmission purposes. The Companies did not pre-screen or pre-qualify any of the prospective bidders that received the RFP based on this attribute.

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Question No. 49

Witness: David S. Sinclair

Q-49. Reference DSS-1 in general at page 6 whereat the document reads in part: "Over the last year, the cost of solar panels has decreased substantially." Provide all information upon which the Companies relied in making this assertion.

A-49. See Section 4.6 of Exhibit DSS-1.

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Question No. 50

Witness: David S. Sinclair

Q-50. Reference DSS-1 at page 7 whereat the document reads in part: "The DSM programs that were considered in this analysis are summarized in Table 3. The Companies will be filing a DSM application in January 2014 that considered numerous DSM programs. The DSM programs in Table 3 are the most competitive programs that will not be included in the DSM filing." Please explain what DSM programs, and the associated capacity impact, are included in Table 1, page 4, of DSS-1, and which ones are not included but requested in Case No. 2014–00003.

a. If the DSM programs are different, explain in detail how, including the impact on capacity requirements going forward?

b. If Case No. 2014 -00003 includes an additional capacity impact on the Companies' generation requirement going forward, should it not be included in this application?

A-50. Both the Commercial New Construction and Automated Demand Response Programs are included in the DSM line of Table 1, page 4, Exhibit DSS-1 and in Case No. 2014-00003 filing. The Automated Demand Response is part of the Commercial Load Management and demand impacts can be found at Case No. 2014-00003, Exhibit MEH-1, page 22. The Commercial New Construction is being included in the Commercial Conservation Program portion of Case No. 2014-00003, Exhibit MEH-1, page 31.

a. Case No. 2014-0003 includes no additional capacity impact not already described in Table 1, page 4, of Exhibit DSS-1.

b. See the response to subpart (a).

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Question No. 51

Witness: David S. Sinclair

Q-51. Reference DSS-1 at page 9. Provide any and all information that the Companies received from HIS Global Insight.

A-51. See the response to Question No. 13.

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Question No. 52

Witnesses: David S. Sinclair / Edwin R. Staton

Q-52. Reference DSS-1 in general and at page 11 in particular which has the following paragraph:

"Because of EPA's proposed New Source Performance Standards ("NSPS") for GHG, natural gas has become the fuel of choice for new fossil generation. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. On the other hand, the impending nationwide retirement of coal units and the shift to NGCC units will increase the demand for natural gas and put upward pressure on prices. Additional upside price risk is associated with the possibility of regulations limiting the extraction of shale gas. To address this long-term natural gas price uncertainty, the Resource Assessment analysis considered three natural gas price scenarios."

Answer the following questions regarding this paragraph.

a. Confirm that Cane Run 7 is not expected to be fully operational until 2015. Explain in detail any denial;

b. Confirm that the capacity factor of Cane Run will be largely influenced by the price of natural gas, and thus could vary in the range of 65-95%. Explain in detail any denial;

c. Confirm that on a daily basis Cane Run 7 could consume in excess of 100,000 Mcf of gas. Explain in detail any denial;

d. Confirm that during the 12 months ending June 30, 2013, the highest day sendout for LG&E's local distribution company operations occurred on January 22, 2013, when the average temperature was about 21 degrees F (much colder weather would result in significantly higher usage). On that day total system gas sendout to all customers was about 396,000 Mcf. Explain in detail any denial;

e. Confirm that generally, gas sendout to residential customers can be estimated at about half of that amount. Explain in detail any denial;

f. Confirm that for the 12 months ending June 30, 2013, sales to residential customers totaled about 19,000,000 Mcf, or an average of about 52,000 Mcf/per day over the course of a year. Explain in detail any denial;

g. Provide the average sendout for LG&E's local distribution company operations from 1 January 2014 to date;

h. Provide the sales to residential customers from 1 January 2014 to date;

i. Confirm that the capacity factor of the proposed Green River NGCC will be largely influenced by the price of natural gas. Explain in detail any denial;

j. Provide, on a daily basis, the consumption in Mcf of the proposed Green River NGCC;

k. State whether the Companies can definitively assert that firm capacity for the proposed Green River NGCC can be guaranteed barring force majeure during its operation; and

l. State whether the United States conversion of its electric generation from coal to natural gas can be guaranteed to be met with currently planned infrastructure build-out.

A-52.

a. The statement is correct.

b. The capacity factor of Cane Run 7 will be largely influenced by the price of natural gas and coal. In the first several years of its operation, Cane Run 7's capacity factor could vary from 65% to 95% based on current forecasts of coal and natural gas prices.

c. The statement is correct.

d. The Companies confirm the information is correct.

e. The Companies confirm the information is correct.

f. The Companies confirm the information is correct.

g. The average daily gas sendout for LG&E’s local distribution company operations from January 1, 2014 through February 28, 2014 was about 312,000 Mcf.

h. The residential gas sales for January 1, 2014 through February 28, 2014 was about 9,000,000 Mcf.

i. The statement is correct. See the response to PSC 1-34.

j. On a daily basis Green River NGCC could consume in excess of 100,000 Mcf of gas.

k. The Companies have engaged in discussions with Texas Gas Transmission (“TGT”) and ANR Pipeline Company about the potential to procure firm gas transportation to serve Green River NGCC. Based on those conversations, the Companies are confident that adequate firm gas transportation can be acquired by the time the plant becomes operational.

l. The Companies do not have knowledge of the specific pipeline capacity requirements for the entirety of the United States.

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Question No. 53

Witness: David S. Sinclair

Q-53. Reference DSS-1 at page 17. Confirm that the Companies imputed a 10.5% ROE for 2013-2042 when running its modeling.

A-53. The statement is correct. See Table 11 at page 17 in Exhibit DSS-1.

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Question No. 54

Witness: David S. Sinclair

Q-54. Reference DSS-1 at page 17. Did the Companies conduct an RFP for the proposed Brown solar facility? If not, why not?

A-54. The RFP submitted in September 2012 did not limit responses to a particular technology. In fact, one party responded to this RFP with a solar proposal. If the recommendation to build the Brown Solar Facility is approved, the Companies will issue a subsequent RFP for the construction of the facility. This process is the same as the process that will be used for the Green River NGCC if this project is approved.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 55

Witness: David S. Sinclair

Q-55. Reference DSS-1 at page 12. Confirm that Table 7 contains the price inputs for the modeling process used by the Companies. Explain in detail any denial.

A-55. This statement is correct. A transportation cost was added to these prices to develop the delivered fuel prices used in the analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 56

Witness: David S. Sinclair

Q-56. Reference DSS-1 at page 12. State whether the low, mid, high prices at the Henry Hub for any year are based on any particular date during the year. If not, explain the answer in detail.

A-56. The Low, Mid, and High prices at the Henry Hub are annual average prices based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2012. The EIA forecast is a publicly available long-term projection of natural gas prices. The "Mid," "High," and "Low" case natural gas price forecasts are based on EIA's AEO 2012 "Reference," "Low Estimated Ultimate Recovery" ("high" price), and "High Technically Recoverable Resource" ("low" price) cases, respectively, which provides internally consistent alternative views of the path of development of the resource base.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 57

Witness: David S. Sinclair

Q-57. Confirm that the price for natural gas rose at the Henry Hub to $6.41 in January 2014. Explain in detail any denial.

A-57. According the Energy Information Administration's Natural Gas Weekly Update of March 6, 2014 using Natural Gas Intelligence's Daily Gas Price Index for Henry Hub, the daily settled price of March 5, 2014 for delivery on March 6, 2014 was $6.41/MMBtu. Also, the daily settled price of March 4, 2014 for delivery on March 5, 2014 was $7.90/MMBtu. However, it is important to note that it is not particularly informative to compare the actual natural gas price for a single trading day to a long-term forecast of annual average natural gas prices.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 58

Witness: David S. Sinclair

Q-58. Confirm that Table 7 does not indicate a price under the low, mid, or high price scenario of $6.41 until after the year 2020. Explain in detail any denial.

A-58. In the short-run (daily) gas market, weather conditions can have a significant impact on Henry Hub gas prices. The EIA long-term Henry Hub annual average price forecasts recognize that U.S. natural gas prices are determined largely by supply and demand conditions, but over time reflect the long-term marginal cost of production, with the alternatives reflecting low estimated ultimate recoverable resources ("High" price) and high technically recoverable resources ("Low" price) forecasts respectively. All of the scenarios anticipate rising marginal costs, and thereby rising long-term natural gas prices on a nominal basis, but vary in the rate of increase.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 59

Witness: David S. Sinclair

Q-59. Reference DSS-1 at page 30 whereat the document reads: "As mentioned previously, the Green River 2x1 alternative is more expensive than other alternatives only if there is never a GHG limitation on existing coal units and gas prices are at or above the Mid gas scenario." Confirm this statement remains true as of the date when the company provides its answer.

A-59. This statement is still true.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 60

Witness: David S. Sinclair

Q-60. Reference DSS-1 at page 33 whereat the document reads: "The Iteration 2 alternatives are listed in Table 26. The year the Green River 2x1 NGCC unit is commissioned is listed in the alternative's long and short name. All alternatives include the DSM Commercial New Construction ("CNC") program because Iteration 1 demonstrated that it reduced the cost of the Green River 2x1 alternative." Is the CNC included in Case No. 2014-00002? If not, please state why not.

A-60. See Exhibit DSS-1 at page 33. Beginning with Phase 2, Iteration 2, all alternatives included the CNC program because this program was demonstrated in a previous iteration to have a favorable impact on revenue requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 61

Witness: David S. Sinclair

Q-61. Reference DSS-1 at page 1 whereat the document indicates that the RFP was issued in September 2012. Reference also DSS-1 at page 44 whereat the Companies state: "Based on publicly available information in this filing, the implied installed costs of these solar facilities were much lower than either of the projects the Companies' were evaluating. A report from Electric Power Research Institute ("EPRI") also supported the view that solar panel costs were decreasing." Provide all information upon which the Companies relied that details the "much lower" installed costs.

A-61. See footnote 34 on page 44 in Exhibit DSS-1. In addition, see the response to PSC 1-19. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 62

Witness: David S. Sinclair

Q-62. Reference DSS-1 at page 57. Provide a Table for the 10MW Solar PV Facility similar to that which was provided in Table 39 for the Green River 2x1 NGCC Unit Capital Costs (Nominal Dollars, $M).

A-62. See the table below. The analysis assumes no transmission system upgrades will be required for this project. The total cost of the project is approximately $36 million in 2018 dollars.

Solar Capital Costs (Nominal Dollars, $M)

	2015	**2016**	**Total**
Generation	24.0	10.6	34.6
Transmission	-	-	-
Totals	24.0	10.6	34.6

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Question No. 63

Witness: John N. Voyles, Jr.

Q-63. Reference the testimony of Mr. Voyles at page 4. Explain why the Resource Assessment models an NGCC of 640 MW whereas the company requests authorization to build a 700 MW facility.

A-63. See the response to Question No. 47.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 64

Witness: David S. Sinclair

Q-64. Through the RFP process, did PPL receive any proposals for a nuclear power option?

a. If so, why was it removed from consideration during the phase screening process?

A-64. The Companies state that their parent company, PPL, is not an applicant to this case nor was it involved in the analysis and conclusions the Companies have presented. Having said that, the Companies did not receive any proposals for a nuclear power option in response to their RFP. See Appendix A in Section 6.1 of Exhibit DSS-1.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Question No. 65

Witness: David S. Sinclair

Q-65. Did PPL Consider building a nuclear facility?

a. If so, provide all analysis and data associated with the consideration of building a nuclear facility; and

b. If not, why was a nuclear facility not considered?

A-65. The Companies state that their parent company, PPL, is not an applicant to this case nor was it involved in the analysis and conclusions the Companies have presented. Having said that, the Companies did not consider building a nuclear facility. The Companies have a capacity need as soon as 2016 which increases by 2018 (the date that Green River NGCC will be on-line). The Companies do not believe that a greenfield nuclear project in Kentucky, even assuming existing state law was changed, could be developed to meet that need in a timely manner.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Question No. 66

Witness: David S. Sinclair

Q-66. Provide long-term weather forecasts used to predict annual MW output from the Brown facility.

A-66. The PVsyst solar modeling software was used to model the output of the Brown Solar Facility. See the response to Question No. 68.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Question No. 67

Witness: David S. Sinclair

Q-67. Provide data supporting any estimations regarding annual days of sunlight at the Brown facility location.

A-67. An Excel file containing hourly solar irradiance data from 1998 to 2009 was included in the response to PSC 1-22. The path and filename of the file is 02_Analysis\Phase3\Iteration3\SolarCon\20131001_SolarData_0073.xlsx. The solar irradiance data is contained in the "SolarData" worksheet.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Question No. 68

Witness: David S. Sinclair

Q-68. Based on daily actual weather since January 1, 2004, provide:

a. MW per month that could have been generated if the Brown facility had been operational at the time;

b. The number of days when power could not be generated due to lack of sunlight;

c. The number of days that power could have been generated along with estimated output for each day; and

d. Annual energy output of the Brown facility, had it been operating normally.

A-68. The Companies have not performed this analysis. However, the PVsyst solar modeling software, which is a widely utilized industry generation estimation tool, was used to model the output of the Brown Solar Facility. PVsyst applies hourly historic meteorological data that has been collected to estimate the production of a PV system, based on specific OEM module performance at site conditions.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Question No. 69

Witness: John N. Voyles, Jr.

Q-69. Provide the maintenance plans for the Brown facility, including:

a. Number of employees necessary for regular maintenance;

b. Number of hours employees will spend on regular maintenance both daily and annually; and

c. Descriptions for maintenance that will be specific to the operation of a solar facility as opposed to a coal-fired or Natural Gas facility.

A-69.

a. There are 66 full time KU employees, and 13 resident contractors that perform regular maintenance activity at the Brown site including maintenance for the coal-fired, combustion turbine and hydroelectric units located there.

b. The average straight time hours are 1,847 annually per employee. The average overtime hours worked annually per employee is 262.

c. Regular maintenance activities anticipated at this time for the solar facility will include electrical checks, invertor and relay maintenance, PV panel cleaning and grounds maintenance around the panel arrays.

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Response to the Attorney General's Initial Data Requests
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Question No. 70

Witness: John N. Voyles, Jr.

Q-70. Does PPL or LG&E, KU separately have a goal of reducing its carbon footprint? If so, what is the goal and how is this goal expected to be achieved?

A-70. No, the Companies do not have a specific goal for reducing their carbon footprint.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 71

Witness: David S. Sinclair

Q-71. Reference Sinclair testimony page 7, lines 14-20. Are there alternative, respected indicators of the Kentucky Economy?

a. Do any of those indicators show a shrinking or stagnate Kentucky economy and if so, why were these indicators not given more weight?

A-71. These economic indicators were utilized in various models because they were identified as having the best historical statistical relationship to the particular load variable that was being forecasted.

a. No.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 72

Witness: David S. Sinclair

Q-72. Reference Sinclair testimony page 7, line 20 – page 8, line 4. Are there alternative, respected indicators of the Kentucky population?

a. Do any of those indicators show a shrinking or stagnate Kentucky population and if so, why were these indicators not given more weight?

A-72. See the response to Question No. 71.

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KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 73

Witness: Gary H. Revlett

Q-73. Has the currently sitting President of the United States ever announced his intention to implement environmental regulations through EPA, but failed to promulgate those regulations?

a. If so, how many times; and

b. If so, please list all of the environmental regulations that were announced, but never proposed by EPA.

A-73. With respect to environmental regulations impacting the utility industry, President Obama has publicly announced his intentions to implement additional environmental regulations to control mercury emissions and reduce carbon (CO_2) emissions from the utility industry. He has directed the EPA to propose and promulgate regulations toward this effort.

The EPA proposes and promulgates regulations per the applicable statutes developed by Congress after the general public is provided a sufficient comment period. The promulgated regulations may follow the proposed regulations or may be altered in response to public comment.

The EPA has finalized the regulations controlling the utility industry's mercury emissions into the air and has proposed new water effluent discharge regulations controlling mercury in our wastewater. With respect to carbon emissions, EPA has proposed a carbon dioxide performance standard for new electric generating units and is scheduled to propose a standard for existing units in June. Thus EPA is moving forward to promulgate regulations in accordance with all directives from the sitting President.

a.-b. The Companies have not performed the type of analysis required by this question.

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Response to the Attorney General's Initial Data Requests
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Question No. 74

Witness: Gary H. Revlett

Q-74. Has the currently sitting President of the United States ever proposed environmental regulations from EPA that were not finalized?

a. If so, how many times; and

b. If so, please list all the environmental regulations that were proposed but not finalized by EPA.

A-74. With respect to the utility industry, President Obama has publicly announced his intentions to implement additional environmental regulations to control mercury emissions and reduce carbon (CO_2) emissions from the utility industry. The President has directed the EPA to propose and promulgate regulations toward this effort.

EPA is currently moving forward in an attempt to promulgate and finalize all regulations in accordance with the directives from the President.

a.-b. The Companies have not performed the type of analysis required by this question.

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Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 75

Witness: Gary H. Revlett

Q-75. Has the currently sitting President of the United States ever rescinded a proposed air regulation due to pressure from the business community?

a. If so, how many times; and

b. If so, please list all the rescinded proposed air regulations.

A-75. No, to our knowledge the current sitting President has not rescinded any air regulations.

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Response to the Attorney General's Initial Data Requests
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Question No. 76

Witness: David S. Sinclair

Q-76. Did PPL consider the implications of potential legislation instituting a cap and trade program for carbon?

a. If so, what were the results; and

b. If not, why not?

A-76. The Companies state that their parent company, PPL, is not an applicant in this case nor was it involved in the analysis and conclusions the Companies have presented. Having said that, the Companies state that as discussed in Mr. Sinclair's testimony, on page 24, lines 1-7, the Companies used a price per ton of CO_2 emissions to reflect the impact of potential CO_2 regulations.

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Response to the Attorney General's Initial Data Requests
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Question No. 77

Witness: David S. Sinclair

Q-77. What evidence does the Company have that RECs will continue to be offered for the life of the proposed facilities?

A-77. The market for RECs is the result of various state laws that require their utilities to procure a certain amount of their energy from renewable resources or to provide a certified REC as an alternative as well as demand from individuals and organizations that seek to demonstrate their support for renewable energy by purchasing RECs. Therefore, the existence of REC markets in the future will depend on the continuing interest and support for renewable generating resources from these groups.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Question No. 78

Witness: David S. Sinclair

Q-78. Did the Company analyze any other estimates of price per ton of CO_2 besides that of a firm closely associated with environmental groups?

a. If so, what were the results; and

b. If not, why did the company rely on information from a group closely affiliated with national environmental organizations?

A-78. No.

a. Not applicable.

b. As demonstrated in Figure ES-1 of the Synapse report, their CO_2 price forecasts are consistent with the forecasts used by many utilities.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 79

Witness: David S. Sinclair

Q-79. Reference Resource Assessment page 44 stating "The price for solar RECs… was assumed to escalate at 2% per year." Please provide the analysis, data and reason for assuming this 2% annual increase.

A-79. For the purpose of this analysis, RECs were assumed to increase at the rate used to escalate O&M expenses.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 80

Witness: John N. Voyles, Jr.

Q-80. Reference Mr. Voyles' testimony page 5, lines 10-15. Provide the citation for the "setback requirements."

A-80. KRS 278.216 which incorporates by reference the setback requirements set forth in KRS 278.704.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 81

Witness: Gary H. Revlett

Q-81. Reference Mr. Voyles' testimony page 5, lines 5-11. What assumptions and evidence were used to reach the conclusion that the Companies will be allowed to "net out" the PSD requirements?

a. Provide all relevant documentation and citations supporting the Companies claim.

A-81. As stated in the PSD and Title V Permit Revision Application submitted by KU to the Kentucky Division for Air Quality in March 2014, the Green River NGCC project will trigger PSD requirements for CO, VOC, and greenhouse gases (GHG). PSD permitting is triggered for these pollutants because the emissions increases and net emissions increase, as defined in Kentucky Regulation 401 KAR 51:001, Section 1, is greater than PSD significance thresholds.

However, for NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, and sulfuric acid mist (SAM) the emissions increases associated with the project are calculated to be significant, but the net emissions increases/decreases are calculated to be less than significance thresholds. Therefore, PSD applicability for these pollutants is <u>not</u> triggered. A copy of the Permit Revision Application is attached.

Future emissions for proposed equipment to be constructed are calculated based on maximum equipment ratings and emission factors from EPA reference documents and vendor provided information. Past actual emissions, used to define the baseline actual emissions from existing emission units at the Green River Station, are calculated based on actual fuel usage data, continuous emissions monitoring system data, and emission factors from EPA reference documents and facility stack tests.

220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

March 3, 2014

Mr. Jim Morse
Kentucky Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601

RE: ***PSD and Title V Permit Revision Application***
Kentucky Utilities Company– Green River Generating Station
AI # 3228; Source I.D. # 21-177-00001; Title V Permit Number V-12-018

Dear Mr. Morse:

Kentucky Utilities Company (KU) owns and operates the Green River Generating Station (GRGS) in Muhlenberg County, Kentucky. This electrical generating facility is classified as a major source under the Title V operating permit program and currently operates in accordance with permit V-12-018. KU is hereby submitting the enclosed Prevention of Significant Deterioration (PSD) and Title V permit revision application to cover planned construction of a natural gas-fired combined cycle (NGCC) combustion turbine plant for the generation of electricity at the existing GRGS. The NGCC plant construction will coincide with the shutdown of the existing coal-fired boilers and miscellaneous equipment currently in service at GRGS. As discussed in the enclosed application, the proposed project will be subject to PSD air permitting requirements for certain pollutants.

We look forward to working in cooperation with KDAQ to help ensure the timely and successful completion of this permit action. Following your initial review of the application, if you or your staff have any questions, please do not hesitate contact Ms. Marlene Zeckner Pardee at (502) 627-2343 or Mr. Tony Schroeder of Trinity Consultants at (317) 451-8100.

Sincerely,

Steve Noland

Steve Noland
Manager, Environmental Air Section

Enclosure

cc: Ms. Marlene Zeckner Pardee, Kentucky Utilities Company
Mr. Paul J. Smith, P.E., Trinity Consultants
Mr. Tony Schroeder, CCM, Trinity Consultants

PSD AND TITLE V PERMIT REVISION APPLICATION

Kentucky Utilities Company/Green River Generating Station
> Central City, Kentucky

NGCC Combustion Turbine Plant

Prepared By:

TRINITY CONSULTANTS
1717 Dixie Highway
Suite 900
Covington, KY 41011
(859) 341-8100

March 2014

Project 131801.0073

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1. EXECUTIVE SUMMARY

Kentucky Utilities Company/Green River Generating Station (KU/GRGS) plans to construct a natural gas-fired combined cycle combustion turbine plant (NGCC plant) for the generation of electricity at the existing GRGS in Central City, Kentucky. The shutdown of the existing coal-fired boilers and miscellaneous equipment currently in service at GRGS will occur before the NGCC plant commences operation. As described in this application, the proposed project will be subject to Prevention of Significant Deterioration (PSD) air permitting requirements for certain pollutants.

1.1. PROJECT DESCRIPTION

The proposed NGCC plant will have a nominal net output of approximately 800 to 900 MW (depending on the combustion turbine option selected) and will consist of a 2x1 power block [two (2) combustion turbines and one (1) steam turbine] and ancillary equipment required to produce steam for the generation of electricity. Construction of the NGCC plant is anticipated to begin in 2015, with commercial operation set to begin in 2018. The proposed NGCC plant will include the following emission units to be installed at GRGS:

- Two (2) natural gas-fired combustion turbines (G- or H-class turbines, to be selected from several potential vendor/model options)
- One (1) steam turbine
- One (1) 99.9 MMBtu/hr natural gas-fired auxiliary boiler
- One (1) mechanical draft cooling tower
- One (1) 1,006 brake horsepower (bhp) diesel emergency generator
- One (1) 542 bhp diesel fire pump engine
- Fuel gas heater with a maximum heat input capacity of 15.0 MMBtu/hr
- One (1) 660 gallon diesel tank
- One (1) 849 gallons diesel tank
- Two (2) 8,400 gallon lube oil tanks
- One (1) 12,050 gallon lube oil tank
- Lube oil demister vents
- Circuit breakers
- Fugitive components

1.2. AIR PERMITTING AND REGULATORY REQUIREMENTS

GRGS currently operates as a coal-fired power plant and is classified as a major source under the PSD program (401 KAR 51:017). With the addition of the proposed NGCC plant and shutdown of the coal-fired power plant, GRGS will remain a PSD major source because potential emissions of at least one pollutant will still exceed the major source threshold of 100 tons per year (tpy). PSD permitting is therefore required for pollutants whose emission increases due to the project exceed the applicable PSD Significant Emission Rate (SER). Net emission increases of carbon monoxide (CO) and volatile organic compounds (VOC) due to the proposed project will exceed the applicable SERs, and thus PSD program elements are addressed in this application for these pollutants. In addition, net emission increases of greenhouse gases (GHGs) in carbon dioxide equivalents (CO_2e) will exceed 75,000 tpy, making them subject to regulation as a regulated New Source Review (NSR) pollutant with a SER of 0 tpy.[1] Since the net emission increases of GHGs on a mass basis exceed 0 tpy, the project also triggers PSD program elements for GHGs. Net emission increases of nitrogen oxides (NO_X), particulate matter

[1] "Subject to regulation" is defined in 401 KAR 51:001 Section 1(231), which cross references the federal definition in 40 CFR 51.166(b)(48).

(PM), particulate matter less than 10 and 2.5 microns in aerodynamic diameter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and lead (Pb) due to the project will not exceed the applicable SERs.

Emission units associated with the proposed project will be subject to applicable requirements of New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and Kentucky Administrative Regulations (KAR). As a result of the changes in the source-wide potential to emit (PTE) associated with the proposed project, GRGS will become a minor (i.e., area) source for hazardous air pollutants (HAP); therefore, only area source NESHAP requirements will be applicable to new emission units.

KU is submitting this construction permit application in accordance with all federal and state specific requirements.

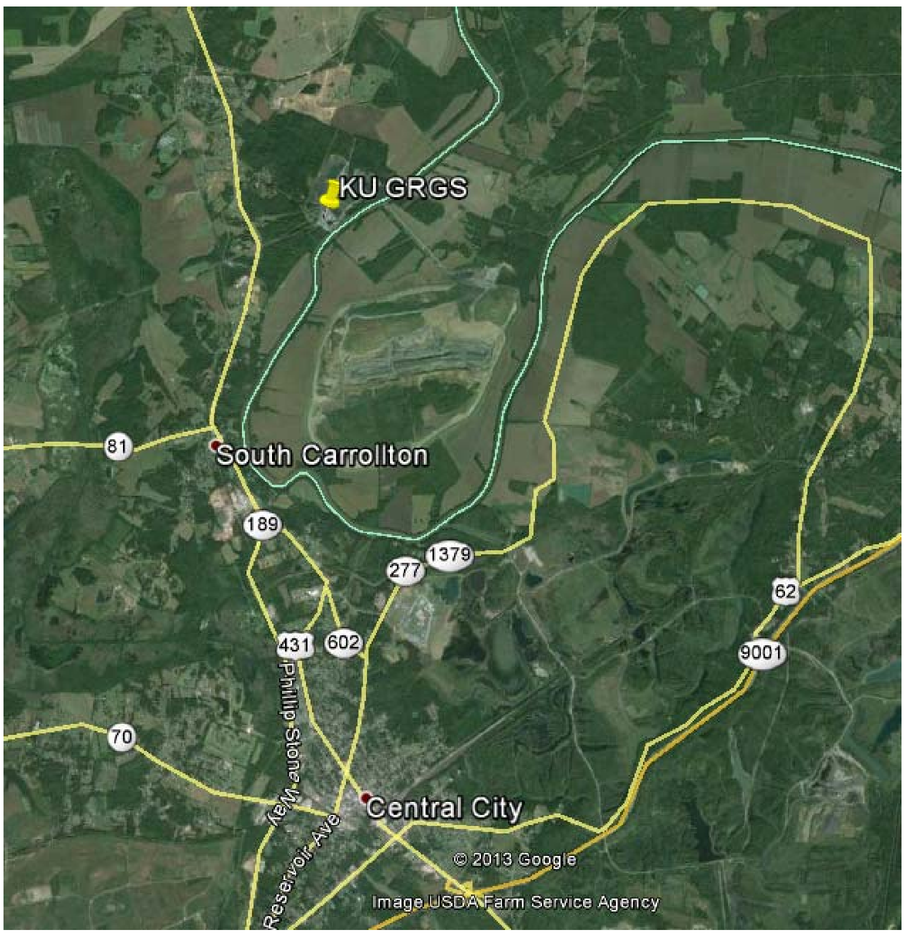
2. SOURCE & PROJECT DESCRIPTION

2.1. SOURCE DESCRIPTION

GRGS currently operates under Permit V-12-018, issued by the Kentucky Division for Air Quality (KDAQ) on November 12, 2013. GRGS includes two coal-fired utility boilers and miscellaneous equipment and is located in Central City, Kentucky, in Muhlenberg County. Muhlenberg County has been designated by the United States Environmental Protection Agency (U.S. EPA) as "attainment" or "unclassifiable" for all criteria pollutants.[2]

A site plot plan illustrating the layout of GRGS is included in Appendix A. An aerial photograph showing the location of the facility relative to the surrounding area is shown in Figure 2-1.

Figure 2-1. Green River Generating Station Area Map



2.2. PROJECT DESCRIPTION

KU plans to construct a NGCC plant with a nominal net output of approximately 800 to 900 MW (depending on the combustion turbine option selected). The plant will consist of a 2x1 power block [two (2) combustion turbines and one (1) steam turbine] and ancillary equipment required to produce steam for the generation of

[2] 40 CFR 81.318

electricity. Construction of the NGCC plant is anticipated to begin in 2015, with commercial operation set to begin in 2018. The shutdown of the existing coal-fired boilers and miscellaneous equipment currently in service at GRGS will occur before the NGCC plant commences operation.

2.3. PROPOSED EMISSION UNITS

The proposed NGCC plant will include the following emission units to be installed at GRGS:

- Two (2) natural gas-fired combustion turbines, (G- or H-class turbines, to be selected from several potential vendor/model options)
- One (1) steam turbine
- One (1) 99.9 MMBtu/hr natural gas-fired auxiliary boiler
- One (1) mechanical draft cooling tower
- One (1) 1,006 brake horsepower (bhp) diesel emergency generator
- One (1) 542 bhp diesel fire pump engine
- Fuel gas heater with a maximum heat input capacity of 15.0 MMBtu/hr
- One (1) 660 gallon diesel tank
- One (1) 849 gallons diesel tank
- Two (2) 8,400 gallon lube oil tanks
- One (1) 12,050 gallon lube oil tank
- Lube oil demister vents
- Circuit breakers
- Fugitive components

A process flow diagram is included in Appendix A. DEP7007 series application forms, which provide additional specifications and technical detail on the emission units, are included in Appendix B. Although preliminary engineering has been completed to a degree sufficient to define emission units and control technologies, because final selections have not yet been made for all equipment vendors, references to specific equipment vendors/models should be viewed as preliminary.

2.3.1. Combustion Turbines

The specific vendor and model of the combustion turbines to be installed will not be finalized until a later phase of the project. In order to initiate the air permitting process prior to final selection, the permit application incorporates each of the three potential combustion turbine vendor/model options, hereafter referred to as Options A, B, and C.

The maximum heat input of each combustion turbine will differ depending on the operating season and turbine vendor/model selected. Table 2-1 summarizes the maximum heat input values for each combustion turbine option during the worst-case operating scenario as well as the nominal plant net output associated with each option:

Table 2-1. Combustion Turbine Maximum Heat Input & Plant Net Output

Combustion Turbine Option	Combustion Turbines Maximum Heat Input[a] (MMBtu/hr)	Nominal Plant Net Output[b] (MW)
Option A	5,164	798
Option B	5,736	868
Option C	5,804	881

a. Maximum heat input capacity is for 2 combustion turbines.
b. Nominal plant net output based on new and clean equipment conditions.

Each combustion turbine will be equipped with an oxidation catalyst. The oxidation catalyst will control emissions of CO, VOC, and formaldehyde with a nominal control efficiency during normal operation of 80 percent for CO, and 50 percent for VOC and formaldehyde. The nominal control efficiency during startup and shutdown events is 50 percent for CO and 20 percent for VOC.

Each combustion turbine will employ a low NO_X combustion system and if required may be furnished with selective catalytic reduction (SCR) for the reduction of NO_X emissions.

Each combustion turbine will experience a number of startup and shutdown events throughout the year. Startup events are classified as cold start, warm start, or hot start events, depending on the number of hours since the unit was last fired. Downtime required between startups relates to the metal temperature of the combustion turbines, steam turbine, and other equipment. Table 2-2 includes information on the expected number of each type startup and shutdown event.

Table 2-2. Projected Startup and Shutdown Events

Event Type	Definition	Baseload Dispatch Annual Events	Midrange Dispatch Annual Events
Hot Start	Startup <10 hr from shutdown	0	208
Warm Start	Startup >10 hr and <60 hr from shutdown	0	52
Cold Start	Startup >60 hr from shutdown	2	0
Shutdown	-	2	260

The combustion turbine generators will be periodically purged for maintenance purposes using carbon dioxide (CO_2) gas. GHG emissions associated with this maintenance activity are accounted for in the emission calculations.

2.3.2. Steam Turbine

The steam turbine will be powered by steam generated within the heat recovery steam generators (HRSGs) using latent heat from each combustion turbine's exhaust gas. The steam turbine and HRSGs do not generate emissions during normal operation or startups and shutdowns. The steam turbine generator will be periodically purged for maintenance purposes using CO_2 gas and thus is still listed as an emission unit.

2.3.3. Auxiliary Boiler

A natural gas-fired steam boiler with a maximum heat input capacity of 99.9 MMBtu/hr will be used for auxiliary process steam. The boiler will utilize low NO_X burners with flue gas recirculation to minimize emissions.

2.3.4. Cooling Tower

A mechanical draft counter-flow cooling tower will be used to exhaust waste heat from the steam turbine condenser and auxiliary cooling system to the atmosphere. Cooling tower drift will be minimized to 0.001 percent of the design recirculation rate.

2.3.5. Emergency Generator & Fire Pump Engine

An emergency generator with a nominal engine output rating of 1,006 bhp and a fire pump engine with a nominal engine output rating of 542 bhp will be installed as part of the proposed project. Ultra low sulfur diesel (ULSD) with a maximum sulfur content of 0.0015 weight percent (15 ppm) will be used.

2.3.6. Fuel Gas Heater

A natural gas-fired fuel gas heater with a maximum heat input capacity of 15.0 MMBtu/hr will be used, when needed, to heat the natural gas that will be introduced to the combustion turbines. Although the fuel gas heater is not expected to operate continuously, potential emissions are calculated based on continuous operation (i.e., 8,760 hours per year) at full load to allow for maximum operational flexibility.

2.3.7. Storage Tanks

One 660 gallon diesel tank and one 849 gallon diesel tank will be used to store fuel for the emergency generator and fire pump engine. In addition, two 8,400 gallon lube oil tanks and one 12,050 gallons lube oil tank will be used to store lube oil for the combustion and steam turbines.

2.3.8. Lube Oil Demister Vents

Each combustion turbine and the steam turbine will be equipped with an internal lube oil storage and distribution system. A small quantity of lube oil present in the systems will be vaporized due to the high operating temperatures, potentially resulting in VOC emissions. Each turbine will be equipped with a demister system to avoid lube oil loss to the atmosphere to the maximum extent possible. However, a small quantity of lube oil may be emitted as VOC and/or $PM/PM_{10}/PM_{2.5}$ from the lube oil demister vents.

2.3.9. Circuit Breakers

Circuit breakers will be installed at each generator and within the switchyard located adjacent to the power block. Each circuit breaker will contain sulfur hexafluoride (SF_6), a GHG commonly used as a high voltage insulator and circuit-interrupting medium.

2.3.10. Fugitive Components

The valves, flanges, connectors, open-ended lines, and other components associated with equipment in natural gas service may exhibit leaks of methane (CH_4); these fugitive emissions are expected to be minimal.

2.4. SHUTDOWN OF EXISTING OPERATIONS

KU plans for the shutdown of the following existing emission units at GRGS before the NGCC plant commences operation, which will result in contemporaneous emission decreases, as discussed in Section 3:

- Boiler #4 (EU03)
- Boiler #5 (EU04)
- Coal Handling Operations (EU05)
- Two (2) 25,000 gallon No. 2 Fuel Oil Tanks
- Infrequent Evaporation of Boiler Cleaning Solution (insignificant activity)
- Infrequent Burning of *de minimis* Quantities of Used Oil (insignificant activity)

Several existing emission units will remain operational at GRGS, as listed below:

- One (1) Emergency Generator (EU08)
- One (1) 500 gallon Unleaded Gasoline Tank
- Various Lubricating Oil Tanks
- One (1) 300 gallon Kerosene Tank
- One (1) 300 gallon Diesel Tank
- One (1) 2,000 gallon Diesel Tank
- One (1) 1,000 gallon Diesel Tank
- Kerosene Heaters

Note that while the Kerosene Heaters were approved for construction/operation by KDAQ on September 20, 2011, and included in the February 2012 renewal application submitted by KU, the Kerosene Heaters were inadvertently excluded from the renewal permit recently issued by KDAQ. Therefore, the addition of the Kerosene Heaters to the revised permit through this permit action should not be considered the addition of a new insignificant activity.

Emissions from the existing emission units listed above are not discussed in Section 3 because these units will be unaffected by the proposed project.

3. EMISSION CALCULATIONS

GRGS is an existing major source under the PSD permitting program. With the addition of the proposed NGCC plant and shutdown of the coal-fired power plant, GRGS will remain a PSD major source because potential emissions of at least one pollutant will continue to exceed the major source threshold of 100 tpy. PSD permitting is therefore required for pollutants whose potential emission increases due to the project exceed the applicable PSD SER. Emission increases associated with the construction of new emission units must consider potential emission rates, whereas contemporaneous emission decreases associated with shutdown emission units must be quantified based on actual emissions during a baseline period.

This section addresses the methodologies used to quantify potential emission increases associated with the proposed project and contemporaneous emission decreases associated with the permanent shutdown of existing units at GRGS. Detailed emission calculations are included in Appendix C. PSD applicability is further discussed in Section 4.

3.1. PROJECT EMISSION INCREASES

3.1.1. Combustion Turbines

Natural gas combustion in the turbines will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, SAM, GHGs, and HAP. Potential emissions of regulated NSR pollutants are based on vendor emission guarantees during normal operation and vendor emission estimates during startups and shutdowns. Potential emissions of GHGs are based on methodologies in 40 CFR 98, Subpart C. Potential emissions of HAP during normal operation are based on reference emission factors in AP-42 and U.S. EPA's turbine MACT database, except for formaldehyde emissions, which are based on vendor emission estimates. HAP emissions during startups and shutdowns are calculated by assuming that their ratio to HAP emissions during normal operation is the same as the ratio between uncontrolled CO emissions during the worst-case (i.e., highest emissions) startup/shutdown event type to the worst-case (i.e., lowest) uncontrolled CO emission factor during normal operation.

Short-term emission rates during normal operation represent the worst-case scenario for PM, PM_{10}, $PM_{2.5}$, SO_2, SAM, and GHGs. Short-term emission rates during startup/shutdown represent the worst-case scenario for CO, NO_X, VOC, and HAP. Potential annual emissions are calculated for each pollutant based on the worst-case of either continuous normal operation or operation with maximum startups and shutdowns.

The combustion turbines will be periodically purged for maintenance purposes using CO_2 gas. Although it is expected that this will be required only once every 2 to 3 years, it is conservatively assumed that each turbine will be purged once per year. It is assumed that 100 percent of the purge gas is emitted to the atmosphere.

3.1.2. Steam Turbine

Similar to the combustion turbines, the steam turbine will be periodically purged for maintenance purposes using CO_2 gas. Although it is expected that this will be required only once every 2 to 3 years, it is conservatively assumed that the steam turbine will be purged once per year. It is assumed that 100 percent of the purge gas is emitted to the atmosphere.

3.1.3. Auxiliary Boiler

Combustion of natural gas in the auxiliary boiler will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, lead, GHGs, and HAP. Potential emissions of regulated NSR pollutants are based on vendor emissions data. Potential emissions of GHGs are based on methodologies in 40 CFR 98, Subpart C. Potential emissions of HAP are based on reference factors published in AP-42.

3.1.4. Cooling Tower

Cooling towers generate a small amount of PM emissions when water droplets evaporate, leaving the dissolved solids in the water as airborne PM. Potential PM emissions from the cooling tower are based on 0.0010 percent drift loss, the percent of drift mass governed by atmospheric dispersion, the cooling tower design maximum circulation rate, and total dissolved solids (TDS) for the cooling tower. PM_{10} and $PM_{2.5}$ emissions are calculated based on speciation of PM emissions as documented in the detailed emission calculations included in Appendix C.

3.1.5. Emergency Generator & Fire Pump Engine

The combustion of diesel fuel in the emergency generator and fire pump engines will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, GHGs, and HAP. Potential emissions of regulated NSR pollutants, except SO_2, are based on vendor emissions data. Potential emissions of SO_2 are based on a maximum fuel sulfur content of 15 parts per million (ppm) by weight as required by NSPS IIII. Potential emissions of GHGs are based on the methodologies in 40 CFR 98, Subpart C. Potential emissions of HAP are based on reference emission factors in AP-42.

3.1.6. Fuel Gas Heater

Combustion of natural gas in the fuel gas heater will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, lead, GHGs, and HAP. Potential emissions of regulated NSR pollutants are based on vendor emissions data. Potential emissions of GHGs are based on the methodologies in 40 CFR 98, Subpart C. Potential emissions of HAP are based on reference emission factors in AP-42.

3.1.7. Storage Tanks

AP-42 Section 7.1, *Organic Liquid Storage Tanks*, recommends use of U.S. EPA's TANKS 4.0 program to quantify potential VOC emissions associated with fixed-roof organic liquid storage tanks. TANKS 4.0 is based on the emission estimation procedures outlined in AP-42 Section 7.1 and uses chemical, meteorological, and tank-specific information to estimate emissions from standing and working losses.

The TANKS 4.0 program (version 4.09d) was used to calculate potential VOC and HAP emissions from the proposed diesel and lube oil storage tanks. The resulting TANKS output reports are included in Appendix C.

3.1.8. Lube Oil Demister Vents

Potential emissions of VOC and $PM/PM_{10}/PM_{2.5}$ from the lube oil demister vents associated with the combustion turbines and steam turbine are based on an engineering estimate of the vent lube oil emission rate. It is assumed that 100 percent of lube oil emitted from the demister vents is emitted to the atmosphere as VOC. In addition, it is assumed that 100 percent of lube oil emitted from the demister vents as VOC has the potential to condense, forming emissions of $PM/PM_{10}/PM_{2.5}$.

3.1.9. Circuit Breakers

Leaks from the circuit breakers will result in fugitive emissions of SF_6, a GHG commonly used as a high voltage insulator and circuit-interrupting medium. Potential GHG emissions are calculated based on the number of circuit breakers, amount of SF_6 in a full charge, and the SF_6 maximum annual leak rate proposed as BACT.

3.1.10. Fugitive Components

Leaks from the valves, flanges, connectors, open-ended lines, and other components associated with equipment in natural gas service will result in fugitive emissions of CH_4. Potential GHG emissions are calculated based on the number of each component type and U.S. EPA uncontrolled fugitive component emission factors.

3.2. CONTEMPORANEOUS EMISSION DECREASES

Contemporaneous emission decreases have been quantified from the shutdown of the existing coal-fired boilers at GRGS. Emission decreases from other existing emission units (e.g., coal handling operations) to be shut down are comparatively negligible and have conservatively been excluded from the calculation of contemporaneous emission decreases.

Contemporaneous emission decreases are calculated in accordance with the definition of baseline actual emissions in 401 KAR 51:001(20). For an existing electric utility steam generating unit, baseline actual emissions are determined based on any consecutive 24 month period selected by the owner or operator within the 5 year period immediately preceding the date actual construction of the proposed project begins. KU has selected the baseline period of November 2011 to October 2013 for all pollutants.

Baseline actual emissions from the coal-fired boilers were quantified based on a variety of data sources, including continuous emissions monitoring system (CEMS) data, stack test emission factors, AP-42 emission factors and particle size distributions, coal usage records, and No. 2 fuel oil usage records. In some cases, the baseline actual emissions calculated differ from actual emissions reported to KDAQ for the Kentucky emissions inventory system (KYEIS). Discrepancies are due to the following updates made in the calculation of baseline actual emissions for the current project:

- Quantified emissions of regulated NSR pollutants, HAP, and GHGs generated by the combustion of No. 2 fuel oil, where applicable.
- Revised SAM emission calculation methodology based on a study of SO_2 and sulfur trioxide (SO_3) emissions from coal-fired boilers at other KU facilities.
- Incorporated CH_4 and N_2O emissions, as calculated based on past actual fuel usages, in the quantification of CO_2e.

Additional information on baseline emission calculation methodologies can be found in Appendix C.

4. REGULATORY REQUIREMENTS

Emission units to be constructed as part of the proposed project will be subject to certain federal and state air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to emission units constructed as part of the NGCC plant.

4.1. NSR APPLICABILITY

The NSR permitting program generally requires a stationary source obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in emission increases in excess of certain threshold levels. The NSR program is comprised of two elements: Non-Attainment NSR (NNSR) and PSD. The NNSR program potentially applies to new construction or modifications that result in an emission increase of a pollutant for which the area in which the facility is located is classified as nonattainment. The PSD program applies to projects that result in an emission increase of a pollutant for which the area in which the facility is located is classified as attainment or unclassifiable.

4.1.1. Prevention of Significant Deterioration

GRGS is located in Muhlenberg County, which has been designated by the U.S. EPA as attainment or unclassifiable for all criteria pollutants. A source is considered major for PSD if it has the potential to emit either (1) 100 tpy or more of a regulated NSR pollutant if the source is classified as one of 28 designated industrial source categories, or (2) 250 tpy or more of any regulated NSR pollutant for sources in industrial categories not included on the “List of 28.” Fossil fuel-fired steam electric plants are on the “List of 28.” GRGS is considered a fossil fuel-fired steam electric plant for PSD purposes and has the potential to emit 100 tpy or more of a regulated NSR pollutant. Therefore, GRGS is a PSD major source.

PSD permitting is applicable to the proposed project if the net emission increase exceeds the PSD Significant Emission Rate (SER) for any regulated NSR pollutant. As shown in Table 4-1, net emission increases of CO, VOC, and CO_2e due to the proposed project exceed the applicable SERs. Therefore, PSD permitting requirements, including BACT and air quality modeling analyses, are required for these pollutants, as applicable.

Table 4-1. PSD Permitting Applicability

Pollutant	Net Emission Increase (Worst-case)[a] (tpy)	PSD Significant Emission Rate (tpy)	PSD Permitting Required (Worst-case)[a]?
NO_X	-534.7	40	No
CO	392.5	100	**Yes**
PM	-385.8	25	No
PM_{10}	-1,200.6	15	No
$PM_{2.5}$	-1,029.0	10	No
SO_2	-17,278.1	40	No
VOC	201.7	40	**Yes**
SAM	-169.9	7	No
Lead	-0.1	0.6	No
CO_2e	2,049,728	75,000[b]	**Yes**

a. Based on the worst-case turbine option on a pollutant-by-pollutant basis.
b. Along with other criteria, for a project that causes a 75,000 tpy increase in CO_2e emissions, GHGs become subject to regulation and are treated as a regulated NSR pollutant with a PSD SER of 0 tpy.

4.2. APPLICABLE NEW SOURCE PERFORMANCE STANDARDS

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions. An analysis of applicability for these rules is provided in the following subsections.

4.2.1. Subpart A - General Provisions

All NSPS-affected sources are subject to the general provisions of NSPS A unless specifically excluded by the applicable source-specific NSPS. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.2.2. Subpart Dc - Steam Generating Units

Pursuant to 40 CFR 60.40c(a), NSPS Dc applies to steam generating units constructed, modified, or reconstructed after June 9, 1989, with heat input equal to or greater than 10 MMBtu/hr but less than 100 MMBtu/hr. A steam generating unit is defined in 40 CFR 60.41c as a device that combusts any fuel that is used to heat an indirect heat transfer medium.

The proposed project will include an auxiliary boiler with a maximum heat input capacity of 99.9 MMBtu/hr and a fuel gas heater with a maximum heat input capacity of 15.0 MMBtu/hr. Both the auxiliary boiler and fuel gas heater will combust natural gas to heat an indirect heat transfer medium, thereby meeting the definition of steam generating units. Therefore, the auxiliary boiler and fuel gas heater will be subject to the applicable requirements of NSPS Dc. However, as units that only fire natural gas, neither of these units is subject to any emission standards under NSPS Dc, and the only applicable requirements from the rule are general recordkeeping and reporting requirements in 40 CFR 60.48c(g) and 40 CFR 60.48c(a). KU will comply with the applicable requirements of NSPS Dc as presented on the 7007V forms included in Appendix B.

4.2.3. Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

NSPS IIII applies to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in 40 CFR 60.4200(a). Per 40 CFR 60.4200(a)(2)(i), the provisions of NSPS IIII are applicable to owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE is (1) manufactured after April 1, 2006, and is not a fire pump engine, or (2) manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006. The proposed emergency generator and fire pump engines will be subject to the applicable requirements of NSPS IIII. KU will comply with the applicable requirements of NSPS IIII as presented on the 7007V forms included in Appendix B.

4.2.4. Subpart KKKK – Stationary Combustion Turbines

Pursuant to 40 CFR 60.4305(a), NSPS KKKK applies to combustion turbines constructed or modified after February 18, 2005, with a maximum heat input capacity equal to or greater than 10 MMBtu/hr (HHV). The proposed combustion turbines each have maximum heat input capacities greater than 10 MMBtu/hr. Therefore, the combustion turbines are subject to the applicable requirements of NSPS KKKK. KU will comply with the applicable requirements of NSPS KKKK as presented on the 7007V forms included in Appendix B.

4.3. NON-APPLICABLE NEW SOURCE PERFORMANCE STANDARDS

The following NSPS were evaluated for potential applicability and have been determined not to apply to the proposed project. KU requests that the following NSPS subparts be identified as non-applicable in the Statement of Basis.

- Subpart GG – Stationary Gas Turbines
- Subpart Kb – Volatile Organic Liquid Storage Vessels

A non-applicability determination for NSPS GG is provided because the non-applicability of this subpart is not readily apparent based on a simple review of the applicability criteria. A non-applicability determination is also provided for NSPS Kb.

4.3.1. Subpart GG – Stationary Gas Turbines

Pursuant to 40 CFR 60.330, NSPS GG applies to combustion turbines constructed, modified, or reconstructed after October 3, 1977, with heat input equal to or greater than 10 MMBtu/hr. NSPS GG has been supplanted by a newer subpart (i.e., subpart KKKK). Per 40 CFR 60.4305(b), units subject to NSPS KKKK are exempt from the requirements of NSPS GG. The proposed combustion turbines will be subject to the requirements of NSPS KKKK and are therefore exempt from NSPS GG.

4.3.2. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

Pursuant to 40 CFR 60.110b(a), NSPS Kb regulates storage vessels with a capacity greater than 19,813 gallons that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. The proposed lube oil and diesel storage tanks each have a capacity of less than 19,813 gallons. Therefore, the requirements of this rule do not apply.

4.4. APPLICABLE NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

NESHAP, federal regulations found in 40 CFR 61 and 63, are emission standards for HAP and are applicable to major sources (i.e., sources with a source-wide PTE for HAP emissions greater than 10 tpy of a single HAP or 25 tpy of total combined HAP) or area sources of HAP, as specified by each subpart. NESHAP apply to sources in specifically regulated industrial source classifications (Clean Air Act Section 112(d)) or on a case-by-case basis (Clean Air Act Section 112(g)) for facilities not regulated as a specific industrial source type. Pollutant specific NESHAP may also be applicable.

4.4.1. Subpart A – General Provisions

All affected sources are subject to the general provisions of Subpart A unless otherwise specified by the source-specific NESHAP. Subpart A generally requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.4.2. Subpart ZZZZ – Reciprocating Internal Combustion Engines

NESHAP ZZZZ establishes emission and operating limitations for HAP emitted from stationary RICE located at major and area sources of HAP emissions. The proposed emergency generator and fire pump engines will be subject to the RICE NESHAP per 40 CFR 63.6585. Pursuant to 40 CFR 63.6590(c)(1), new CI RICE located at an area source must meet the requirements of NESHAP ZZZZ by meeting the requirements of NSPS IIII, and no additional requirements under NESHAP ZZZZ apply to such engines. KU will comply with the requirements of NESHAP ZZZZ for the emergency generator and fire pump engines by complying with the applicable requirements of NSPS IIII.

4.5. NON-APPLICABLE NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The post-project source-wide PTE for HAP emissions at GRGS will not exceed 10 tpy of a single HAP or 25 tpy of total combined HAP. Therefore, the proposed emission units will not be subject to any major source NESHAPs. The following area source NESHAP was evaluated for potential applicability and has been determined not to apply to the proposed project. KU requests that the following NESHAP subpart be identified as non-applicable in the Statement of Basis.

- Subpart JJJJJJ – Industrial Boilers and Process Heaters at Area Sources

A non-applicability determination for NSPS JJJJJJ is provided because the non-applicability of this subpart is not readily apparent based on a simple review of the applicability criteria.

4.5.1. Subpart JJJJJJ – Industrial Boilers and Process Heaters at Area Sources

NESHAP JJJJJJ regulates industrial, commercial, and institutional boilers that are located at or part of an area source of HAP emissions. Pursuant to 40 CFR 63.11195(e), gas fired boilers as defined in the rule are not subject NESHAP JJJJJJ. The proposed auxiliary boiler meets the definition of a gas-fired boiler and is therefore not subject to the requirements of NESHAP JJJJJJ.

4.6. COMPLIANCE ASSURANCE MONITORING

Under 40 CFR 64, facilities are required to prepare and submit CAM plans for certain emission units with the initial or renewal Title V operating permit application. CAM plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed the major source thresholds under the Title V program unless such units meet a specified exemption. For an emission unit whose post-controlled emissions are greater than the major source thresholds (referred to as large PSEUs in the rule), a CAM plan is required to be submitted with the initial Title V operating permit application. For emission units whose post controlled emissions are less than the major source emission thresholds, a CAM plan is not required to be submitted until the first Title V permit renewal application.

Each NGCC combustion turbine has pre-controlled emissions greater than 100 tpy for NO_X per turbine. Combustion turbine Options A and C will utilize SCR to control NO_X emissions to meet the applicable NSPS KKKK NO_X emission limit. Pursuant to 40 CFR 64.2(b)(1)(i), CAM is not applicable to emission limits proposed by U.S. EPA under Section 111 or 112 of the Clean Air Act (CAA) after November 15, 1990. Because NSPS KKKK was proposed after November 15, 1990, CAM does not apply to the combustion turbines for NO_X.

Each NGCC combustion turbine has pre-controlled emissions greater than 100 tpy for CO per turbine and will utilize an oxidation catalyst to meet the applicable CO BACT limit; therefore, the combustion turbines will be subject to the requirements of CAM for CO. Because post-controlled emissions per turbine are greater than 100 tpy for CO for Options B and C, the combustion turbines may be classified as large PSEUs for CO, depending on the option selected, requiring the submittal of a CAM plan with the initial Title V operating permit application. Compliance with the CO BACT limit will be demonstrated by an initial performance test.[3] KU has included a CAM plan for the combustion turbines for CO in Appendix E.

Combustion turbine Option B has pre-controlled emissions greater than 100 tpy for VOC per turbine and will utilize an oxidation catalyst to meet the applicable VOC BACT limit; therefore, the combustion turbines will be subject to the requirements of CAM for VOC if Option B is selected. Because post-controlled emissions per turbine are greater than 100 tpy for VOC for Option B, the combustion turbines may be classified as large PSEUs for VOC, depending on the option selected, requiring the submittal of a CAM plan with the initial Title V operating permit application. Compliance with the VOC BACT limit will be demonstrated by an initial performance test. KU has included a CAM plan for the combustion turbines for VOC in Appendix E.

Combustion turbine Options A and C each have pre-controlled emissions less than 100 tpy for VOC per turbine. Therefore, the requirements of CAM will not be applicable to the combustion turbines for VOC if one of these turbine options is selected.

No other proposed emission unit requires the use of a control device to comply with an emission limit; therefore, the requirements of CAM are not applicable to any other proposed emission unit.

[3] In the preamble to NESHAP YYYY (69 FR 10525), U.S. EPA noted that CO CEMS technology is not adequate to reliably and accurately measure trace levels of CO; therefore, KU is not proposing CO CEMS to determine compliance with the proposed CO BACT limit.

4.7. RISK MANAGEMENT PROGRAM

The Risk Management Program (RMP) in Section 112(r) of the 1990 Clean Air Act amendments was established to prevent accidental releases of hazardous substances. Applicability of the RMP program is determined by comparing the quantity of each hazardous material stored in a vessel to the 112(r) threshold quantity.

The 112(r) threshold quantity for ammonia with a concentration of 20 percent or greater is 20,000 pounds. KU will comply with the requirements of RMP as applicable if ammonia with a concentration of 20 percent or greater is stored on-site in an amount exceeding the threshold quantity.

4.8. TITLE V OPERATING PERMIT PROGRAM

40 CFR 70 establishes the federal Title V operating permit program. Kentucky has incorporated the provisions of the federal Title V program in 401 KAR 52:020. The major source thresholds with respect to the Title V program are 10 tpy of a single HAP, 25 tpy of total combined HAP, 100 tpy of a criteria pollutant, or 100,000 tpy of GHGs, expressed as CO_2e.

GRGS is currently a Title V source. The post-project source-wide PTE will exceed the Title V major source thresholds for one or more criteria pollutants as well as GHGs. With this application, KU requests the Title V permit for GRGS be updated to reflect the proposed changes to the source.

4.9. ACID RAIN PROGRAM

The Acid Rain Program (ARP) found at 40 CFR 72-78 applies to utility units. A utility unit is defined as a unit owned or operated by a utility that serves a generator in any state that produces electricity for sale. The proposed combustion turbines will meet the definition of utility units and therefore will be subject to the ARP. The proposed auxiliary boiler does not provide steam that subsequently generates electricity; thus, it cannot generate electricity for sale and is not subject to the ARP. The ARP requires pollutant monitors and the possession of SO_2 allowances for each ton of SO_2 emitted. Possession of SO_2 allowances is not required until after the end of the year in which the SO_2 is emitted. KU will submit an ARP permit application under a separate cover to meet the requirements of this regulation.

4.10. STRATOSPHERIC OZONE PROTECTION REGULATIONS

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H of 40 CFR 82 are not applicable to GRGS. Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I or Class II ozone depleting substances. Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. All repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at GRGS will be completed by a certified technician.

4.11. CLEAN AIR INTERSTATE / CLEAN AIR TRANSPORT RULES

The Clean Air Interstate Rule (CAIR), incorporated in the Kentucky SIP at 401 KAR 51:210, 51:220, and 51:230, applies to utility units. Based on the applicability criteria of 401 KAR 51:210 Section 1, 401 KAR 51:220 Section 1, and 401 KAR 51:230 Section 1 for the CAIR NO_X (annual and ozone-season) and SO_2 trading programs, the proposed combustion turbines will be subject to CAIR since they will each serve a generator with nameplate capacity of more than 25 megawatt electrical (MWe) producing electricity for sale. On July 11, 2008, the D.C.

Circuit Court vacated CAIR in its entirety. On July 6, 2010, U.S. EPA proposed the Clean Air Transport Rule (CATR) to replace CAIR. CATR was finalized on July 6, 2011; however, in December 2011 the D.C. Circuit Court stayed CATR and re-instated CAIR until legal challenges to CATR could be resolved. KU will comply with the applicable requirements of CAIR as outlined in the forms included in Appendix B.

4.12. KENTUCKY STATE REGULATIONS

The Kentucky Administrative Regulations (KAR) includes air quality regulations applicable at the emission unit level (source specific) and facility level for stationary sources. The rules also contain requirements relating to construction and operating permits.

4.12.1. Good Engineering Practice Stack Height (401 KAR 50:042)

Stack height limitations are established in 401 KAR 50:042 to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The requirements of 401 KAR 50:042 apply to facilities that commenced construction after December 31, 1970, and to dispersion techniques implemented after that date. This rule specifies that the good engineering practice (GEP) stack height is the maximum allowable stack height a source may use in establishing its applicable state implementation plan (SIP) emission limitation. KU will comply with this regulation by building stacks that are at GEP stack height or lower.

4.12.2. New Indirect Heat Exchangers (401 KAR 59:015)

The requirements of 401 KAR 59:015 are applicable to indirect heat exchangers having a heat input capacity greater than 1 MMBtu/hr for which construction commenced on or after the classification date specified by 401 KAR 59:015 Section 1(3). The proposed auxiliary boiler and fuel gas heater meet the definition of indirect heat exchangers and will be constructed after the applicable classification dates. Pursuant to 401 KAR 59:015 Section 2(2), affected facilities under NSPS Dc subject to a specific emission standard are exempt from 401 KAR 59:015. Since the auxiliary boiler and fuel gas heater are not subject to emission standards under NSPS Dc, they both are still subject to the requirements of 401 KAR 59:015. Therefore, particulate and SO_2 emissions for these affected facilities are regulated under 401 KAR 59:015. KU will comply with the applicable requirements of 401 KAR 59:015 as presented on the 7007V forms included in Appendix B.

4.12.3. New Storage Vessels for Petroleum Liquids (401 KAR 59:050)

The requirements of 401 KAR 59:050 apply to each affected facility with a storage capacity less than 10,567 gallons commenced on or after July 24, 1984, which is located in any county that is designated attainment for ozone under 401 KAR 51:010 and is part of a major source of VOC emissions. An affected facility is defined as a storage vessel for petroleum liquids that has a storage capacity of greater than 580 gallons. Petroleum liquids is defined to exclude No. 2 fuel oil; therefore, Diesel Tanks #6 and #7 each do not meet the definition of an affected facility. Lube Oil Tanks #1, #2, and #3 each meet the definition of an affected facility, but Lube Oil Tank #3 has a capacity greater than 10,567 gallons and therefore does not meet the applicability criteria. Lube Oil Tanks #1 and #2 will be subject to the applicable requirements of the rule if combustion turbine Option B is selected, making GRGS a major source of VOC emissions. KU will comply with the applicable requirements of 401 KAR 59:050 as presented on the 7007V forms included in Appendix B.

4.12.4. Fugitive Emissions (401 KAR 63:010)

The requirements of 401 KAR 63:010 apply to fugitive dust emissions from roads, material handling, and storage operations. KU will comply with the requirements of this rule by taking reasonable precautions to prevent PM from becoming airborne and by ensuring that visible fugitive dust emissions do not escape beyond the property line.

4.12.5. Potentially Hazardous Matter or Toxic Substances (401 KAR 63:020)

The requirements of 401 KAR 63:020 apply to certain facilities that emit potentially hazardous matter or toxic substances that are not elsewhere subject to state regulations. GRGS has the potential to emit pollutants that meet the definition of "potentially hazardous matter or toxic substances" as defined in the rule. KU will not allow emissions of potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals, and plants. An air toxics dispersion modeling analysis was completed as part of this application and is included in Section 8.

5. BACT ANALYSIS METHODOLOGY

As the proposed project is expected to result in emission increases of certain pollutants in excess of the NSR major modification thresholds, an analysis to ensure the implementation of BACT is required for the new units being proposed as part of this project. A technical review has been performed to investigate and identify emission controls that have recently been determined by various permitting authorities across the U.S. to satisfy BACT requirements.

5.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations:

> *A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.*[4]

PSD BACT is defined in the relevant part as:

> *...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and Technologies, including fuel cleaning or treatment or innovative fuel combustion Technologies for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.*[5]
> [primary BACT definition]
>
> *If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*
> [allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

5.1.1. Emission Limitation

BACT is first and foremost an emission limitation, not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies to achieve the limit, the final result of BACT is an emission limit. Typically this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu HHV, ppm,

[4] 40 CFR 52.21(j)(2)
[5] 40 CFR 52.21(b)(12)

or lb/MW-hr).[6] The definition of BACT in 40 CFR 52.21(b)(12) does allow for the use of a work practice or operational standard where technological or economic limitations on the application of measurement methodology to a particular emission unit would make the imposition of an emission standard infeasible.

5.1.2. Each Pollutant

BACT is analyzed for each pollutant, not for a combination of pollutants, even where a technology may reduce emissions of more than one pollutant. This consideration is particularly important in performing cost analyses.

5.1.3. BACT Applies to the Proposed Source

Historical practice and court rulings have made it clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

Though BACT is based on the type of source proposed by the application, the applicant's ability to define the source is not absolute. As the U.S. EPA Environmental Appeals Board (EAB) stated in its decision upholding the Illinois EPA's (IEPA's) issuance of the permit for Prairie State Generating Station, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without altering that purpose.

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT...*
>
> * * *
>
> *[P]ermit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit..." For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.*[7]

In upholding the Prairie State decision, the Seventh Circuit Court of Appeals affirmed the substantial deference due the permitting authority in defining the portion of a project which BACT cannot redefine.[8] A description of the proposed project is included in Section 2.2.

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[6] Emission limits can be broadly differentiated as rate-based or mass-based. For a boiler, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).
[7] U.S. EPA Environmental Appeals Board. (2006, August 24). *In re: Prairie State Generating Company*. PSD Appeal No. 05-05.
[8] Seventh Circuit Court of Appeals. (2007, August 24). *Sierra Club v. EPA and Prairie State Generating Company LLC*. No. 06-3907.

5.1.4. Case-by-Case Basis

Unlike many Clean Air Act programs, the PSD program's BACT evaluation is done on a case-by-case basis. The EAB has recognized that PSD permit limits "...are not necessarily a direct translation of the lowest emission rate that has been achieved by a particular technology at another facility, but those limits must also reflect consideration of any practical difficulties associated with using the control technology."[9] U.S. EPA has explained how the top-down BACT analysis process works on a case-by-case basis.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.*[10]

To assist applicants and regulators with the case-by-case process, the U.S. EPA issued the draft *New Source Review Workshop Manual* (NSR Workshop Manual), which includes a "top-down" BACT analysis. U.S. EPA has developed a "top-down" process to ensure that a BACT analysis satisfies the applicable legal criteria. The five steps in a top-down BACT evaluation are summarized as follows:

- Step 1. Identify all possible control technologies.
- Step 2. Eliminate technically infeasible options.
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential.
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations.
- Step 5. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 5.1.1, the BACT limit is an emissions limitation and does not require the installation of any specific control device (though it may result in a limit prefaced upon using a specific control device).

5.1.5. Achievable

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."*[11]

U.S. EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on*

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[9] U.S. EPA Environmental Appeals Board. (2005, March 22). *In re: Cardinal FG*. PSD Appeal No. 04-04.
[10] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf
[11] U.S. Court of Appeals. (1999, March 2). *Sierra Club v. EPA.* No. 97-1686.

> *the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[12]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. Thus, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems, or technologies, as long as those considerations do not redefine the source.

5.1.6. Production Processes

The definition of BACT allows for the use of either production processes or control technologies as possible means for reducing emissions.

5.1.7. Available

The "availability" of a given control technology is assessed through a feasibility analysis. The analysis includes consideration of whether the control technology has been demonstrated as technologically feasible for the emission unit type in question or is commercially available and technologically feasible.

5.1.8. Floor

The least stringent emission rate allowable for BACT is any applicable emission limit under the NSPS (40 CFR 60) or NESHAP (40 CFR 61 and 63) rules. State SIP limitations must also be considered when determining the BACT limit floor.

5.2. BACT ASSESSMENT METHODOLOGY

BACT for the proposed project has been evaluated using the top-down approach, which includes the steps outlined in the following sections.

5.2.1. BACT Step 1 – Identification of Potential Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Control options include the application of alternate production processes and control methods, systems, and technologies including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question may also be considered. While identified

[12] U.S. EPA Environmental Appeals Board. (2005, December 21). *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04.

technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic, or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

The following resources are typically consulted when identifying potential control technologies for criteria pollutants:

- U.S. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database.
- Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies.
- Engineering experience with similar control applications.
- Information such as commercial guarantees provided by air pollution control equipment vendors with significant market share in the industry.
- Review of peer-reviewed literature from industrial technical or trade organizations.

5.2.2. BACT Step 2 - Elimination of Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question.

The first question in determining whether or not a technology is feasible is whether or not it has been demonstrated in practice. The term "demonstrated" means that the technology "has been installed and operated successfully elsewhere on a similar facility."[13] However, a technology that has been installed and operated successfully at one facility is not necessarily considered to be a demonstrated technology for another facility if the processes at the two facilities are distinctly different. The EAB addressed this issue in the court decision *In re: Cardinal FG Co.*, in which the EAB upheld a permitting agency's decision that a technology was not demonstrated.[14] The permitting authority reasoned that although a technology was in use at other facilities within the industry, it had not been widely adopted by facilities using the particular process to be installed at the proposed facility. The permitting authority was able to sufficiently distinguish the process at the proposed facility from the processes at other facilities using the technology in question and to explain the technical reasons why the technology would not work for the proposed source.

A technology that has not been demonstrated may be considered technically feasible if it is both "available" and "applicable" for the source type in question. A control technology is considered available only if it has reached the licensing and commercial sales phase of development and is thus considered to be "commercially available."[15] Control technologies still in the research and development (R&D) or pilot scale phases are not considered to be available. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.[16] Decisions about the applicability (i.e., technical feasibility) of an available control option include consideration of the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control technology.

As discussed in the *NSR Workshop Manual*:

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[13] U.S. EPA Environmental Appeals Board. (2006, August 24). *In re: Prairie State Generating Company*. PSD Appeal No. 05-05.
[14] U.S. EPA Environmental Appeals Board. (2005, March 22). *In re: Cardinal FG*. PSD Appeal No. 04-04.
[15] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf
[16] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

> *Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.*
>
> *For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.*[17]

The EAB has relied on the *NSR Workshop Manual* for decisions regarding the applicability of control technologies to specific source types. KU will utilize this guidance to eliminate technically infeasible control technology options.

5.2.3. BACT Step 3 – Ranking of Remaining Control Technologies

Technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

5.2.4. BACT Step 4 – Evaluation of Most Effective Controls

After identifying and ranking technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked control option from consideration, it is selected as the basis for the BACT limit. Alternatively, if unreasonable adverse economic, environmental, or energy impacts are associated with the top-ranked control option, the next most effective control option is evaluated. This process continues until an appropriate control technology is identified.

5.2.5. BACT Step 5 – Selection of BACT

In the final step of the BACT analysis, the BACT emission limit is determined for the emission unit under review based on evaluations from the previous steps.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. As discussed in Section 5.1.1, BACT is defined as an emission limit, unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

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[17] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

6. BACT ANALYSES

6.1. BACT REQUIREMENT

The BACT requirement applies to each new or modified emission unit from which there are emission increases of pollutants subject to PSD review. The proposed project is subject to PSD review for CO, VOC, and GHGs. Therefore, the requirements of BACT apply to each proposed emission unit with emissions of one or more of these pollutants.

6.2. PROPOSED PRIMARY BACT LIMITS SUMMARY

The proposed primary BACT limits are summarized in Table 6-1.

Table 6-1. Proposed Primary BACT Limits Summary

Emission Unit	Pollutant	Limit	Units	Averaging Period	Proposed BACT
Combustion Turbines[a]	CO	2.0	ppmvd @ 15% O_2	3-hr	Oxidation Catalyst
	VOC	2.0	ppmvd @ 15% O_2	3-hr	Oxidation Catalyst
	GHG	1,000	lb CO_2/MW-hr gross	12-month rolling	High Efficiency Design, Fuel Selection, Good Combustion, Operating, & Maintenance Practices
Steam Turbine	GHG	-	-	-	Work Practice
Auxiliary Boiler	CO	0.075	lb/MMBtu	3-hr	Good Design & Combustion Practices
	VOC	0.0055	lb/MMBtu	3-hr	Good Design & Combustion Practices
	GHG	51,199	tpy CO_2e	12-month rolling	Efficient Boiler Selection, Fuel Selection, & Good Combustion Practices
Emergency Generator[b]	CO	0.25	g/hp-hr	1-hr	Purchase of Engine Certified to Meet Emission Limit
	VOC	0.03	g/hp-hr	1-hr	Purchase of Engine Certified to Meet Emission Limit
	GHG	311	tpy CO_2e	12-month rolling	Fuel Usage Records and 40 CFR 98, Subpart C Factors
Fire Pump Engine	CO	0.67	g/hp-hr	1-hr	Purchase of Engine Certified to Meet Emission Limit
	VOC	0.09	g/hp-hr	1-hr	Purchase of Engine Certified to Meet Emission Limit
	GHG	145	tpy CO_2e	12-month rolling	Fuel Usage Records and 40 CFR 98, Subpart C Factors

Emission Unit	Pollutant	Limit	Units	Averaging Period	Proposed BACT
Fuel Gas Heater	CO	0.08	lb/MMBtu	3-hr	Good Design & Combustion Practices
	VOC	0.01	lb/MMBtu	3-hr	Good Design & Combustion Practices
	GHG	7,687	tpy CO_2e	12-month rolling	Fuel Selection & Good Combustion Practices
Storage Tanks	VOC	-	-	-	No BACT limit warranted based on trivial emissions
Lube Oil Demister Vents	VOC	-	-	-	No BACT limit warranted based on trivial emissions
Circuit Breakers	GHG	0.5	% leak rate	Annual	Good Design & Density Monitoring
Fugitive Components	GHG	-	-	-	No BACT limit warranted based on trivial emissions

a. Although the selection of some combustion turbine options would not result in the proposed project triggering PSD review for CO and/or VOC, for flexibility in turbine vendor/model selection, the BACT analysis is based on the worst-case scenario of triggering PSD review for both CO and VOC in addition to GHG.
b. Emissions data from emergency generator manufacturer is based on 100 percent load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

6.3. COMBUSTION TURBINES PRIMARY BACT ANALYSIS

Potentially applicable control technologies were identified by researching the U.S. EPA control technology database (i.e., RBLC), technical literature, control equipment vendor information, state permitting authority files, and based on process knowledge and engineering experience.

An RBLC database search was performed to identify control technologies and corresponding emission levels determined by permitting authorities as BACT within the past ten years. Process Code 15.210 (Large Combined Cycle & Cogeneration and Natural Gas-Fired Turbines) was used as the basis for the search. Search results are included in Appendix D.

6.3.1. Primary CO BACT Analysis

6.3.1.1. Background on Pollutant Formation

CO emissions are a byproduct of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.[18,19,20]

6.3.1.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for CO are included in Table 6-2.

[18] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[19] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[20] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

Table 6-2. Potential CO Control Technologies for Combustion Turbines

Pollutant	Control Technology
CO	Thermal Oxidizer
	EM_X/$SCONO_X$
	Oxidation Catalyst
	Good Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[21,22]

EM_X/$SCONO_X$

Goal Line Environmental Technologies developed $SCONO_X$ which can remove NO_X, CO, and VOC without supplemental reagent. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. EM_X uses a platinum-based catalyst coated with potassium carbonate to oxidize NO to NO_2, CO to CO_2, and hydrocarbons to CO_2 and water. NO_2 then absorbs onto the catalyst to form potassium nitrite and potassium nitrate. Periodically, the catalyst is regenerated with hydrogen gas that converts the compounds back to potassium carbonate, water, and nitrogen. To maintain continuous operation, the system is divided into sections, with one section offline at all times for regeneration.[23]

Oxidation Catalyst

CO emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the catalyst bed. Under optimum operating temperatures, this technology can achieve up to 90 percent reduction efficiency for CO emissions.[24]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[25]

Good Combustion Practices

Good combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize CO formation.

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[21] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[22] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[23] California EPA Air Resources Board. (2004, May). *Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts.* Retrieved from http://www.arb.ca.gov/research/apr/reports/l2069.pdf
[24] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[25] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf

6.3.1.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[26] Moreover, thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.[27]

The effectiveness of $EM_X/SCONO_X$ has not been demonstrated on NGCC plant-type operations. To date, this technology has only been implemented on smaller units, ranging from 5 MW to a maximum of 45 MW at the City of Redding Municipal Electric Plant.[28] As noted in the *NSR Workshop Manual*, "technologies which have not yet been applied to (or permitted for) full-scale operations need not be considered available; and the applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."[29] Since $EM_X/SCONO_X$ technology has not yet been demonstrated on large, commercial-scale combustion turbines, this technology is determined to be technically infeasible.

6.3.1.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-3.

Table 6-3. Efficiency of CO Control Technologies for Combustion Turbines

Pollutant	Control Technology	Control Efficiency (%)
CO	Oxidation Catalyst	80-90[a]
	Good Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.3.1.5. Evaluation of Most Effective Controls (Step 4)

The most stringent RBLC and permit entries for CO control are provided in Appendix D. The emission limits determined to constitute BACT for natural gas-fired combined cycle combustion turbines within the last 12 years vary both in emission levels and averaging periods. As shown in Appendix D, the majority of facilities with the most stringent CO BACT emission limits have installed oxidation catalysts for CO control. As such, KU will also achieve BACT through the use of an oxidation catalyst. Since this is the top level of control available, no further analysis is required.

6.3.1.6. Selection of BACT (Step 5)

The proposed combustion turbines are not subject to any NSPS or NESHAP standard for CO, and thus there is no floor of allowable CO BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the combustion turbines of 2.0 ppmvd at 15 percent oxygen (O_2) during normal operation at high loads, based on a 3-hour

[26] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[27] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)*. EPA-452/F-03-021. Retrieved from http://www.epa.gov/ttnchie1/mkb/documents/fregen.pdf
[28] California EPA Air Resources Board. (2004, May). *Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts*. Retrieved from http://www.arb.ca.gov/research/apr/reports/l2069.pdf
[29] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

averaging period. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable combustion turbines.[30] Compliance with the proposed limit will be demonstrated through an initial performance test.

6.3.2. Primary VOC BACT Analysis

6.3.2.1. Background on Pollutant Formation

VOC emissions are a byproduct of incomplete combustion. VOCs can encompass a wide spectrum of volatile organic compounds, some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents.[31]

6.3.2.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for VOC are included in Table 6-4.

Table 6-4. Potential VOC Control Technologies for Combustion Turbines

Pollutant	Control Technology
VOC	Thermal Oxidizer
	EM_X/$SCONO_X$
	Oxidation Catalyst
	Good Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[32,33]

EM_X/$SCONO_X$

Goal Line Environmental Technologies developed $SCONO_X$ which can remove NO_X, CO, and VOC without supplemental reagent. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. EM_X uses a platinum-based catalyst coated with potassium carbonate to oxidize NO to NO_2, CO to CO_2, and hydrocarbons to CO_2 and water. NO_2 then absorbs onto the catalyst to form potassium nitrite and potassium nitrate. Periodically, the catalyst is regenerated with hydrogen gas that converts the compounds back to potassium carbonate, water, and nitrogen. To maintain continuous operation, the system is divided into sections, with one section offline at all times for regeneration.[34]

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[30] One or more facilities included in the RBLC have NGCC combustion turbine CO limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate CO BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.
[31] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[32] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[33] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[34] California EPA Air Resources Board. (2004, May). *Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts*. Retrieved from http://www.arb.ca.gov/research/apr/reports/l2069.pdf

Oxidation Catalyst

VOC emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the catalyst bed. Under optimum operating temperatures, this technology can achieve 40 to 50 percent reduction efficiency for VOC emissions.[35,36]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[37]

Good Combustion Practices

Good combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize VOC formation.

6.3.2.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[38]

The effectiveness of EM_X/$SCONO_X$ has not been demonstrated on NGCC plant-type operations. To date, this technology has only been implemented on smaller units, ranging from 5 MW to a maximum of 45 MW at the City of Redding Municipal Electric Plant.[39] As noted in the *NSR Workshop Manual*, "technologies which have not yet been applied to (or permitted for) full-scale operations need not be considered available; and the applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."[40] Since EM_X/$SCONO_X$ technology has not yet been demonstrated on large, commercial-scale combustion turbines, this technology is determined to be technically infeasible.

6.3.2.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-5.

[35] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[36] California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf
[37] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
[38] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[39] California EPA Air Resources Board. (2004, May). *Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts*. Retrieved from http://www.arb.ca.gov/research/apr/reports/l2069.pdf
[40] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

Table 6-5. Efficiency of VOC Control Technologies for Combustion Turbines

Pollutant	Control Technology	Control Efficiency (%)
VOC	Oxidation Catalyst	40-50[a]
	Good Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.3.2.5. Evaluation of Most Effective Controls (Step 4)

The most stringent RBLC and permit entries for VOC control are provided in Appendix D. The emission limits determined to constitute BACT for natural gas-fired combined cycle combustion turbines within the last 10 years vary both in emission levels and averaging periods. As shown in Appendix D, the majority of facilities with the most stringent VOC BACT emission limits have installed oxidation catalysts for VOC control. KU will achieve BACT through the use of an oxidation catalyst. Since this is the top level of control available, no further analysis is required.

6.3.2.6. Selection of BACT (Step 5)

The proposed combustion turbines are not subject to any NSPS or NESHAP standard for VOC, and thus there is no floor of allowable VOC BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the combustion turbines of 2.0 ppmvd at 15 percent O_2 during normal operation at high loads, based on a 3-hour averaging period. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable combustion turbines.[41] Compliance with the proposed limit will be demonstrated through an initial performance test.

6.3.3. GHG BACT Analysis

6.3.3.1. Background on Pollutant Formation

The combustion of natural gas in the combustion turbines results in emissions of CO_2, CH_4, and N_2O. Nearly 100 percent of combustion-related GHG emissions are in the form of CO_2 on a mass basis. CH_4 and N_2O form as the result of incomplete combustion and are formed in much lower quantities.[42] Even when scaling CH_4 and N_2O by their relative global warming potentials (GWPs), these constituents combined contribute approximately one percent of the total GHG emissions (on a carbon dioxide equivalent [CO_2e] basis) resulting from the combustion of natural gas.

6.3.3.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for GHGs are included in Table 6-6.

[41] One or more facilities included in the RBLC have NGCC combustion turbine VOC limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate VOC BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.
[42] U.S. EPA. (1998, July). Natural Gas Combustion. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 1.4). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Table 6-6. Potential GHG Control Technologies for Combustion Turbines

Pollutant	Control Technology
GHG	Carbon Capture & Sequestration
	High Efficiency Design
	Fuel Selection
	Good Combustion, Operating, & Maintenance Practices

Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) involves separation and post-combustion capture of CO_2 emissions from combustion exhaust gases, pressurization of captured CO_2, transportation of captured CO_2, and injection and long-term geologic storage of the captured CO_2 or use of CO_2 in enhanced oil recovery (EOR).[43]

CO_2 Capture

In theory, carbon capture could be accomplished with low pressure scrubbing of CO_2 from an exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. Only solvents have been used to-date on a commercial (slipstream) scale. The use of solid sorbents and membranes is currently in the R&D phase.

CO_2 must be compressed from near-atmospheric pressure to pipeline pressure (around 2,000 psia) prior to transportation to an appropriate sequestration site. The compression of CO_2 requires a large auxiliary power load, resulting in the use of additional fuel (and additional CO_2 emissions) to generate the same amount of power.[44]

CO_2 Transport

CO_2 that has been captured and compressed is subsequently transported to the site designated for long-term geologic storage or use in EOR. Pipelines are expected to be the most economical and efficient method of transporting CO_2 for commercial purposes. Once constructed, pipelines reduce uncertainty associated with logistics, fuel costs, and reliance on other infrastructure that could increase the cost of CO_2 transportation. The history of transporting CO_2 via pipelines in the United States spans over 35 years. Approximately 55 million tons of CO_2 are transported through approximately 3,600 miles of CO_2-dedicated pipelines in the U.S. each year.[45] Currently there are no CO_2 pipelines in the vicinity of GRGS.

CO_2 Storage

CO_2 storage refers to the process of injecting CO_2 into subsurface formations for long-term sequestration.[46] CO_2 storage is currently happening across the U.S. and around the world. Large, commercial-scale projects, like the Sleipner CO_2 Storage Site in Norway, the Weyburn-Midale CO_2 Project in Canada, and the In Salah project in Algeria, have been injecting CO_2 for years. Each of these

[43] U.S. EPA. (2010, August). *Report of the Interagency Task Force on Carbon Capture and Storage.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[44] U.S. EPA. (2010, August). *Report of the Interagency Task Force on Carbon Capture and Storage.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[45] U.S. EPA. (2010, August). *Report of the Interagency Task Force on Carbon Capture and Storage.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[46] U.S. EPA. (2010, August). *Report of the Interagency Task Force on Carbon Capture and Storage.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

projects stores more than 1 million tons of CO_2 per year.[47] CO_2 may also be injected into the ground for EOR. Underground CO_2 injection has been used successfully to boost production efficiency of oil and gas by re-pressurizing the reservoir, and in the case of oil, by increasing mobility.[48]

The Midwest Geological Sequestration Consortium (MGSC), a regional partnership selected by the U.S. Department of Energy (DOE) as part of its Regional Carbon Sequestration Partnership (RCSP) initiative, is led by the Illinois, Indiana, and Kentucky State Geological Surveys and covers the entire state of Illinois, southwest Indiana, and western Kentucky. The partnership was established to assess carbon capture, transportation, and geologic carbon sequestration options in unminable coal seams, mature oil fields, and deep saline formations in the Illinois Basin. The MSGC has determined that the Illinois Basin's regional geology offers an optimal environment to safely and permanently store these emissions. MGSC has initiated a large-volume, saline reservoir sequestration test at the Archer Daniels Midland (ADM) Company's ethanol production facility (ADM plant) located in Decatur, Illinois. CO_2 injection was scheduled to begin at the ADM plant in February 2011 and continue for three years, with plans to inject approximately 1.1 million tons of supercritical CO_2 over the course of the project.[49] Although the injection of CO_2 for the ADM plant project is considered to be a development phase project only, KU has conservatively assumed that the Decatur, Illinois, site could be used to store CO_2 captured from the proposed combustion turbines. There are no other potential sites where CO_2 could be sequestered in the vicinity of GRGS. As shown in Table 6-7, apart from the ADM plant project, all active CO_2 storage projects in the region surrounding GRGS are in the preliminary stages of development (e.g., site characterization, permitting, well drilling, etc.).

Table 6-7. Currently Active CO_2 Capture & Storage Projects in Kentucky, Illinois, and Indiana

Project[a]	State(s)[a]	County[a]	Project Status[a]
An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins	IL, MI, KY, IN	Multiple	Site Characterization
ARI Eastern Shale CO_2 Injection Test	KY	Pike	Site Characterization
Cash Creek IGCC	KY	Henderson	Permitting
Duke Energy - Edwardsport Plant	IN	Knox	Permitting
FutureGen 2.0	IL	Morgan	Plant Design
Kentucky NewGas project	KY	Muhlenberg	Permitting
MGSC Development Phase - ADM Ethanol Facility	IL	Macon	Injection Ongoing
MGSC Validation Phase - Loudon Field[b]	IL	Fayette	Post-injection Monitoring
MGSC Validation Phase - Mumford Hills Field[b]	IN	Posey	Post-injection Monitoring
MGSC Validation Phase - Sugar Creek Field[b]	KY	Hopkins	Post-injection Monitoring
MGSC Validation Phase - Tanquary Site[b]	IL	Wabash	Injection Complete
MRCSP Validation Phase - Cincinnati Arch Test[b]	KY	Boone	Injection Complete
Western Kentucky CO_2 Test	KY	Hancock	Well Drilling

a. U.S. Department of Energy National Energy Technology Laboratory. Carbon Capture, Utilization, and Storage (CCUS) Database. Updated 1/2013.
b. MGSC validation phase projects consist of small-scale field testing of promising CO_2 sequestration opportunities.

[47] U.S. Department of Energy National Energy Technology Laboratory. (n.d.). *Carbon Storage FAQ Information Portal: Carbon Storage*. Retrieved from http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs
[48] U.S. Department of Energy National Energy Technology Laboratory. (n.d.). *Carbon Storage FAQ Information Portal: Carbon Storage*. Retrieved from http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs
[49] U.S. Department of Energy National Energy Technology Laboratory. (2010, July). *Midwest Geological Sequestration Consortium - Development Phase – Large Scale Field Test*. Project 678.

There are no potential sites where CO_2 could be used for EOR in the vicinity of GRGS, and there are currently no CO_2 pipelines which could transport compressed CO_2 to a region of the country (e.g., the Gulf Coast) where it could be used for EOR. Denbury Resources, a Texas company, had proposed to build a CO_2 pipeline from Rockport, Indiana, to Tinsley, Mississippi, where it would have linked up with other pipelines carrying CO_2 to oil fields along the Gulf Coast. The pipeline would have been fed by CO_2 from the Indiana Gasification, LLC (Indiana Gasification) plant in Rockport, Indiana.[50] Delays in the construction of Indiana Gasification's substitute natural gas and liquefied CO_2 production plant in Rockport have delayed construction of the CO_2 pipeline, which Denbury Resources has described as "not... a viable project" without the Indiana Gasification plant as a source of CO_2.[51] Based on the uncertainty surrounding the construction the Indiana Gasification plant, KU cannot assume it would be able to rely on use of the CO_2 pipeline planned by Denbury Resources to send compressed CO_2 to the Gulf Coast for use in EOR. KU would therefore need to assume the construction of a pipeline to Tinsley, Mississippi, would be required for the transport of CO_2 to a region where it could be used for EOR would be feasible.

High Efficiency Design

By utilizing a high efficiency natural gas-fired combined cycle combustion turbine system that meets the basic design purpose of the proposed project, less fossil fuels are required to generate the same desired output of electricity, thereby reducing GHG emissions. Advanced-class NGCC combustion turbines, such as those under consideration by KU, are considered be state-of-the-art in combustion turbine technology and efficiency.

Fuel Selection

Fuels containing less carbon have lower potential CO_2 and CH_4 emissions. The use of less carbonaceous fuels decreases CO_2 and CH_4 emissions as fewer carbon atoms are available. As shown in Table C-1 of 40 CFR 98, which includes CO_2 emission factors for a wide variety of industrial fuel types (in terms of kg/MMBtu), natural gas has the lowest carbon intensity of any available fuel for the combustion turbines.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices (GCPs) improve the fuel efficiency of the combustion turbines. GCPs include proper maintenance and tune-up of the combustion turbines at least annually according to manufacturer specifications. Specific GCPs applicable to combustion turbines are detailed in Table 6-8.

[50] Callahan, R. (2013, May 3). *Ind. Coal-gas bill stalls CO_2 pipeline project*. Associated Press.
[51] Marshall, C. (2013, May 3). *As Indiana gasification plant stalls, so does CO_2 pipeline*. E&E Publishing, LLC.

Table 6-8. Good Combustion, Operating, and Maintenance Practices for Combustion Turbines

Control Technique	Practice	Standard
Operator Practices	Documentation of operating procedures, updated as required for equipment or practice changes. Maintenance of operating logs/records.	Maintain written site-specific operating procedures in accordance with GCPs.
Maintenance Knowledge	Training on equipment & procedures, as applicable.	Equipment maintenance performed by personnel with training specific to equipment.
Maintenance Practices	Documentation of maintenance procedures, updated as required for equipment or practice change. Routinely scheduled inspections, with corrective actions taken as appropriate. Maintenance of logs/records.	Maintain site-specific procedures for optimum maintenance practices. Scheduled periodic inspections, with corrective actions taken as appropriate.
Fuel Quality Analysis & Fuel Handling	Monitoring of fuel quality. Maintenance of fuel quality certification from supplier, if needed. Periodic fuel sampling and analysis. Good fuel handling practices. Use of natural gas.	Fuel analysis, where composition may vary. Fuel handling procedures appropriate to fuel type.

6.3.3.3. Elimination of Technically Infeasible Options (Step 2)

CCS is an established process in some industry sectors but not in the power generation industry. Although CCS has been used on a small scale at a few coal-fired power plants to control CO_2 emissions on very small slipstreams, CCS has not been demonstrated to control full-stream emissions from power generation facilities. As noted in the *NSR Workshop Manual*, "technologies which have not yet been applied to (or permitted for) full-scale operations need not be considered available; and the applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."[52] CCS is therefore considered technically infeasible and does not meet the requirements of BACT.

Although CCS is considered technically infeasible and does not meet the requirements of BACT, KU has conservatively extended the BACT analysis for CCS to evaluate the associated environmental, energy, and economic impacts in Step 4.

6.3.3.4. Ranking of Remaining Control Technologies (Step 3)

KU proposes to implement all potential control technologies identified in Section 6.3.3.2 for the control of GHG emissions from the combustion turbines, with the exception of CCS, which is technically and economically infeasible, as discussed in Steps 2 and 4, respectively. Ranking potential control options is therefore unnecessary.

[52] U.S. EPA. (1990, October). *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft).* Retrieved from http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

6.3.3.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. For all identified potential control technologies except CCS, KU has not identified any adverse economic, environmental, or energy impacts.

Economic Impacts

As discussed in Section 6.3.3, CCS is considered technically infeasible for the proposed project. However, KU has conservatively extended the BACT analysis for CCS to evaluate the associated environmental, energy, and economic impacts.

KU has completed a cost feasibility analysis for the use of CCS for the control of CO_2 from the combustion turbines. The cost analysis is primarily based on cost factors obtained from the *Report of the Interagency Task Force on Carbon Capture and Storage (CCS Task Force Report)*.[53] The *CSS Task Force Report* identifies a range of costs associated with each component of CCS (i.e., CO_2 capture, transport, and storage). The cost analysis is conservatively based on the lowest applicable cost factors from the report for the capture and storage components of CCS.

CO_2 capture and compression costs vary widely depending on the type of combustion equipment and process used at a facility; the current analysis is based on factors for a new NGCC facility. CO_2 capture and compression costs typically use a CO_2-captured or CO_2-avoided basis. The CO_2-captured basis accounts for all CO_2 that is removed from the process as a result of the installation and use of a control technology, not including losses during transport and storage or emissions from the control technology itself. A CO_2-avoided basis takes into account CO_2 losses during transport and storage as well as CO_2 emissions from equipment associated with the implementation of the CCS system. The use of a CO_2-captured basis is appropriate for use in the current analysis because a BACT analysis is based on direct emissions from a source only (i.e., direct CO_2 emissions from the combustion turbines) and does not account for secondary emissions (e.g., CO_2 emissions generated during the process of compression). Therefore, the cost factor based on CO_2-captured was used.

Potential transport options for KU include building a pipeline to the site of the ADM plant project in Decatur, Illinois, where CO_2 would be injected underground for storage in geologic formations, or building a pipeline to Tinsley, Mississippi, to link up with existing pipelines sending CO_2 to the Gulf Coast region for use in EOR. The first option is assumed to be more cost feasible because, due to the relative proximity of Decatur, Illinois, to GRGS, a shorter pipeline would be required.[54] The length of pipeline required to reach the proposed storage site in Decatur, Illinois, is approximately 200 miles. The cost to construct, operate, and maintain a pipeline is estimated based cost calculations published by the U.S. Department of Energy National Energy Technology Laboratory.[55]

The CO_2 storage costs presented in the *CCS Task Force Report* vary widely. Although it may be an underestimate, the low end of the range is conservatively used as the CO_2 storage cost factor in the current analysis.

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[53] U.S. EPA. (2010, August). *Report of the Interagency Task Force on Carbon Capture and Storage.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[54] Although KU could conceivably generate revenue from the sale of CO_2 for use in EOR to assist in off-setting the cost of CO_2 capture and transport, a substantial amount of effort would been necessary to negotiate with oil and gas companies that may be able to use CO_2. Predictions of CO_2 demand are difficult to make, and the nature of oil well ownership is such that negotiations over the value of CO_2 would likely involve multiple parties.
[55] U.S. Department of Energy National Energy Technology Laboratory. (2010, March). *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs*. Retrieved from http://www.netl.doe.gov/File Library/Research/Energy Analysis/Publications/DOE-NETL-2010-1447-QGESSCarbonDioxideTransportStorageCosts.pdf

Adjusted cost factors and the total cost estimate for the implementation of CSS at GRGS are included in Table 6-9. The total amortized cost of CSS for the control of CO_2 from the combustion turbines is approximately $220 million per year. The capital cost for the proposed project is approximately $700 million, with an amortized capital cost of approximately $67 million per year, including operation and maintenance costs. Therefore, implementation of CCS will cost more than 3 times the project capital cost on an annual basis. This is well beyond the range of cost effectiveness for BACT. Detailed cost analysis calculations are included in Appendix D.

Table 6-9. CCS Cost Analysis for CO_2 Emissions from Combustion Turbines

CCS Component	Adjusted Cost Factor[a] ($/ton CO_2 Removed)	Basis
CO_2 Capture	93.58	CO_2 Captured
CO_2 Transport	9.08	CO_2 Transported per 200 miles of pipeline
CO_2 Storage	0.39	CO_2 Stored
Total	103.06	CO_2 Captured, Transported, and Stored

a. Adjusted to December 2013 dollars and short tons of CO_2.

For comparison, Table 6-10 summarizes the results of CCS cost analyses for the control of CO_2 emissions from NGCC combustion turbines at similar facilities as presented in recent PSD applications. CCS was deemed economically infeasible for each facility listed in the table. The cost per ton of CO_2 removed from the proposed combustion turbines is consistent with the cost per ton of CO_2 removed deemed economically infeasible at these facilities.

Table 6-10. CCS Cost Analyses Results for CO_2 Emissions at Similar Sources

Facility	$/ton CO_2 Removed
La Paloma Energy Center[a]	93.16
Energy Transfer	429.60
Calpine Energy Deer Park	126.58
Calpine Energy Pasadena	126.58
Apex Bethel Energy Center	187.71
Air Liquide	66.97

a. Units are in $/ton CO_2 avoided. Cost in $/ton CO_2 removed would be somewhat lower due to the exclusion of losses occurring during transport and storage and emissions from the control technology itself.

Environmental and Energy Impacts

The implementation of CCS may be associated with negative environmental and energy impacts. For instance, the use of CO_2 capture results in an energy penalty of approximately 15 percent in terms of net plant efficiency.[56] The implementation of CSS could therefore result in the use of significantly more natural gas to power the combustion turbines, with a corresponding increase in emissions of all natural gas combustion pollutants.

[56] U.S. Department of Energy National Energy Technology Laboratory. (2013, September). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (Revision 2a).

Based on the technical infeasibility of CCS and the negative economic, environmental, and energy impacts, CCS is eliminated from consideration in the evaluation of BACT for the control of GHG emissions from the proposed combustion turbines. KU will achieve BACT through the remaining control options of high efficiency design, fuel selection (natural gas only), and good combustion, operating, and maintenance practices.

6.3.3.6. Selection of BACT (Step 5)

The proposed combustion turbines are not subject to any NSPS or NESHAP standard for GHGs, and thus there is no floor of allowable GHG BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a GHG BACT limits for the combustion turbines of 1,000 lb/MW-hr gross, which will be achieved by selection of state-of-the-art, high efficiency advanced-class combustion turbines using natural gas only and by good combustion, operating, and maintenance practices. The proposed BACT limit is consistent with the emission limit proposed by U.S. EPA in the proposed NSPS TTTT for GHG emissions for electric utility generating units.[57] Compliance with the proposed BACT limit will be demonstrated based on an initial performance test conducted in accordance with the requirements of the final NSPS TTTT rule. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable combustion turbines.[58]

6.4. COMBUSTION TURBINES SECONDARY BACT ANALYSIS

Primary BACT limits for the combustion turbines reflect the level of emissions expected to be achievable during periods of normal operation. These emission limits are not necessarily appropriate during periods of startup and shutdown. During startups and shutdowns, the turbines do not operate at their maximum efficiency, resulting in increased emission rates for some pollutants due to lower fuel input and exhaust flow. Certain control devices are not effective during startup and shutdown due primarily to lower exhaust temperatures. For example, SCR and oxidation catalysts rely on chemical reactions that do not take place below certain temperature thresholds. This makes it infeasible for combustion turbines to comply with BACT limits that are based on a heat input rate or flue gas flow rate during normal operations.

The definition of BACT states that a BACT limit is one that, "on a case-by-case basis is determined to be achievable."[59] In the interest of establishing BACT limits that are "achievable" while still requiring a high degree of control during normal operations, KU is proposing secondary BACT limits for periods of startup and shutdown. The establishment of secondary BACT limits is consistent with the permitting approach used by agencies permitting other power generating facilities. The Prairie State Generating Company (Peabody), near Marissa, Illinois, was permitted using secondary BACT limits. The permit, issued April 28, 2005, by the IEPA, was appealed to the EAB for review.[60] The EAB supported with the IEPA's issuing of secondary BACT limits, stating:

> *…adoption of an alternate method during these periods [of startup and shutdown] "reflects Illinois EPA's experience with industrial boilers, which found that the rate-based compliance methodology of the NSPS[61] is problematic when applied to stringent BACT limits."… IEPA stated further that, "[w]ithout this provision*

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[57] 79 FR 1516. (2014, January 8).

[58] One or more facilities included in the RBLC have tpy GHG BACT limits. Because such limits are highly dependent on equipment capacity, tpy GHG BACT limits cannot be compared with the limit proposed by KU.

[59] 40 CFR 52.21(b)(12)

[60] U.S. EPA Environmental Appeals Board. (2006, August 24). *In re: Prairie State Generating Company*. PSD Appeal No. 05-05.

[61] Reference from quoted material states, "The Permit uses the NSPS's methodology as the primary method for determining compliance with the BACT limits at issue during periods that do not include startup or shutdown."

for an alternative compliance methodology, the BACT limits for SO_2 and NO_X could not be extended with the necessary confidence that compliance is reasonably achievable with the BACT limits."[62]

While this statement referred specifically to SO_2 and NO_X limits, the EAB concurred with IEPA's ruling on lb/hr BACT limits for CO during startups and shutdowns.[63]

KU has determined that secondary BACT limits are both justified and necessary to ensure that the proposed primary BACT limits are achievable. Proposed secondary BACT limits are summarized in Table 6-11. Compliance with these limits will be determined based on fuel usage records, manufacturer emissions data, and the number of startup and shutdown events.

Note that the source proposed by KU is a NGCC combustion turbine plant with a net plant output of approximately 800 to 900 MW. Selection of the combustion turbine vendor/model will depend in part on the specific MW rating that is deemed necessary to meet the energy demands of the project. This selection may or may not occur prior to the issuance of a revised permit for the proposed source. Because emissions from the combustion turbine options are not comparable due to the differences in turbine sizes (i.e., MW ratings), KU is proposing separate secondary BACT limits for each potential combustion turbine option. This is consistent with the approach taken by the Ohio EPA, Pennsylvania Department of Environmental Protection (DEP), and Texas Commission on Environmental Quality (TCEQ) in permitting recent, similar NGCC combustion turbine projects at the Oregon Clean Energy Center, Hickory Run Energy Station, and Pinecrest Energy Center, respectively.

Table 6-11. Secondary BACT Limits for Combustion Turbines

Combustion Turbine Option	Proposed Secondary VOC BACT Limit[a] (tpy)	Proposed Secondary CO BACT Limits[a] (tpy)	Proposed Secondary GHG BACT Limits[a] (tpy CO_2e)
Option A	51	150	2,664,908
Option B	212	468	2,960,582
Option C	65	372	2,994,410

a. Proposed limits are for 2 combustion turbines on a rolling, 12-month basis.

6.5. STEAM TURBINE BACT ANALYSIS

6.5.1. GHG BACT Analysis

During steam turbine maintenance shutdowns expected to occur no more than once per year, a very small volume of CO_2 stored on-site in gas cylinders or a tank will be required to purge air and hydrogen from the steam turbine generator casing. Since CO_2 is the only inert gas specified by the steam turbine generator manufacturer for safe purging of the combustible hydrogen gas inside the casing, no other purge gases are available for consideration. Therefore, the only available CO_2 control option for steam turbine generator purging is limiting the volume of purge gas used to the volume recommended by the manufacturer.

By limiting the purge gas volume to the level recommended by the manufacturer, CO_2 emissions will be insignificant. The implementation of work practices constituting good design and operating techniques

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[62] U.S. EPA Environmental Appeals Board. (2006, August 24). *In re: Prairie State Generating Company*. PSD Appeal No. 05-05.

[63] PSD Appeals No. 05-05, Section II.C.3 refers to the EAB determination on startup and shutdown BACT limits for CO.

consistent with manufacturer recommendations satisfies the requirement to establish BACT for this source of GHGs.

6.6. AUXILIARY BOILER BACT ANALYSIS

Potentially applicable control technologies were identified by researching the U.S. EPA control technology database (i.e., RBLC), technical literature, control equipment vendor information, state permitting authority files, and based on process knowledge and engineering experience.

An RBLC database search was performed to identify control technologies and corresponding emission levels determined by permitting authorities as BACT within the past ten years. Process Code 12.310 (Industrial-Size Boilers and Furnaces greater than 100 MMBtu/hr and less than 250 MMBtu/hr) was used as the basis for the search. Only natural gas-fired boilers were evaluated. Search results are included in Appendix D.

6.6.1. CO BACT Analysis

6.6.1.1. Background on Pollutant Formation

CO emissions are a byproduct of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.[64,65,66]

6.6.1.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for CO are included in Table 6-12.

Table 6-12. Potential CO Control Technologies for Auxiliary Boiler

Pollutant	Control Technology
CO	Thermal Oxidizer
	Oxidation Catalyst
	Good Design & Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[67,68]

[64] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[65] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[66] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[67] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[68] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

Oxidation Catalyst

CO emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the catalyst bed. Under optimum operating temperatures, this technology can achieve up to 90 percent reduction efficiency for CO emissions.[69]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[70]

Good Design & Combustion Practices

Good design and combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize CO formation.

6.6.1.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[71] Moreover, thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.[72]

6.6.1.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-13.

Table 6-13. Efficiency of CO Control Technologies for Auxiliary Boiler

Pollutant	Control Technology	Control Efficiency (%)
CO	Oxidation Catalyst	80-90[a]
	Good Design & Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.6.1.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option.

[69] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[70] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
[71] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[72] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)*. EPA-452/F-03-021. Retrieved from http://www.epa.gov/ttnchie1/mkb/documents/fregen.pdf

KU has completed a cost feasibility analysis for the use of an oxidation catalyst for the control of CO from the auxiliary boiler. As shown in Appendix D, based on vendor quotes and U.S. EPA Control Cost Manual equations, the annualized costs for an oxidation catalyst are more than $2,929 per ton of CO controlled. While cost effectiveness levels in this range may be deemed economically feasible under certain circumstances for other criteria pollutants, CO cost effectiveness is not directly comparable to other criteria pollutants. As evident via the NAAQS, CO has far less of a health impact at comparable ambient concentrations than other criteria pollutants. For example, the 1-hr NAAQS for CO is 40,000 micrograms per cubic meter ($\mu g/m^3$), more than 200 times higher than the next highest 1-hr average of 196 $\mu g/m^3$ for SO_2. The threshold for cost infeasibility for the control of CO emissions is therefore relatively low when compared to the cost infeasibility thresholds for other criteria pollutants. Therefore, an oxidation catalyst is eliminated as a control technology option. Detailed cost analysis calculations are included in Appendix D.

The only remaining control option is good design and combustion practices. A properly designed and operated boiler minimizes CO formation by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. KU will achieve BACT through the use of good design and combustion practices.

6.6.1.6. Selection of BACT (Step 5)

The proposed auxiliary boiler is not subject to any NSPS or NESHAP standard for CO, and thus there is no floor of allowable CO BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the auxiliary boiler of 0.075 lb/MMBtu on a 3-hour average basis. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable natural gas-fired boilers.[73] Compliance with the proposed limit will be based on an initial performance test conducted in accordance with U.S. EPA Method 10.

6.6.2. VOC BACT Analysis

6.6.2.1. Background on Pollutant Formation

VOC emissions are a byproduct of incomplete combustion. VOCs can encompass a wide spectrum of volatile organic compounds, some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents.[74]

6.6.2.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for VOC are included in Table 6-14.

[73] One or more facilities included in the RBLC have auxiliary boiler CO limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate CO BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.
[74] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf

Table 6-14. Potential VOC Control Technologies for Auxiliary Boiler

Pollutant	Control Technology
VOC	Thermal Oxidizer
	Oxidation Catalyst
	Good Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[75,76]

Oxidation Catalyst

VOC emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the catalyst bed. Under optimum operating temperatures, this technology can achieve 40 to 50 percent reduction efficiency for VOC emissions.[77,78]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[79]

Good Combustion Practices

Good combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize VOC formation.

6.6.2.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is also technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[80]

6.6.2.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-15.

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[75] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[76] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[77] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[78] California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf
[79] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
[80] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

Table 6-15. Efficiency of VOC Control Technologies for Auxiliary Boiler

Pollutant	Control Technology	Control Efficiency (%)
VOC	Oxidation Catalyst	40-50[a]
	Good Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.6.2.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option.

KU has completed a cost feasibility analysis for the use of an oxidation catalyst for the control of VOC from the auxiliary boiler. As shown in Appendix D, based on vendor quotes and U.S. EPA Control Cost Manual equations, the annualized costs for an oxidation catalyst are more than $71,694 per ton of VOC controlled. This is well beyond the range of cost effectiveness for BACT; therefore, an oxidation catalyst is eliminated as a control technology option. Detailed cost analysis calculations are included in Appendix D.

The only remaining control option is good design and operating practices. A properly designed and operated boiler minimizes VOC formation by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. KU will achieve BACT through the use of good design and operating practices.

6.6.2.6. Selection of BACT (Step 5)

The proposed auxiliary boiler is not subject to any NSPS or NESHAP standard for VOC, and thus there is no floor of allowable VOC BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the auxiliary boiler of 0.0055 lb/MMBtu on a 3-hour average basis. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable natural gas-fired boilers.[81] Compliance with the proposed limit will be based on an initial performance test conducted in accordance with U.S. EPA Method 25A.

6.6.3. GHG BACT Analysis

6.6.3.1. Background on Pollutant Formation

The combustion of natural gas results in emissions of CO_2, CH_4, and N_2O. Nearly 100 percent of combustion-related GHG emissions are in the form of CO_2 on a mass basis, since each carbon atom combusted in the fuel stream results in nearly one molecule of CO_2 emissions.[82] CH_4 and N_2O form as the result of incomplete combustion and are formed in much lower quantities. Even when scaling CH_4 and N_2O by their relative GWPs, these constituents combined contribute approximately one percent of the total GHG emissions (on a CO_2e basis) resulting from the combustion of natural gas.

[81] One or more facilities included in the RBLC have auxiliary boiler VOC limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate VOC BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.

[82] Although small fractions of fuel carbon convert to combustion byproducts such as CO and CH_4, the majority of carbon combusted in the fuel stream is converted to CO_2.

6.6.3.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for GHGs are included in Table 6-16.

Table 6-16. Potential GHG Control Technologies for Auxiliary Boiler

Pollutant	Control Technology
GHG	Carbon Capture and Sequestration (CCS) Efficient Boiler Selection Fuel Selection Good Combustion Practices

Carbon Capture and Sequestration

Refer to Section 6.3.3.2 for a description of CCS as a potential control technology for CO_2.

Efficient Boiler Selection

In general, boilers which operate at higher temperatures (i.e., larger boilers) have higher efficiencies. Increasing the efficiency of the boiler directly decreases GHG emissions as less fuel is combusted per unit output.

Fuel Selection

Fuels containing less carbon have lower potential CO_2 and CH_4 emissions. The use of less carbonaceous fuels decreases CO_2 and CH_4 emissions as fewer carbon atoms are available. As shown in Table C-1 of 40 CFR 98, which includes CO_2 emission factors for a wide variety of industrial fuel types (in terms of kg/MMBtu), natural gas has the lowest carbon intensity of any available fuel for the auxiliary boiler.

Good Combustion Practices

Good combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize VOC formation.

6.6.3.3. Elimination of Technically Infeasible Options (Step 2)

Refer to Section 6.3.3.3 for a discussion of the technical infeasibility of CCS as a potential control technology for CO_2.

6.6.3.4. Ranking of Remaining Control Technologies (Step 3)

KU proposes to implement all potential control technologies identified in Section 6.6.3.2 for the control of GHG emissions from the auxiliary boiler, with the exception of CCS, which is technically and economically infeasible. Ranking potential control options is therefore unnecessary.

6.6.3.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. For all identified potential control technologies except CCS, KU has not identified any adverse economic, environmental, or energy impacts.

Refer to Section 6.3.3.5 for a discussion of the adverse economic, environmental, and energy impacts of CCS. Based on the technical and economic infeasibility of CCS, it is eliminated as a potential control technology. KU will achieve BACT through efficient boiler selection, fuel selection (natural gas only), and good combustion practices.

6.6.3.6. Selection of BACT (Step 5)

The proposed auxiliary boiler is not subject to any NSPS or NESHAP standard for GHGs, and thus there is no floor of allowable GHG BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit of 51,199 tpy CO_2e on a rolling 12-month basis. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable natural gas-fired boilers.[83] Compliance will be demonstrated through the use of fuel usage records and emission factors obtained from 40 CFR 98, Subpart C.

6.7. EMERGENCY GENERATOR & FIRE PUMP ENGINE BACT ANALYSIS

Potentially applicable control technologies were identified by researching the U.S. EPA control technology database (i.e., RBLC), technical literature, control equipment vendor information, state permitting authority files, and based on process knowledge and engineering experience.

An RBLC database search was performed to identify control technologies and corresponding emission levels determined by permitting authorities as BACT within the past ten years. Process Code 17.110 (Large Diesel Internal Combustion Engines > 500 hp) was used as the basis for the search. Search results are included in Appendix D.

The RBLC results showed no add-on controls have been installed for emergency generators or fire pump engines. In the development of NSPS IIII, the U.S. EPA determined that for emergency ICE, the use of add-on controls could not be justified as the best demonstrated technology (BDT) due to the cost of the technology relative to the emission reduction that would be obtained.[84] Based on this determination, add-on controls have been excluded from this analysis on the basis of economic infeasibility.

6.7.1. CO BACT Analysis

The emergency generator will be subject to NSPS IIII limits for CO, setting the floor for allowable CO BACT limits. The applicable NSPS IIII limit for the emergency generator is 3.5 g/kW-hr (2.6 g/hp-hr). There are no applicable CO limits in NSPS IIII to set the BACT limit floor for the fire pump engine.[85] With no add-on controls available, the only effective methods of reducing CO emissions are the selection of fuel-efficient engines and the implementation of good combustion, operating, and maintenance practices to minimize CO emissions.

KU proposes the following CO BACT limits:

- For the emergency generator: 2.6 g/hp-hr on a 1-hour average basis,[86] and

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[83] One or more facilities included in the RBLC have tpy GHG BACT limits. Because such limits are highly dependent on equipment capacity, tpy GHG BACT limits cannot be compared with the limit proposed by KU.

[84] 70 FR 39874. (2005, July 11).

[85] Pursuant to 40 CFR 60.4205(c), the fire pump engine (which has a displacement less than 30 liters per cylinder) is subject to the emission limits from Table 4 of Subpart IIII.

[86] Pursuant to 40 CFR 60.4205(b)(2), emergency generator engines (which have a displacement of less than 10 liters per cylinder) must meet the emissions and opacity standards specified in 40 CFR 89.112 and 40 CFR 89.113.

- For the fire pump engine: 0.7 g/hp-hr on a 1-hour average basis.

To comply with the proposed limits, KU will purchase engines certified by the manufacturer to meet these emissions levels. Based on a review of the RBLC, KU believes that the proposed CO BACT limits are consistent with the most stringent limits for comparable emergency generators and fire pump engines.[87]

6.7.2. VOC BACT Analysis

The emergency generator and fire pump engine will be subject to NSPS IIII limits for VOC (i.e., non-methane hydrocarbons [NMHC]) and NO_X, setting the floor for allowable VOC BACT limits. The applicable NSPS IIII limit for the emergency generator is 6.4 g/kW-hr (4.8 g/hp-hr) on a 1-hour average basis for NMHC + NO_X. The applicable NSPS IIII limit for the fire pump engine is 4.0 g/kW-hr (3.0 g/hp-hr) on a 1-hour average basis for NMHC + NO_X. With no add-on controls available, the only effective methods of reducing VOC emissions are the selection of fuel-efficient engines and the implementation of good combustion, operating, and maintenance practices to minimize VOC emissions.

KU proposes the following VOC BACT limits:

- For the emergency generator: 0.03 g/hp-hr on a 1-hour average basis, and
- For the fire pump engine: 0.09 g/hp-hr on a 1-hour average basis.

To comply with the proposed limits, KU will purchase engines certified by the manufacturer to meet these emissions levels. Based on a review of the RBLC, KU believes that the proposed VOC BACT limits are consistent with the most stringent limits for comparable emergency generators and fire pump engines.[88]

6.7.3. GHG BACT Analysis

The emergency generator and fire pump engine are not subject to any NSPS or NESHAP standard for GHGs, and thus there is no floor of allowable GHG BACT limits. With no add-on controls available, the only effective methods of reducing GHG emissions are the selection of fuel-efficient engines and the implementation of good combustion, operating, and maintenance practices to minimize GHG emissions.

KU proposes a BACT limit of 456 tpy CO_2e on a rolling 12-month basis for the emergency generator and fire pump engine combined. Compliance will be demonstrated through the use of fuel usage records and emission factors obtained from 40 CFR 98, Subpart C. The proposed GHG BACT limit is consistent with what U.S. EPA has accepted as BACT for the Cricket Valley Energy Center project.[89] Based on review of the RBLC, KU believes that the proposed GHG BACT limit is consistent with the most stringent limits for comparable emergency generators and fire pump engines.[90]

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[87] One or more facilities included in the RBLC have emergency generator CO limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate CO BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.

[88] One or more facilities included in the RBLC have emergency generator VOC limits which are lower than the limits proposed by KU as BACT; however, these lower limits have been excluded from consideration in the determination of an appropriate VOC BACT limit for the reasons indicated in the explanatory notes in the RBLC tables included in Appendix D.

[89] Riva, S. (2011, July 29). *Re: EPA Comments on the Draft State Prevention of Significant Deterioration of Air Quality (PSD) Permit for the Cricket Valley Energy Center*. [Letter to Mr. Robert Stanton, Director, New York State Department of Environmental Conservation, Division of Air Resources]. Retrieved from http://www.epa.gov/nsr/ghgdocs/20110729CricketValleyEnergy.pdf

[90] One or more facilities included in the RBLC have tpy GHG BACT limits. Because such limits are highly dependent on equipment capacity, tpy GHG BACT limits cannot be compared with the limit proposed by KU.

6.8. FUEL GAS HEATER BACT ANALYSIS

Potentially applicable control technologies were identified by researching the U.S. EPA control technology database (i.e., RBLC), technical literature, control equipment vendor information, state permitting authority files, and based on process knowledge and engineering experience.

An RBLC database search was performed to identify control technologies and corresponding emission levels determined by permitting authorities as BACT within the past ten years. Process Code 13.310 (Natural Gas Fired Heater (<100 MMBtu/hr)) was used as the basis for the search. Search results are included in Appendix D.

6.8.1. CO BACT Analysis

6.8.1.1. Background on Pollutant Formation

CO emissions are a byproduct of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.[91,92,93]

6.8.1.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for CO are included in Table 6-17.

Table 6-17. Potential CO Control Technologies for Fuel Gas Heater

Pollutant	Control Technology
CO	Thermal Oxidizer
	Oxidation Catalyst
	Good Design & Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[94,95]

Oxidation Catalyst

CO emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the

[91] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[92] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[93] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[94] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[95] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

catalyst bed. Under optimum operating temperatures, this technology can achieve up to 90 percent reduction efficiency for CO emissions.[96]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[97]

Good Design & Combustion Practices

Good design and combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize CO formation.

6.8.1.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[98] Moreover, thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.[99]

6.8.1.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-18.

Table 6-18. Efficiency of CO Control Technologies for Fuel Gas Heater

Pollutant	Control Technology	Control Efficiency (%)
CO	Oxidation Catalyst	80-90[a]
	Good Design & Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.8.1.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option.

KU has completed a cost feasibility analysis for the use of an oxidation catalyst for the control of CO from the auxiliary boiler. As shown in Appendix D, based on vendor quotes and U.S. EPA Control Cost Manual equations, the annualized cost for an oxidation catalyst on the auxiliary boiler is $2,929 per ton of CO controlled. Potential CO emissions from the fuel gas heater are far less than potential CO emissions from the auxiliary boiler; therefore, the use of an oxidation catalyst for control of CO emissions from the fuel gas heater will be even more cost infeasible. Because an oxidation catalyst is beyond the range of cost effectiveness for BACT, it is eliminated

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[96] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[97] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
[98] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf
[99] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)*. EPA-452/F-03-021. Retrieved from http://www.epa.gov/ttnchie1/mkb/documents/fregen.pdf

as a control technology option. No additional add-on control technologies have been identified for the control of CO emissions from natural gas-fired fuel gas heaters.

The only remaining control option is good design and combustion practices. Properly designed and operated fuel gas heaters minimize CO formation by ensuring that temperature and oxygen availability are adequate for complete combustion. KU will achieve BACT through good design and combustion practices.

6.8.1.6. Selection of BACT (Step 5)

The proposed fuel gas heater is not subject to any NSPS or NESHAP standard for CO, and thus there is no floor of allowable CO BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the fuel gas heater of 0.08 lb/MMBtu on a 3-hour average basis. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable fuel gas heaters.

6.8.2. VOC BACT Analysis

6.8.2.1. Background on Pollutant Formation

VOC emissions are a byproduct of incomplete combustion. VOCs can encompass a wide spectrum of volatile organic compounds, some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents.[100]

6.8.2.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for VOC are included in Table 6-19.

Table 6-19. Potential VOC Control Technologies for Fuel Gas Heater

Pollutant	Control Technology
VOC	Thermal Oxidizer
	Oxidation Catalyst
	Good Design & Combustion Practices

Thermal Oxidizer (Recuperative and Regenerative)

Thermal oxidation is the process of increasing the temperature of the gas stream and maintaining an elevated temperature above the auto-ignition point for a sufficient period of time in order to oxidize pollutants.[101,102]

[100] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[101] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Incinerator – Recuperative Type)*. EPA-452/F-03-020. Retrieved from http://www.epa.gov/ttn/catc/dir1/frecup.pdf
[102] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

Oxidation Catalyst

VOC emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. The catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the emission stream passes through the catalyst bed. Under optimum operating temperatures, this technology can achieve 40 to 50 percent reduction efficiency for VOC emissions.[103,104]

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.[105]

Good Design & Combustion Practices

Good design and combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize VOC formation.

6.8.2.3. Elimination of Technically Infeasible Options (Step 2)

The use of a thermal oxidizer is also technically infeasible. Incinerators in general are not recommended for controlling gases with sulfur-containing compounds because of the formation of highly corrosive acid gases.[106]

6.8.2.4. Ranking of Remaining Control Technologies (Step 3)

The remaining control technologies are ranked in order of control efficiency in Table 6-20.

Table 6-20. Efficiency of VOC Control Technologies for Fuel Gas Heater

Pollutant	Control Technology	Control Efficiency (%)
VOC	Oxidation Catalyst	40-50[a]
	Good Design & Combustion Practices	Base Case

a. California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

6.8.2.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option.

KU has completed a cost feasibility analysis for the use of an oxidation catalyst for the control of VOC from the auxiliary boiler. As shown in Appendix D, based on vendor quotes and U.S. EPA Control Cost Manual equations, the annualized cost for an oxidation catalyst on the auxiliary boiler is $71,694 per ton of VOC controlled. Potential VOC emissions from the fuel gas heater are far less than potential VOC emissions from the auxiliary

[103] U.S. EPA. (2000, April). Stationary Gas Turbines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.1). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf
[104] California Air Resources Board. (1999, October 14). *Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production*. Retrieved from http://www.arb.ca.gov/energy/powerpl/appcfin.pdf
[105] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)*. EPA-452/F-03-018. Retrieved from http://www.epa.gov/ttn/catc/dir1/fcataly.pdf
[106] U.S. EPA. (n.d.). *Air Pollution Control Technology Fact Sheet (Thermal Incinerator)*. EPA-452/F-03-022. Retrieved from http://www.epa.gov/ttn/catc/dir1/fthermal.pdf

boiler; therefore, the use of an oxidation catalyst for control of VOC emissions from the fuel gas heater will be even more cost infeasible. Because an oxidation catalyst is beyond the range of cost effectiveness for BACT, it is eliminated as a control technology option. No additional add-on control technologies have been identified for the control of VOC emissions from natural gas-fired fuel gas heaters.

The only remaining control option is good design and combustion practices. Properly designed and operated fuel gas heaters minimize VOC formation by ensuring that temperature and oxygen availability are adequate for complete combustion. KU will achieve BACT through good design and combustion practices.

6.8.2.6. Selection of BACT (Step 5)

The proposed fuel gas heater is not subject to any NSPS or NESHAP standard for VOC, and thus there is no floor of allowable VOC BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit for the fuel gas heater of 0.01 lb/MMBtu on a 3-hour average basis. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable fuel gas heaters.

6.8.3. GHG BACT Analysis

6.8.3.1. Background on Pollutant Formation

The combustion of natural gas results in emissions of CO_2, CH_4, and N_2O. Nearly 100 percent of combustion-related GHG emissions are in the form of CO_2 on a mass basis, since each carbon atom combusted in the fuel stream results in nearly one molecule of CO_2 emissions.[107] CH_4 and N_2O form as the result of incomplete combustion and are formed in much lower quantities. Even when scaling CH_4 and N_2O by their relative GWPs, these constituents combined contribute approximately one percent of the total GHG emissions (on a CO_2e basis) resulting from the combustion of natural gas.

6.8.3.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for GHGs are included in Table 6-21.

Table 6-21. Potential GHG Control Technologies for Fuel Gas Heater

Pollutant	Control Technology
GHG	Carbon Capture and Sequestration (CCS) Fuel Selection Good Design & Combustion Practices

Carbon Capture and Sequestration

Refer to Section 6.3.3.2 for a description of CCS as a potential control technology for CO_2.

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[107] Although small fractions of fuel carbon convert to combustion byproducts such as CO and CH_4, the majority of carbon combusted in the fuel stream is converted to CO_2.

Fuel Selection

Fuels containing less carbon have lower potential CO_2 and CH_4 emissions. The use of less carbonaceous fuels decreases CO_2 and CH_4 emissions as fewer carbon atoms are available. As shown in Table C-1 of 40 CFR 98, which includes CO_2 emission factors for a wide variety of industrial fuel types (in terms of kg/MMBtu), natural gas has the lowest carbon intensity of any available fuel for the fuel gas heater.

Good Design & Combustion Practices

Good design and combustion practices include emission unit operation within the appropriate oxygen and temperature ranges to promote complete combustion and minimize VOC formation.

6.8.3.3. Elimination of Technically Infeasible Options (Step 2)

Refer to Section 6.3.3.3 for a discussion of the technical infeasibility of CCS as a potential control technology for CO_2.

6.8.3.4. Ranking of Remaining Control Technologies (Step 3)

KU proposes to implement all potential control technologies identified in Section 6.8.3.2 for the control of GHG emissions from the fuel gas heater, with the exception of CCS, which is technically and economically infeasible. Ranking potential control options is therefore unnecessary.

6.8.3.5. Evaluation of Most Effective Controls (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. For all identified potential control technologies except CCS, KU has not identified any adverse economic, environmental, or energy impacts.

Refer to Section 6.3.3.5 for a discussion of the adverse economic, environmental, and energy impacts of CCS. Based on the technical and economic infeasibility of CCS, it is eliminated as a potential control technology. KU will achieve BACT through fuel selection (natural gas only), and good combustion practices.

6.8.3.6. Selection of BACT (Step 5)

The proposed fuel gas heater is not subject to any NSPS or NESHAP standard for GHGs, and thus there is no floor of allowable GHG BACT limits. Based on a review of the emission limits achievable and the BACT determinations for other facilities provided in Appendix D, KU proposes a BACT limit of 7,687 tpy CO_2e on a rolling 12-month basis. Compliance will be demonstrated through the use of fuel usage records and emission factors obtained from 40 CFR 98, Subpart C. Based on a review of the RBLC, KU believes that the proposed BACT limit is consistent with the most stringent limits for comparable fuel gas heaters.[108]

6.9. STORAGE TANKS BACT ANALYSIS

No control options are available for reducing VOC emissions given the trivial amounts emitted from the proposed diesel and lube oil tanks. Therefore, a full top-down BACT analysis is not warranted. KU proposes no BACT emission limit or monitoring for the storage tanks.

[108] One or more facilities included in the RBLC have tpy GHG BACT limits. Because such limits are highly dependent on equipment capacity, tpy GHG BACT limits cannot be compared with the limit proposed by KU.

6.10. LUBE OIL DEMISTER VENTS BACT ANALYSIS

No control options are available for reducing VOC emissions given the trivial amounts emitted from the lube oil demister vents. Therefore, a full top-down BACT analysis is not warranted. KU proposes no BACT emission limit or monitoring for the lube oil demister vents.

6.11. CIRCUIT BREAKERS BACT ANALYSIS

6.11.1. GHG BACT Analysis

6.11.1.1. Background on Pollutant Formation

Leaks from the circuit breakers will result in fugitive emissions of SF_6, a GHG commonly used as a high voltage insulator and circuit-interrupting medium.

6.11.1.2. Identification of Potential Control Technologies (Step 1)

Potential control technologies identified for GHGs are included in Table 6-22.

Table 6-22. Potential GHG Control Technologies for Circuit Breakers

Pollutant	Control Technology
GHG	Alternative Dielectric Material Alternative Technology

Alternative Dielectric Material

The use of an alternative dielectric material, such as oil, compressed air, or other non-GHG as a high voltage insulator and circuit-interrupting medium in circuit breakers would eliminate the potential for leaks of GHGs.

Alternative Technology

The use of state-of-the-art circuit breaker technology with a totally enclosed pressure system to minimize leaks and the implementation of leak detection (e.g., density monitoring) to ensure that leaks of SF_6 are repaired as soon as possible would minimize the amount of GHGs emitted.

6.11.1.3. Elimination of Technically Infeasible Options (Step 2)

Although researchers have made some progress in finding SF_6 alternatives for use in low- and medium-voltage applications, the inertness and dielectric properties of SF_6 are such that no replacement gas is available for use as a substitute in existing high-voltage electric utility equipment.[109] As outlined in a 2008 annual report by the SF_6 Emission Reduction Partnership, there is no clear alternative available to SF_6.[110] The use of an alternative dielectric material is therefore technically infeasible.

[109] Christophorou, L. (1997, November). *Gases for Electrical Insulation and Arc Interruption, Possible Present and Future Alternatives to Pure SF_6, National Institute of Standards and Technology.* Retrieved from http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

[110] U.S. EPA. (2009, December). *SF_6 Emission Reduction Partnership for Electric Power Systems 2008 Annual Report.* Retrieved from http://www.epa.gov/electricpower-sf6/documents/sf6_2008_ann_report.pdf

6.11.1.4. Ranking of Remaining Control Technologies (Step 3)

The only remaining control technology is use of state-of-the-art circuit breaker technology. Ranking potential control options is therefore unnecessary.

6.11.1.5. Evaluation of Most Effective Controls (Step 4)

KU will achieve BACT through the use of state-of-the-art circuit breaker technology with a totally enclosed pressure system to minimize leaks and the implementation of density monitoring to ensure that leaks of SF_6 are repaired as soon as possible.

6.11.1.6. Selection of BACT (Step 5)

Based on the selection of circuit breakers with a totally enclosed pressure system with a design leak rate of less than 0.5 percent and the use of density monitoring, KU proposes a SF_6 BACT emission limit for the circuit breakers of 0.01 tpy SF_6 on a 12-month rolling average basis for all breakers at the plant combined.

6.12. FUGITIVE COMPONENTS BACT ANALYSIS

No control options are available for reducing GHG emissions given the trivial amounts emitted from the fugitive components. Therefore, a full top-down BACT analysis is not warranted. KU proposes that there be no BACT emission limit or monitoring required for the fugitive components.

7. AIR DISPERSION MODELING

Based on an analysis of the potential emissions increases from the proposed project, KU will be subject to PSD permitting requirements codified in 401 Kentucky Air Regulations (KAR) 51:017. The proposed project triggers PSD permitting requirements for carbon monoxide (CO), volatile organic compounds (VOCs), and greenhouse gases (GHG). PSD review is not triggered for nitrogen oxides (NO_X), particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and lead (Pb). Therefore, KU has performed an air quality modeling analysis for Class II Areas as part of this permit action for CO to meet New Source Review (NSR) PSD permitting requirements for this pollutant. The GRGS is located in an attainment area for all criteria pollutants and therefore is not subject to the Nonattainment New Source Review (NANSR) requirements. An quantitative air quality analysis relying on the output of site-specific dispersion models is not performed for VOCs because they are only regulated as photochemically reactive precursor to ozone and currently the United States Environmental Protection Agency (U.S. EPA) does not have regulatory photochemical models which can take into account the smaller spatial scales and single source impacts associated with PSD modeling evaluations. However, an ozone ambient impact analysis relying on non-modeling based analysis techniques has been prepared to demonstrate the GRGS will not cause or contribute to an exceedance of the 8-hr ozone NAAQS. An air quality analysis is not performed for GHGs because there are no ambient concentration based thresholds for which a compliance demonstration is needed and the U.S. EPA does not have a regulatory model designed to simulate GHG pollutant dispersion.

Trinity submitted an air quality modeling protocol to KDAQ on January 15, 2014.[111] Modeling analyses were conducted in a manner that conforms to the applicable rules and requirements for dispersion modeling, including the following guidance documents:

- U.S. EPA: *Guideline on Air Quality Models*, 40 CFR Part 51 - Appendix W (Revised, November 9, 2005).
- U.S. EPA: *AERMOD Implementation Guide* (Revised, March 19, 2009).
- U.S. EPA: New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, draft, October 1990.

As discussed in the previously submitted modeling protocol, air quality modeling analyses of impacts on federally protected Class I Areas are required to be performed to demonstrate compliance with PSD Class I Increment standards and air quality related values (AQRV) thresholds for regional haze and deposition. A Class I area analysis is not required for the proposed project because the pollutants for which PSD review is triggered in this project (i.e., CO and VOC) are not visibility affecting pollutants (VAP) and there are no Class I increments defined for these pollutants. In addition, there are no Class II PSD increments for CO or ozone, so a Class II PSD increment evaluation is not an applicable component of this PSD air quality analysis.

The modeling analysis presented in this section will demonstrate that emissions of these pollutants from KU after the proposed project is completed will not:

1) cause or significantly contribute to a violation of the National Ambient Air Quality Standards (NAAQS), or
2) cause any other additional adverse impacts to the surrounding area (i.e., impairment to visibility, soils and vegetation and air quality impacts from general commercial, residential, industrial and other growth associated with the source).

[111] Dispersion Modeling Protocol for PSD Permit Analysis, Kentucky Utilities Company Green River Generating Station, January 15, 2014, emailed to Ms. Rachel Chitti, KDAQ, by Mr. Tony Schroeder, Trinity Consultants.

Although not a requirement of the PSD program, KU has performed an analysis of the project toxic air pollutant (TAP) emissions pursuant to 401 KAR 63:020 as part of this application. Based on the air toxics risk assessment performed using source-wide potential emissions of hazardous air pollutants/toxic air pollutants of all non-NESHAP affected sources, no adverse impacts are expected to the health and welfare of humans, animals, and plants in the area surrounding the GRGS after the proposed project is implemented.

A CD enclosed with this application contains all relevant modeling input and output files for the PSD modeling analyses (refer to Appendix F for a list of all files included on the CD).

7.1. AIR QUALITY ASSESSMENT

This section of the application describes the modeling procedures and data resources utilized in the air quality modeling analyses.

7.1.1. Model Selection

Dispersion models predict downwind pollutant concentrations by simulating the evolution of the pollutant plume over time and space given data inputs. These data inputs include the quantity of emissions and the initial conditions of the stack exhaust to the atmosphere. According to 40 CFR Part 51, Appendix W, which contains the federal Revision to Guideline on Air Quality Models (*Guideline*), the extent to which a specific air quality model is suitable for the evaluation of source impacts depends on the (1) the meteorological and topographical complexities of the area; (2) the level of detail and accuracy needed in the analysis; (3) the technical competence of those undertaking such simulation modeling; (4) the resources available; and (5) the accuracy of the database (i.e., emissions inventory, meteorological, and air quality data).

KU used the AERMOD modeling system to represent all emissions sources at the GRGS. AERMOD is the current regulatory default model for evaluating impacts attributable to industrial facilities in the near-field (i.e., source receptor distances of less than 50 km), and is the recommended model in the *Guideline*.

The latest version (version 13350) of the AERMOD modeling system was used to estimate maximum ground-level concentrations in the Class II air pollutant analysis and air toxics risk assessment conducted for this application. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and was promulgated in December 2005 as the preferred model for use by industrial sources in this type of air quality analysis.[112] The AERMOD model has the Plume Rise Modeling Enhancements (PRIME) downwash algorithms incorporated in the regulatory version, so the direction-specific building downwash dimensions used as inputs are determined by the Building Profile Input Program, PRIME version (BPIP PRIME), version 04274.[113] BPIP PRIME is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the PRIME enhancements.[114]

The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the control module and modeling processor. AERMAP is the terrain pre-processor that is used to import terrain elevations for selected model objects and to generate

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[112] 40 CFR Part 51, Appendix W–*Guideline on Air Quality Models*, Appendix A.1– AMS/EPA Regulatory Model (AERMOD).

[113] Earth Tech, Inc., *Addendum to the ISC3 User's Guide, The PRIME Plume Rise and Building Downwash Model*, Concord, MA.

[114] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised)*, Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

the receptor hill height scale data that are used by AERMOD to drive advanced terrain processing algorithms. National elevation dataset (NED) data available from the USGS were utilized to interpolate surveyed elevations onto user-specified receptor grids, buildings, and sources in the absence of more accurate site-specific (i.e., site surveys, GPS analyses, etc.) elevation data.

AERMET generates a separate surface file and vertical profile file to pass meteorological observations and turbulence parameters to AERMOD. AERMET meteorological data are refined for a particular analysis based on the choice of micrometeorological parameters that are linked to the land use and land cover (LULC) around the particular meteorological site. By feeding raw surface and upper air station National Weather Service (NWS) observation data to AERMET, a complete set of model-ready meteorological data is created. A general discussion of the AERMET processing used in this analysis is provided in Section 7.1.2 below.

BREEZE® software, developed by Trinity Consultants, was used to assist in developing the model input files for AERMOD. This software program incorporates the most recent versions of AERMOD (version 13350) and AERMAP (version 11103) to estimate ambient impacts from the modeled sources. Following procedures outlined in the *Guideline*, the AERMOD modeling was performed using all regulatory default options.

7.1.2. Meteorological Data

Site-specific dispersion models require a sequential hourly record of dispersion meteorology representative of the region within which the source is located. In the absence of site-specific measurements, the *Guideline* requires five years of reliable, quality assured, and representative meteorological data to be used in regulatory modeling analyses. The representativeness of a particular observation site should be evaluated with respect to four factors: (1) the proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected.

Regulatory air quality modeling using AERMOD requires five years of quality-assured NWS meteorological data or at least one year of site-specific meteorological data. Surface observation stations form a relatively dense network, are almost always found at airports, and are typically operated by the NWS. There are fewer upper air stations than surface observation points since the upper atmosphere is less vulnerable to local effects caused by terrain or other land influences and is therefore less variable. The NWS operates virtually all available upper air measurement stations in the United States.

As shown in Table 7-1 below, two (2) National Weather Service surface observation stations within 100 km of the GRGS and two (2) upper air stations within 400 km of the site were evaluated as candidates for "representative" data sources for the GRGS. From among the candidate NWS surface meteorological stations within 100 km of the GRGS, the Bowling Green Warren County Airport (BWG) was selected for this modeling analysis primarily based on proximity (76.3 km south-southeast) and similarity of the terrain surrounding the airport in comparison to the GRGS. The closest upper air station to the GRGS with upper air temperatures and wind speeds that are expected to be most representative of the GRGS is the Nashville, TN International Airport site (BNA). The most recent, readily available five years of meteorological data from the Bowling Green surface station (i.e., 2009 to 2013) were used in the air quality modeling analysis.

Table 7-1. Summary of Candidate Meteorological Stations for Modeling Analysis

Station Name	WBAN Station ID No	Station Call Sign	Station Location	Distance to GRGS (km)	Observation Type
Bowling Green Warren Co. Airport	93808	KBWG	Bowling Green, KY	76.3	Surface
Evansville Regional Airport	93817	KEVV	Evansville, IN	83.2	Surface
Nashville International Airport	13897	KBNA	Nashville, TN	133.1	Upper Air
Wilmington Airborne Park	13841	KILN	Wilmington, OH	367.8	Upper Air

7.1.2.1. AERMET Meteorological Data Processing

AERMET, the meteorological preprocessing program from AERMOD, is a 3-stage system. The first stage reads in and performs quality assurance/quality control (QA/QC) on the raw NWS surface and upper air data files. The second stage synchronizes the observation times and merges the surface and upper air files together. The last stage incorporates user-specified micrometeorological parameters (albedo, Bowen Ratio, surface roughness) with the observational data to compute the necessary variables for AERMOD (e.g., friction velocity, Monin-Obukhov Length, etc.). Meteorological input files for this modeling analysis were developed by Trinity using AERMET (version 13350) following the procedures described below.

Surface and upper air data QA/QC and processing were completed in Stage 1 and Trinity confirmed that the surface and upper air datasets are at least 90 percent complete, by parameter and calendar quarter, in accordance with EPA guidance. No filling of raw data was necessary as all quarters contained more than 90 percent complete data, the minimum completeness criteria established by EPA. The AERMINUTE program (version 11325) was used to process 1-minute wind speed and direction data from BWG into 1-hour average values. The hourly average wind data processed using AERMINUTE were used in Stage 2 of AERMET to reduce the number of calm or missing wind observations present in the hourly meteorological dataset. Stage 2 of AERMET was run to combine the hourly surface data, AERMINUTE processed surface wind data, and twice daily upper air data into a single file. Since the surface and upper air data are based on GMT, but AERMOD requires meteorological data in local standard time (LST), the observation times must be synchronized as well. Once the merge file was created, the data were combined with land use-specific surface characteristics (albedo, Bowen ratio, and surface roughness) to create the AERMOD-ready dataset. AERMET accepts surface characteristics as annual, seasonal or monthly averages, over the number of user-specified horizontal sectors based on wind direction, ranging from 1 to 12.

The Stage 3 processor combines the observational data with the surface characteristics to calculate the micrometeorological input parameters required by the AERMOD model. These parameters are output in the .sfc and .pfl files that compose an AERMOD-ready dataset. Trinity calculated surface characteristics using the AERSURFACE program for the surface data observation site and used these characteristics to create AERMOD ready surface and upper air files for use throughout the dispersion modeling analysis. AERSURFACE (version 13016) files for BWG were generated for wet, dry, and average moisture conditions using NLCD92 data. These files used a location of 551,315 m E and 4,091,065 m N in UTM Zone 16 (NAD83) as the BWG surface station location, and a surface roughness radius of 1 km and twelve (12) even 30-degree sectors. Seasonal land use parameters were output. In accordance with a September 17, 2009 U.S. EPA Modeling Clearinghouse memo issued for another recent project using BWG surface data, Gust Factor Method derived surface roughness data were substituted for upwind sectors between 270 and 30 degrees.[115] The seasonal moisture parameters were chosen by comparing the seasonal precipitation from Bowling Green to the upper and lower 30th percentiles based on 1984-2013 data from Nashville.[116] Nashville data were used to define climate normal precipitation because no source of information for monthly precipitation for the entire period 1984-2013 was available for the Bowling Green surface station and the Nashville station was the closely first order NWS station to the Bowling Green station with precipitation available for the entire 30 year climate period.

A minimum threshold wind speed of 0.5 m/s is implemented using the THRESH_1MIN keyword incorporated into AERMET, as suggested in Section 2.3.2 of the latest addendum to the *AERMET User's Guide*.[117] All hours with wind speeds below this value will be treated as "calm" in AERMOD. During the five year data period, the anemometer height for the BWG surface station was 7.92 meters.

7.1.2.2. Surface Characteristic Comparison

In the *AERMOD Implementation Guide*, EPA suggests the completion of a meteorological data representativeness evaluation.[118] The typical analysis recommended by the *AERMOD Implementation Guide* includes a comparison of the surface characteristics (based on land use) at the meteorological observation site and the plant site to prove that the characteristics at the observation site are representative of the plant site. The following discussion highlights the method by which the surface characteristics for the BWG surface observation site and GRGS were calculated to complete this comparison.

To define the land use characteristics and micrometeorological parameters in the areas of interest, Trinity applied the latest version (version 13016) of the AERSURFACE utility to perform a digital mapping of land use and cover in accordance with the procedures identified in the *AERMOD Implementation Guideline* and the *AERSURFACE User's Guide*.[119] Using publicly available digital land cover datasets and lookup tables of surface characteristics that vary by season and land cover type, the AERSURFACE tool can generate realistic and reproducible surface characteristics for any site of interest that can then be directly imported into AERMET for generating AERMOD-ready meteorological datasets. As recommended by the *AERSURFACE User's Guide*, the land use analysis was prepared using digital land use and cover (LULC) data developed by the Multi-Resolution Land Characteristics Consortium (MRLC). One of the objectives of the MRLC, a partnership of the EPA, NASA, NOAA, USGS, and U.S. Forest Service, among other federal agencies, was the production of land cover data derived from images acquired by Landsat's Thematic Mapper (TM) sensor. The 1992 National Land Cover Dataset (NLCD92), the only dataset currently accepted by AERSURFACE, is provided for public download as geo-referenced images on the MRLC website.[120] The USGS NLCD92 data utilized by AERSURFACE provides land cover with a spatial resolution of 30 meters based on the 21-category classification scheme. AERSURFACE uses a set of seasonal surface characteristics for each of the 21 categories that were derived from literature as documented in Appendix A of the *AERSURFACE User's Guide*. NLCD92 files for the two areas of interest (GRGS and BWG) were obtained from the USGS Seamless Data Server.[121]

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[115] U.S. EPA, Air Quality Modeling Group, "Use of Non-default Radius for Determining Surface Roughness for AERMET," September 17, 2009 (http://cfpub.epa.gov/oarweb/MCHISRS/index.cfm?fuseaction=main.resultdetails&recnum=09-IV%20-01).

[116] The Nashville data were used because no source of information on monthly precipitation for the entire period 1984-2013 was available for the Bowling Green surface station.

[117] U.S. EPA, Addendum – User's Guide for the AERMOD Meteorological Preprocessor (AERMET), December 2013.

[118] EPA, Office of Air Quality Planning and Standards. AERMOD Implementation Guide, Last Revised: March 19, 2009, http://www.epa.gov/ttn/scram/7thconf/aermod/aermod_implmtn_guide_19March2009.pdf

[119] EPA, Office of Air Quality Planning and Standards. AERSURFACE User's Guide. EPA 454/B-08-001. Research Triangle Park, North Carolina. January 2013.

[120] http://www.mrlc.gov/index.asp

[121] http://seamless.usgs.gov/

As Bowen ratio and albedo do not vary significantly over the area immediately surrounding a meteorological observation or plant site, AERSURFACE uses a simple unweighted geometric mean for a default domain defined by a 10 km by 10 km area centered on the site of interest. However, based on the method for constructing realistic planetary boundary layer (PBL) similarity profiles in AERMOD and the heterogeneity of land use typical to areas surrounding an observation site at an airport or an industrial facility, accurately characterizing the surface roughness length, the key parameter in characterizing the mechanical turbulence in the approach wind flow, is the most important consideration in the AERSURFACE analysis. As such, AERSURFACE determines the surface roughness length based on an inverse distance weighted geometric mean (which can be varied by sector to account for consistent variations in the land cover near the site of interest provided the sector widths are no smaller than 30 degrees) for a default upwind distance of 1 km. Consistent with EPA's default recommendations for conducting a regulatory AERSURFACE analysis, KU ran AERSURFACE with 12 equal 30 degree sectors starting at 0 degrees (i.e., due north) and extending to 1 km for the surface roughness study area and with a seasonal temporal resolution using the default seasonal assignments for each month.

To address any significant growth that has occurred in the areas under consideration, more recent NLCD 2001 land cover data made available on the MRLC website were compared to the NLCD92 data. As discussed in the previously referenced September 2009 U.S. EPA Modeling Clearinghouse memo, significant land cover changes have occurred in the area directly north of the BWG anemometer (in the sector from about 270 degrees to 30 degrees or Sectors 1 and 10-12 from the AERSURFACE output) due to the completion of a residential development near the golf course adjacent to the airport. This development appears to have been completed prior to 2009, the earliest meteorological data year considered in the modeling analysis, and therefore, the effect of this land use change should be evaluated when developing surface roughness for sectors covering the golf course community. In order to quantify the influence of this land use change on surface roughness, KU has relied on the gust factor method (GFM) analysis performed by OAQPS to estimate surface roughness for Sectors 1 and 10-12 and has replaced the seasonal AERSURFACE output for these sectors with the BWG GFM results presented in Figure 1 of the SCRAM memo. According to the SCRAM memo, the GFM "is based on the concept that the gustiness of the horizontal wind is a measure of the level of turbulence within the boundary layer flow and can be correlated with the effective surface roughness length."[122] Surface roughness estimates from applying GFM to winds measured at the BWG station show good correlation with the AERSURFACE output for sectors in the study area not experiencing land use changes since 1992 indicating this is a valid technique for deriving surface roughness at this site and can be used to address the identified land use changes in Sectors 1 and 10-12. Therefore, the GFM adjusted surface roughness lengths are used in the comparison of the surface characteristics between BWG and the GRGS.

KU also conducted a detailed review of the NLCD92 data for the area surrounding the GRGGS. Based on a comparison of aerial photography, NCLD data for 2001 and 2006, as well as an updated site plan reflecting post-project conditions, KU determined that the land cover at the GRGS, both before and after the proposed project is completed, was not accurately reflected in the 1992 LULC data. As such, Trinity utilized ArcMap Version 9.3.1 and the ArcGIS Spatial Analyst Extension to modify the NLCD92 file to reflect changes in land cover at the GRGS. Updates to the land cover for the existing plant configuration, involved changing areas incorrectly reflected as Emergent Herbaceous Wetlands (92), Deciduous Forest (41), Open Water (11) and Row Crops (82) to Commercial/Industrial/Transportation (23). Image files showing the original NLCD92 data and the modified land cover data for the area surrounding the GRGS are included in Appendix F. This modified NLCD file for the GRGS was fed to AERSURFACE to generate the surface characteristics surrounding the facility for comparison to the surface characteristics in the area surrounding BWG.

[122] U.S. EPA, Air Quality Modeling Group, "Use of Non-default Radius for Determining Surface Roughness for AERMET," September 17, 2009 (http://cfpub.epa.gov/oarweb/MCHISRS/index.cfm?fuseaction=main.resultdetails&recnum=09-IV%20-01).

If two locations have similar land use and cover, then the locations are expected to have similar surface characteristics. Thus, as part of demonstrating the representativeness of a NWS station, a land use analysis is recommended in the March 19, 2009 version of the *AERMOD Implementation Guide* where by the surface characteristics predicted based on the land use in the area immediately surrounding the proposed source (the facility) are compared to the surface characteristics for the area immediately surrounding the NWS site. Tables comparing the ratios of the surface characteristics for the GRGS to the surface characteristics of the BWG meteorological observation site on a sector-by-sector, season-by-season, and study area-wide seasonal-average basis are provided in Appendix G. The results of this analysis demonstrate reasonable agreement between the surface characteristics at the GRGS and BWG, especially considering the surface roughness for most industrial sites can be a factor of 10 (or more) higher than the surface roughness common to airport sites.

7.1.3. Coordinate System

The location of emission sources, structures, and receptors for all modeling analyses were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 kilometers [km]). The datum is based on North American Datum 1983 (NAD 83). UTM coordinates for this analysis all reside within UTM Zone 16.

7.1.4. Treatment of Terrain

A designation of terrain at a particular receptor is source-dependent, since it depends on an individual source's effective plume height. AERMOD is capable of estimating impacts in both simple and complex terrain. A single base elevation of 134.11 meters was used in the model data files for most sources and buildings associated with the NGCC plant, because the power block and switchyard areas at the facility will be graded.[123]

Receptor elevations required by AERMOD were determined using the AERMAP terrain preprocessor (version 11103). AERMAP also calculates receptor hill height parameters required by AERMOD. As suggested in the *AERMOD Implementation Guide*, terrain elevations from the USGS 1-arcsecond NED data were used for the AERMAP processing of receptors and regional inventory sources.[124] NED data files were downloaded from USGS's Multi-Resolution Land Characteristics Consortium (MRLC) Viewer.[125]

7.1.5. Receptor Grid

Ground-level concentrations were calculated in the Significance Analyses within four nested Cartesian receptor grids to determine the location of the maximum estimated impact at a resolution of 100-meter grid spacing. The four Cartesian grids covered a region extending from all edges of KU's property boundary to the point where the impacts from the project are no longer significant.

As compliance with NAAQS is only required in areas regulated as "ambient air," in developing the receptor grid for the modeling analysis, KU excluded all company owned property to which public access is restricted because it is fenced and/or monitored and will not be considered "ambient air."

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[123] A base elevation of 132.59 meters was used for the area surrounding the cooling towers and a base elevation of 135.64 meters was used for the water treatment area because these areas of the facility have a slightly different grade compared with the power block and switchyard area. A base elevation of 126.49 meters was used for buildings associated with the existing coal-fired boilers. These buildings were retained in the model file because these buildings may remain at the facility even after operation of emission units within them ceases.

[124] Section 4.3 of the March 19, 2009 version of U.S. EPA's *AERMOD Implementation Guide* recommends that AERMOD users transition from the use of DEM data to NED data in AERMAP as soon as practicable.

[125] http://www.mrlc.gov/viewerjs/

An explanation of the receptor grids that will be used in the modeling analyses is provided below.

1. **Fence Line Grid:** "Fence line" grid consisting of evenly-spaced receptors 100 meters apart placed along the main property boundary of the GRGS.

2. **Fine Cartesian Grid:** A "fine" grid containing 100-meter spaced receptors extending approximately 2 km from the center of the property but beyond the fence line,

3. **Medium Cartesian Grid:** A "medium" grid containing 500-meter spaced receptors extending from 2 km to 5 km from the center of the facility, exclusive of receptors on the fine grid,

4. **Coarse Cartesian Grid:** A "coarse grid" containing 1,000-meter spaced receptors extending from 5 km to 20 km from the center of the facility, exclusive of receptors on the fine and medium grids, and

Figure 7-1 shows the location of the GRGS fenceline overlaid on an aerial photograph of the facility.

7.1.6. Building Downwash

The *Guideline* requires the evaluation of the potential for physical structures to affect the dispersion of emissions from stack sources. The exhaust from stacks that are located within specified distances of buildings may be subject to "aerodynamic building downwash" under certain meteorological conditions. This determination is made by comparing actual stack height to the Good Engineering Practice (GEP) stack height. The modeled emission units at the facility were evaluated in terms of their proximity to nearby structures.

A GEP analysis of all modeled point sources at the GRGS in relation to each building was performed to evaluate which building has the greatest influence on the dispersion of the each stack's emissions. The GEP height for each stack calculated using the dominant structure's height and maximum projected width was also determined. The GEP height is the greater of the U.S. EPA formula height or 65 m. The actual release heights of all stacks are less than 65 m, and therefore, all stacks were represented in the modeling at their actual release heights and are subject to downwash effects.

Direction-specific equivalent building dimensions used as input to the AERMOD model to simulate the impacts of downwash are calculated using the U.S. EPA-sanctioned Building Profile Input Program (BPIP-PRIME) version 04274. BPIP-PRIME is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents and has been adapted to incorporate the PRIME downwash algorithms.[126] Building downwash input and output files are provided on the modeling file CD in Appendix F.

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[126] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) (Revised), Research Triangle Park, North Carolina, EPA 450/4-80-023R, June 1985.

Figure 7-1. KU GRGS Fence Line Receptor Grid Used in Modeling Analyses

Coordinates are in UTM NAD83 Zone 16.

7.2. MODELING REQUIREMENTS

The following modeling methodologies and data resources were used to evaluate whether modeled ambient concentrations would cause or contribute to exceedances of the NAAQS for CO.

The air dispersion modeling analyses were conducted in accordance with 40 CFR Part 51, Appendix W, which contains the *Guideline* and is consistent with current and recommended U.S. EPA procedures for dispersion modeling analyses.[127] The Class II area modeling analysis is completed in three principle steps: the Significance Analysis, the NAAQS Analysis, and the PSD Increment Analysis, which are described below.

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[127] U.S. EPA, Office of Air Quality Planning and Standards, *Federal Register* Vol. 70 / No. 216, pp. 68218-68261, 40 CFR 51, Appendix W, *Revision to Guideline on Air Quality Models*, November 9, 2005.

7.2.1. Significance Analysis

The Significance Analysis is conducted to determine whether the emissions change associated with project would cause a significant impact upon the area surrounding the facility. "Significant" impacts are defined by ambient concentration thresholds commonly referred to as the Significant Impact Levels (SILs). Table 7-2 lists the SIL and NAAQS for CO. As stated previously, EPA has not promulgated PSD Increment for CO.

The Significance Analysis only addressed impacts from CO emissions for the proposed project, as it is the only criteria pollutant for which PSD review was triggered. If the highest modeled ambient concentrations for a pollutant for all averaging periods are less than the applicable SILs when the emissions increases from the updated emission rates are modeled, then further analyses (NAAQS and PSD Increment) are not required for that pollutant, as is the case in this analysis.

7.2.2. Pre-Construction Ambient Monitoring Requirements

In addition to determining whether the applicant can forego further analysis, the Significance Analysis is used to determine whether ambient monitoring requirements apply. Pursuant to 401 KAR 51:017 Section 7(5), a source may be exempted from pre-construction monitoring if either: 1) the ambient impacts predicted in the Significance Analysis portion of the Class II Area modeling analysis are below the SMC or 2) the existing ambient air quality in the area surrounding the proposed site is less than the SMC.

To determine whether pre-construction ambient monitoring should be considered for the proposed project, the maximum impacts attributable to the proposed project were assessed against the SMCs. The SMC for the applicable averaging period for CO is provided in 401 KAR 51:017 Section 7 (5)(a) and are listed in Table 7-2. Maximum modeled impacts of CO are less than the SMC. Therefore, KU requests that KDAQ waive the pre-construction monitoring requirements of 401 KAR 51:017 Section 11 for the project.

Table 7-2. SILs, NAAQS, and SMC for CO

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	Primary and Secondary NAAQS ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)
CO	1-hour	2,000	40,000 (35 ppm)[a]	--	--
	8-hour	500	10,000 (9 ppm)[a]	--	575

a Not to be exceeded more than once per year.

7.3. MODELED ON-SITE EMISSION SOURCES

7.3.1. Load Analysis

The *Guideline on Air Quality Models* states that modeling should contain sufficient detail to determine the maximum ambient concentration of the pollutant under consideration, and that this will likely involve modeling several operating loads or production rates. For some types of sources, operating at a reduced load translates into reduced stack gas exit velocities leading to different and potentially higher impact characteristics. The combustion turbines are the only emissions sources at the GRGS that will operate at variable loads during normal operation of the plant. KU conducted a load analysis to consider four (4) operating scenarios for each CCCT:

- 100% load;
- 75% load;
- 50% load ; and
- Startup/Shutdown

For all combinations of turbine operating scenarios across the two (2) combustion turbines that could realistically occur, KU developed a plant-wide source group. A table showing all source groups evaluated in the Significance Analysis is provided in Appendix H. The maximum 1-hour and 8-hour average pound per hour emission rates for each normal steady-state load case [i.e., 100 % load, 75% load, and 50%] were chosen out of all turbine options for use in the dispersion modeling analysis. Selection of the startup/shutdown modeled emission rates across the available turbine options is discussed in the following subsection.

7.3.2. Treatment of Startup/Shutdown Emissions

When starting up the combustion turbines, there is a brief period when the pollution control equipment will not be functioning (e.g., oxidation catalyst will only operate at maximum efficiency once specific temperature has been reached), and thus emissions of CO during startup can be higher than during normal operation. Based on the current dispatch model for the new configuration of the GRGS, the facility would serve as either a base load or intermediate load plant with periodic startups/shutdowns (refer to Table 2-2). Startup shall be defined for each combustion turbine/HRSG unit as the period of time between the first firing of the combustion turbine to permitted emissions compliance for the respective combustion turbine/HRSG units. The actual number of startups/shutdowns could be considerably less than currently expected if the demand for power in the region served by the plant increases over time and/or the base load generating capacity in the region is reduced over time through the shutdown of older, existing plants. Regardless, KU has modeled the worst-case emissions from each of the anticipated startup/shutdown cases (i.e., cold start, warm start, hot start, and shutdown) to ensure the CO Significance Analysis reflects the highest short-term offsite impacts that could be attributable to the turbine operations.

As shown in Table 7-1, the CO SILs and SMC are based on 1-hour and 8-hour average concentrations. For certain turbine options currently under consideration by KU, certain startup and/or shutdown events are expected to be less than 1 hour in duration and for all turbine options, these events are expected to be less than 8 hours in duration. For events shorter than the averaging period of the standard, worst-case 1-hour and 8-hour average CO emission rates were calculated for each turbine option assuming that one startup or shutdown event could occur in the 1-hour or 8-hour period and that the remainder of the period would consist of the combustion turbines operating at 100% load. An average pound per hour emission rate was then calculated for each startup or shutdown condition and each turbine option by dividing the total emissions by one for the 1-hour average emission rate and by eight for the 8-hour average emission rate. The maximum 1-hour and 8-hour average pound per hour emission rates where then chosen out of all turbine options and startup or shutdown conditions for use in the dispersion modeling analysis.

7.3.3. Modeled Source Inventory

A list of new emission sources of CO at GRGS to be included in the dispersion modeling analysis is included in Appendix H along with the corresponding source designation used in the modeling files. Appendix H also provides a complete inventory of emission rates and source parameters for on-site emission sources modeled in the analyses. All sources of CO included in this analysis are point sources with unobstructed vertical releases. For point sources, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses. As a conservative measure, the minimum exhaust flow rate and temperature from of all turbine options considered for a particular load scenario were input to the model along with the maximum pound per hour emission rate from among all of the turbine options for the corresponding load scenario. Given the larger disparity in 1-hour and 8-hour average startup/shutdown emission rates across the turbine options being considered, stack parameters were paired with directly with modeled emission rates rather than using the overly conservative assumption that the minimum stack flow rate and temperature out of all turbine options would occur simultaneously with the highest modeled emission rate out of all turbine options. Appendix H provides the stack parameters for all emission sources of CO included in this analysis.

7.4. SUMMARY OF DISPERSION MODELING RESULTS

This section summarizes the results of the dispersion modeling analyses and demonstrates that the proposed project does not cause or contribute to an exceedance of the NAAQS. As discussed in Section 7.2.1, if the CO Significance Analysis shows results below applicable SILs, a cumulative NAAQS analysis is not required. The significance modeling included all new emission sources emitting CO at the GRGS and relied on the modeling parameters provided in Appendix H.

The results of the CO significance analyses are provided in Table 7-2. These results show that the proposed project results in modeled impacts below the CO SIL for the 1-hr and 8-hr averaging periods.

Table 7-3. CO Significance Analysis

Averaging Period	Year for Met. Data	SIL ($\mu g/m^3$)	SMC ($\mu g/m^3$)	Maximum 1st High Impact ($\mu g/m^3$)	UTM East[a] (m)	UTM North[a] (m)
1-hour	2009			1,370.94	488,903.50	4,136,040.60
	2010			1,494.62	488,903.50	4,136,040.60
	2011			1,450.14	488,705.10	4,136,397.90
	2012			1,418.04	488,903.50	4,136,040.60
	2013			1,360.14	488,903.50	4,136,040.60
	Max. of 5 Years	**2,000**	**N/A**	**1,494.62**	488,903.50	4,136,040.60
8-hour	2009			99.55	488,903.50	4,136,040.60
	2010			80.61	488,505.10	4,135,697.90
	2011			94.00	488,830.90	4,135,971.80
	2012			95.61	488,976.10	4,136,109.40
	2013			102.57	488,903.50	4,136,040.60
	Max. of 5 Years	**500**	**575**	**102.57**	488,903.50	4,136,040.60

[a] UTM coordinates are in NAD83.

7.5. SIGNIFICANT MONITORING CONCENTRATION ANALYSIS

Results of the Significance Analysis presented in Table 7-3 indicate CO impacts are less than the SMC; therefore, no pre-construction monitoring is required for these pollutants. As discussed in Section 7.2.2, KU requests that KDAQ waive the preconstruction monitoring requirements since concentrations of CO due to this project are below the SMC.

7.6. OZONE AMBIENT IMPACT ANALYSIS

Unlike other criteria pollutants, ozone is predominantly a secondary pollutant, meaning that it is formed through chemical reactions in the atmosphere. Ozone formation mechanisms are very complex, are affected by a number of variables, and are highly dependent on numerous atmospheric and geographical influences (i.e., meteorology, topography, land use, etc.). The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and biogenic sources (e.g., vegetation, wild fires, etc.). Ozone formation is a complicated nonlinear process that typically requires favorable meteorological conditions in addition to VOC and NO_X emissions. Ozone formation may be limited by either the availability of NO_X or VOC depending on the localized emissions profile of the airshed under consideration. Meteorological conditions favorable for high levels of ozone formation include warm temperatures, clear skies causing high solar radiation, and stable boundary layer conditions typically associated with low wind speeds and diurnal temperature profile changes. As a regional-scale pollutant, ozone formation can be influenced by transport from other areas.

While the GRGS will not directly emit ozone, the proposed project will cause an emissions increase of VOC that is greater than 100 tpy, thus triggering the ozone ambient impact analysis requirements in 40 CFR 51.166(i)(5)(i)(e) n. 1 and 401 KAR 51:017 Section 7(5)(a). Under a narrow range of meteorological conditions, ozone precursors generated locally or transported from regional sources can contribute to elevated concentrations of ground level ozone. Because of the photochemistry involved and the influence of transport on ozone formation, ozone impacts are assessed on a regional scale considering emissions from the entire inventory of sources (not a single source). The regional-scale models available to complete ozone assessments are both complex and resource intensive. Although the science and technology associated with photochemical models used for ozone has advanced significantly in the last few years, U.S. EPA has acknowledged in response to a recent petition for rulemaking that these modeling tools are not appropriate for recommendation as the preferred model in a single-source context. Such single-source ozone models are still being developed and evaluated, and U.S. EPA has yet to approve an ozone model for single source applications.[128] In the absence of an approved model, U.S. EPA has not even provided specific guidance for completing an ambient impact analysis for ozone under PSD.

The only available guidance for evaluating single source ozone impacts in the near field is provided in Subsection 5.2.1(c) of the *Guideline*, which states:

> *Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the Regional Office to determine the most suitable approach on a case-by-case basis (subsection 3.2.2).*

Consistent with several recent ozone ambient impact analyses prepared for PSD projects in Kentucky and a U.S. EPA Investigative Report into alleged violations of Title VI of the Civil Rights Act of 1964, KU is providing the following qualitative ozone impacts analysis for the proposed project.[129] This case-specific approach focuses on the emissions of ozone precursors from the GRGS and provides a qualitative measure of their potential ozone contribution to the area surrounding the plant. The first step in the analysis is to gather ozone ambient monitoring data to understand the nature of ozone formation issues in the study area. Area-wide NO_X and VOC emissions data for the areas surrounding the candidate monitoring stations and the GRGS are also compiled for use in interpreting the spatial trends in monitored ozone concentrations. Finally, ozone precursor emissions

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[128] Letter from Ms. Gina McCarthy, Assistant Administrator, U.S. EPA, Office of Air and Radiation to Mr. Robert Ukeiley representing The Sierra Club, dated January 4, 2012 (available at http://www.epa.gov/scram001/10thmodconf/review_material/Sierra_Club_Petition_OAR-11-002-1093.pdf)
[129] U.S. EPA Office of Civil Rights, Investigative Report for Title VI Administrative Complaint, File No. 01R-95-R9, August 30, 2012 (available at http://www.epa.gov/ocr/TitleVIcases/decisions/)

changes attributable to the project are viewed in the context of the overall emissions of NO_X and VOC in the surrounding airshed to determine whether the emissions from the proposed project could have a discernible impact on ozone levels.

7.6.1. Representative Monitor Selection

Selecting an existing ozone monitoring site that best represents the air quality in the region surrounding the GRGS is the first step in assessing the project's potential impacts on ozone formation. A monitoring station is selected from among the candidate monitors in the area based on an evaluation of the following criteria:

1. Proximity of the ambient monitoring station to the GRGS;
2. Availability of complete ozone monitoring data that has undergone Quality Assurance and Quality Control (QAQC) for the most recent three calendar years (i.e., 2011 to 2013); and
3. Similarity of the emissions profile and surrounding airshed in the region of the monitoring station and the GRGS.

7.6.1.1. Proximity and Data Completeness Criteria

As shown in Figure 7-2, there are five (5) candidate ozone monitoring stations that collected three years of quality assured data in the period from 2011 to 2013 and that are located within relative proximity to the GRGS. The locations of these stations relative to the GRGS and their 8-hour ozone NAAQS design values in the most recent three-year period are indexed Table 7-4. The metropolitan statistical area (MSA)/core-based statistical area (CBSA), monitor type, monitoring objective, and measurement scale descriptions for each candidate monitor is provided in Table 7-5. These candidate monitoring sites are evaluated further using the remaining criteria to determine their representativeness for establishing the ozone background concentration for the proposed project.

Table 7-4. Candidate Ambient Ozone Monitoring Sites Based on Proximity and Data Availability

Site ID	Plot ID	Local Site Name	City	County	State	Downwind Direction to Monitor	Distance to Green River Station (km)	8-hr Average Ozone Concentration[1] (ppm)
21-059-0005	1	Owensboro Primary	NA	Daviess	Kentucky	N	46.4	0.077
21-047-0006	2	Hopkinsville	NA	Christian	Kentucky	SSW	53.3	0.069
21-101-0014	3	Baskett	NA	Henderson	Kentucky	NW	63.8	0.076
21-091-0012	4	Lewisport	Lewisport	Hancock	Kentucky	NNE	66.7	0.073
18-173-0011	5	Dayville	NA	Warrick	Indiana	NNW	67.8	0.073

[1] Three-year average (2011-2013) of 4th highest 8-hr average measured ozone concentrations.

Table 7-5. Monitoring Descriptions for Candidate Ambient Ozone Monitoring Sites

Site ID	County	State	MSA or CBSA	Monitor Type	Monitor Objective	Measurement Scale	Measurement Scale Definition
21-059-0005	Daviess	Kentucky	Owensboro, KY	SLAMS	Population Exposure	Neighborhood	500 m to 4 km
21-047-0006	Christian	Kentucky	Clarksville, TN-KY	SLAMS	Multiple	Regional Scale	50 km to 100's km
21-101-0014	Henderson	Kentucky	Evansille, IN-KY	Special Purpose	Max Ozone Concentration	Urban Scale	4 km to 50 km
21-091-0012	Hancock	Kentucky	Owensboro, KY	SLAMS	Max Ozone Concentration	Urban Scale	4 km to 50 km
18-173-0011	Warrick	Indiana	Evansille, IN-KY	SLAMS	Multiple	Urban Scale	4 km to 50 km

The ozone NAAQS design values from the monitoring stations in proximity to the GRGS are relatively uniform, which reflects the regional nature of ozone formation and transport. However, the 2011 to 2013 8-hr ozone NAAQS design concentrations for two (2) of the five (5) closest ozone monitors to the GRGS exceed the NAAQS due to localized influences which warrant additional consideration in evaluating the final criteria of the monitor section process (i.e., similarities/dissimilarities of ozone precursor emissions profiles).

7.6.2. Ozone Precursor Emissions Profile Criterion

For an ambient ozone monitoring station to be considered representative of the GRGS located in Muhlenberg County, Kentucky, the station should be located in an airshed that shares a similar emissions profile to the GRGS airshed and is characterized by a similar fraction of rural and urban development. A 50 km screening distance is selected to define the extent of the airshed rather than just the county or MSA within which the monitoring station/plant site is located because ozone formation is a regional phenomenon and this is the maximum distance over which near-field Class II Area air quality analyses are typically conducted.

7.6.2.1. GRGS Airshed Characteristics

The GRGS is located in Muhlenberg County which covers a total area of 467 square miles, has a population of 31,181, and a corresponding population density of 67 persons per square mile (ranking Muhlenberg County as the 33rd most populous county from among Kentucky's 120 total counties).[130] Muhlenberg County is classified under the 2013 Rural-Urban Continuum Codes published by the U.S. Department of Agriculture Economic Research Service as a "nonmetro - urban population of 2,500 to 19,999, adjacent to a metro area" (where the adjacent metro area is the Owensboro MSA).[131] As shown in Figure 7-3, Muhlenberg County is considered a micropolitan statistical area primarily due to residential development in and around Greenville, Powderly, and Central City, in the central portion of the county. Visual inspection of the 2006 National Land Cover Dataset, high resolution aerial photography, and topographic maps for Muhlenberg County and the surrounding airshed reveals that the area is dominated by deciduous forest with some agricultural land scattered throughout along rivers and streams.[132] The GRGS airshed includes the Madisonville and Central City micropolitan statistical areas, most of the Owensboro MSA, and a very small portion of the Evansville MSA. The portion of the Evansville MSA included in the GRGS airshed only includes the extreme southeast portion of Henderson County which is sparsely populated and does not contain any major transportation corridors.

[130] U.S. Census Bureau, State & County QuickFacts: Muhlenberg County, Kentucky, available at: http://quickfacts.census.gov/qfd/states/21/21177.html
[131] U.S. Department of Agriculture Economic Research Service, 2013 Rural-Urban Continuum Codes for Kentucky, available at http://www.ers.usda.gov/data-products/rural-urban-continuum-codes.aspx.
[132] Refer to red circle in Figure 7-2 for 50 km region defining the airshed for the GRGS. Counties in this 50 km region include Butler, Christian, Daviess, Grayson, Henderson, Hopkins, Logan, McClean, Muhleberg, Ohio, Todd, and Webster Counties in Kentucky and Spencer County in Indiana.

As shown in Figure 7-4, the population within the GRGS airshed according to the U.S. Census Bureau is 443,788.[133] The area-wide NO_X emissions for the GRGS airshed reported in EPA's 2011 National Emissions Inventory (NEI) are 67,770 ton per year, with more than 65 percent of the total NO_X emissions generated from Fuel Combustion. Of the 45,511 tpy NO_X emissions contribution from the Fuel Combustion sector, nearly 100 percent of the emissions are attributable to the coal-fired Electric Generating Units (EGU) depicted in Figure 7-2 and further itemized in Table 7-6. The area-wide VOC emissions for the GRGS airshed from the 2011 NEI are 103,791 tpy, with emissions from biogenic sources and fires representing more than 75 percent of the VOC emissions total (refer to Figure 7-5). Anthropogenic VOC emissions in the GRGS airshed are predominantly generated by mobile sources, industrial processes, and solvent usage, but these sources only comprise a relatively small fraction of the total VOC emissions that could potentially affect ozone formation in the area.

7.6.2.2. Monitoring Station Location Characteristics

As shown in Figures 7-2 and 7-3 and Table 7-5, all of the candidate ozone monitoring stations are located in large areas of urban development referred to as MSAs. MSAs are developed areas that have at least one urbanized area of 50,000 or more population, plus adjacent territory that has a high degree of social and economic integration with the core as measured by commuting ties (i.e., suburban development surrounding the city center). Another metric for measuring urban development in smaller cities is the Micropolitan Statistical Area which is defined as an area with at least one urban cluster of at least 10,000 but less than 50,000 population, plus adjacent territory that has a high degree of social and economic integration with the core as measured by commuting ties. Metropolitan and Micropolitan Statistical Areas are defined in terms of whole counties and these two designations cover more than 45 percent of the total counties in the U.S and more than 94 percent of the U.S. population.[134]

As shown by the KDAQ-run ozone monitoring network in the Fiscal Year 2013 Annual Report, nearly all of the ozone monitors in Kentucky are located in Core Based Statistical Areas (CBSA) (i.e., the collective term for Metropolitan and Micropolitan Statistical Areas).[135] The location of ozone monitors in Kentucky reflects the fact that ozone formation is typically an urban phenomenon due to much higher densities of ozone precursor emission sources such as motor vehicle exhaust, large industrial facilities, and gasoline vapors in urban areas. In addition, EPA recommends that CBSAs serve as the starting point for determining the geographic boundaries of ozone nonattainment areas.[136] In the memorandum presenting this recommendation, EPA also indicates that ozone formation from anthropogenic sources is most closely tied to urban development.

Since Muhlenberg County is almost entirely rural and its airshed is not as significantly influenced by ozone precursor emissions from a nearby CBSA as the candidate monitors located in MSAs, the process for selecting a representative ozone monitor should consider population and the types of ozone precursor emissions sources that could influence the measured ozone concentrations at the candidate monitor locations.

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[133] U.S. Census Bureau, State & County QuickFacts, available at http://quickfacts.census.gov/qfd/index.html.
[134] Executive Office of the President, Office of Management and Budget, *Update of Statistical Area Definitions and Guidance on Their Uses*, November 20, 2008.
[135] Kentucky Division for Air Quality, *Fiscal Year 2013 Annual Report*, available at http://air.ky.gov/Division%20Reports/DAQ%202013%20Annual%20Report.pdf
[136] Memorandum from Robert J. Meyers, Principal Deputy Assistant Administrator, EPA Office of Air and Radiation to Regional Administrators, Regions I-X, *Area Designations for 2008 Revised Ozone National Ambient Air Quality Standards*, December 4 2008.

Figure 7-2. Candidate Ozone Ambient Monitoring Sites for Determining Background Ozone Concentrations Based on Proximity and Data Availability

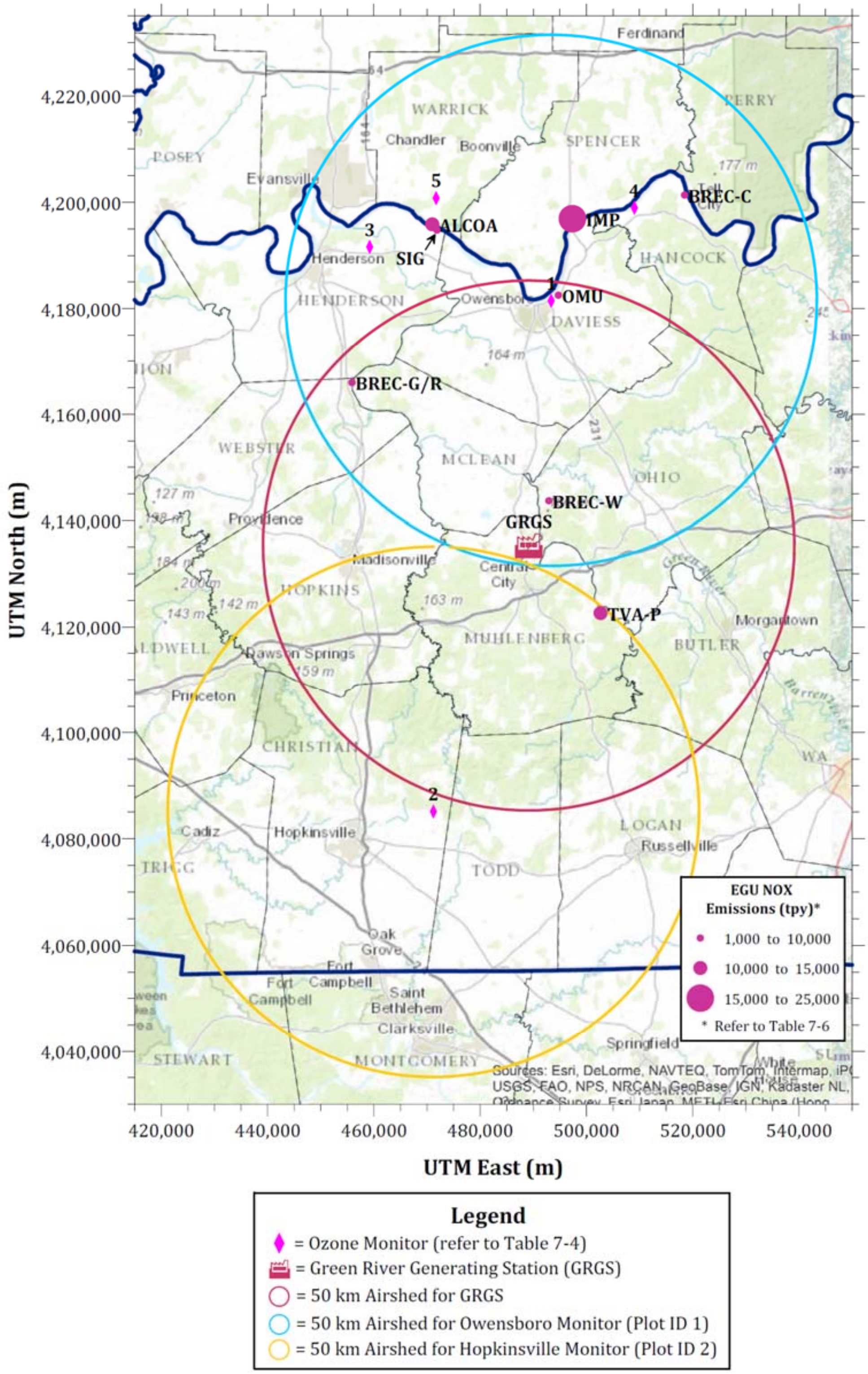
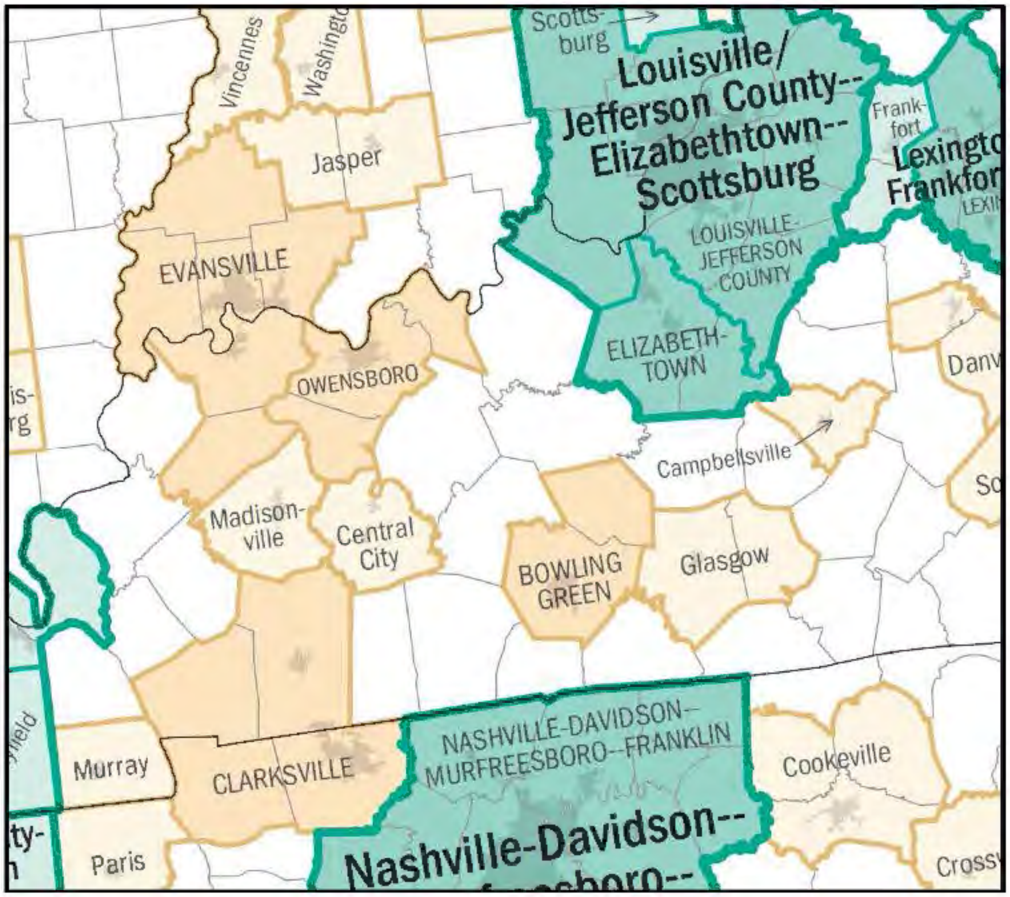
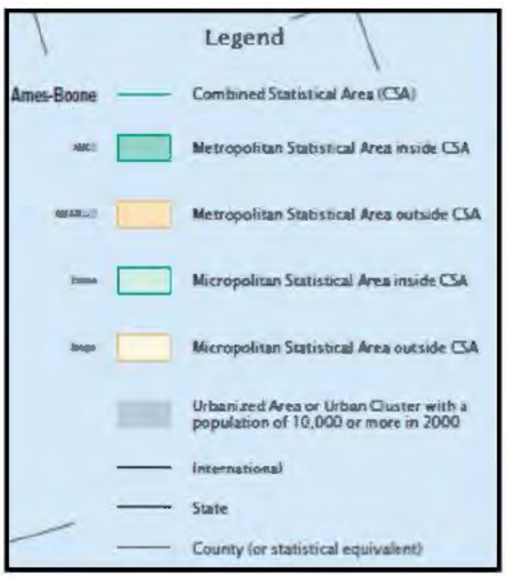


Figure 7-3. Metropolitan and Micropolitan Statistical Areas in Western Kentucky[137]





[137] U.S. Census Bureau, Combined Statistical Areas of the United States and Puerto Rico, November 2008, available at http://www.census.gov/population/www/metroareas/metroarea.html

Figure 7-4. Population and NO_X Emissions Comparisons between 50 km Regions Surrounding GRGS and Candidate Ozone Monitoring Stations

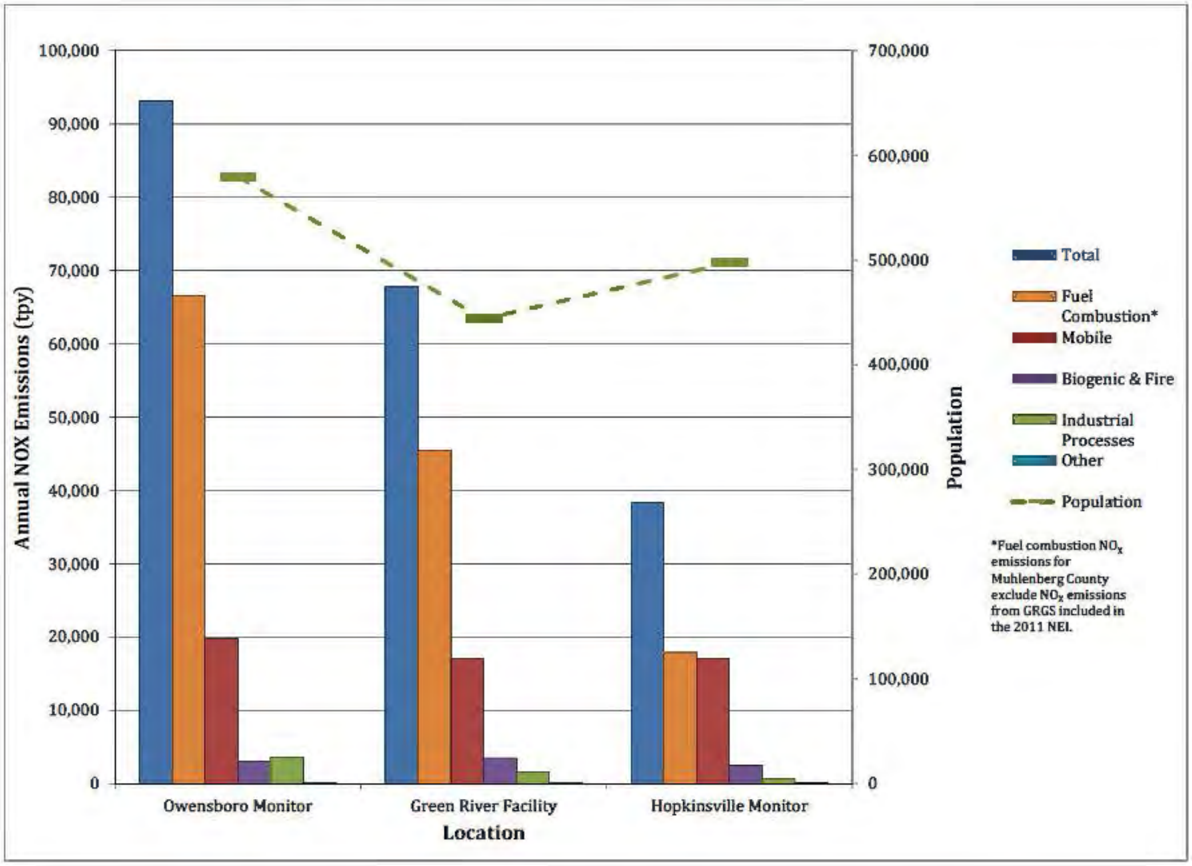
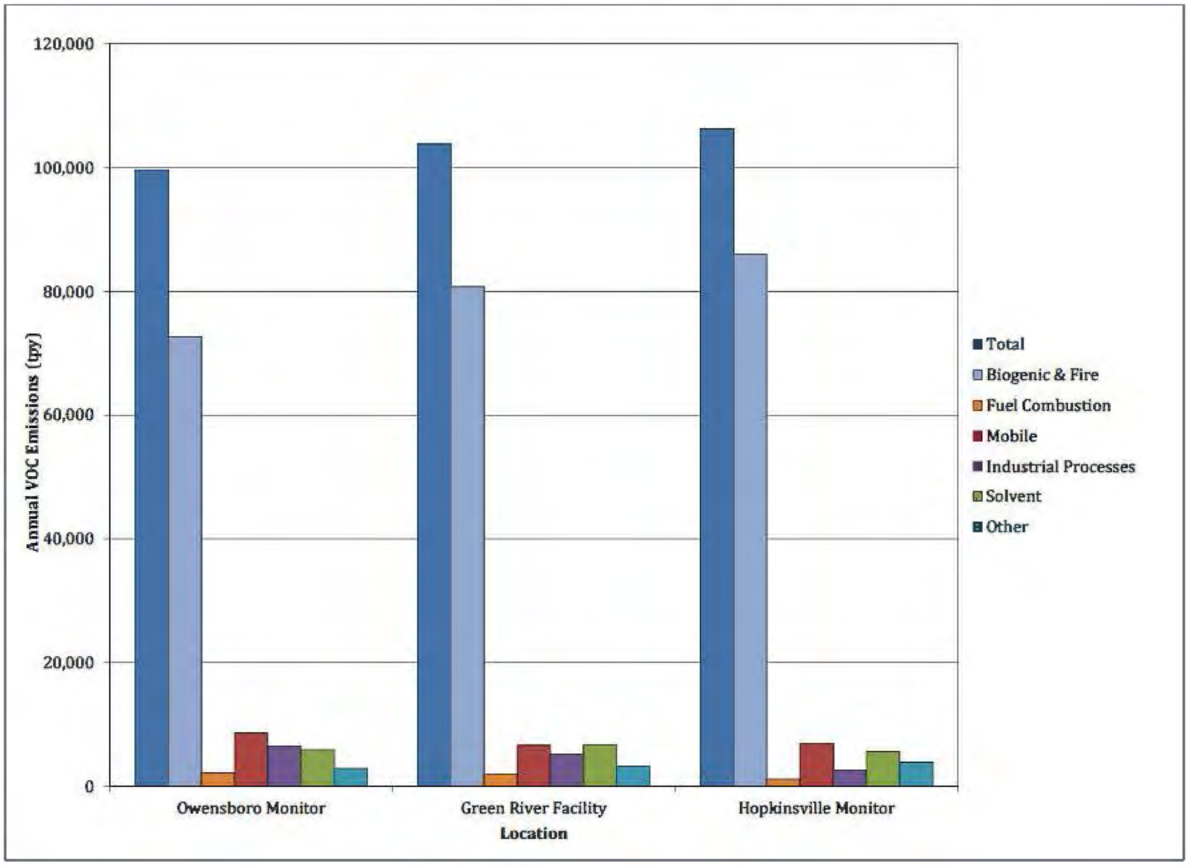


Table 7-6. 2011 National Emissions Inventory Annual NO_X Emission Rates for Coal-fired Electric Generating Units in Proximity to GRGS

Site Name	Short Name	County	City	State	2011 NEI Annual NO_X Emissions (tpy)
Owensboro Municipal Utilities - Elmer Smith Station	OMU	Daviess	Owensboro	KY	4,056
Big Rivers Electric Corp. (BREC) - Coleman Station	BREC-C	Hancock	Hawesville	KY	6,715
Tennessee Valley Authority (TVA) - Paradise Fossil Plant	TVA-P	Muhlenberg	Drakesboro	KY	10,148
BREC - Wilson Station	BREC-W	Ohio	Centertown	KY	1,117
BREC - Green Station	BREC-G	Webster	Sebree	KY	4,076
BREC - Reid HMP&L Station 2	BREC-R	Webster	Robards	KY	1,225
Indiana Michigan Power-Rockport	IMP	Spencer	Rockport	IN	21,841
Alcoa APGI - Warrick Power Plant	ALCOA	Warrick	Newburgh	IN	11,201
Sigeco - F.B. Culley Generating Station	SIG	Warrick	Yankeetown	IN	2,383
TVA- Cumberland Fossil Plant	TVA-C	Stewart	Cumberland City	TN	4,761

Figure 7-5. VOC Emissions Comparisons between 50 km Regions Surrounding GRGS and Candidate Ozone Monitoring Stations



7.6.2.3. Evaluation of Candidate Monitoring Stations

Beginning with the closest monitoring site to the GRGS, the following subsections discuss the population, ozone precursor emissions, and land use for each candidate ozone monitor. If a candidate monitor is rejected on the basis of a dissimilar airshed with respect to ozone formation, the next closest monitor is evaluated until a representative monitoring station is identified.

Evaluation of Monitoring Station in Daviess County

The Daviess County ozone monitor (Site ID 21-059-0005) is located approximately 3 km east of the Owensboro city center in a residential area just south of the Ohio River. Daviess County covers a total area of 458 square miles, has a population of 97,847, and has a corresponding population density of 213 persons per square mile (ranking Daviess County as the 7th most populous county from among Kentucky's 120 total counties).[138] Daviess County is classified under the 2013 Rural-Urban Continuum Codes as a "metro - counties in metro areas of fewer than 250,000 population."[139] As shown in Figure 7-3, Daviess County contains the core of the Owensboro MSA which consists of Daviess, McClean, and Hancock Counties and has a population of 116,030.[140] Visual inspection

[138] U.S. Census Bureau, State & County QuickFacts: Daviess County, Kentucky, available at: http://quickfacts.census.gov/qfd/states/21/21059.html
[139] U.S. Department of Agriculture Economic Research Service, 2013 Rural-Urban Continuum Codes for Kentucky, available at http://www.ers.usda.gov/data-products/rural-urban-continuum-codes.aspx.
[140] U.S. Census Bureau, Annual Estimates of the Population of Metropolitan and Micropolitan Statistical Areas: April 1, 2010 to July 1, 2012, available at http://www.census.gov/popest/data/metro/totals/2012/

of the 2006 National Land Cover Dataset, high resolution aerial photography, and topographic maps for Daviess County and the surrounding airshed reveals that the area contains a significantly higher fraction of urban/suburban development associated with the three (3) urbanized areas within the region (i.e., Evansville, Henderson, and Owensboro) than the GRGS airshed.[141] Several transportation corridors traverse across the airshed for the Daviess County monitor to connect the population centers in Owensboro, Evansville, and Henderson. In contrast to the GRGS airshed, the majority of the undeveloped land is devoted to agriculture (pasture/hay and cultivated crops in the NLCD 2006 classification scheme) rather than deciduous forests.

As shown in Figure 7-4, the population within the Daviess County monitor airshed according to the U.S. Census Bureau is 579,791, which is 30 percent higher than the population of the GRGS airshed.[142] The area-wide NO_X emissions for the Daviess County airshed documented in the 2011 NEI are 93,189 ton per year (which represents a 38 percent higher NO_X emission rate than in the GRGS airshed). The majority of the total NO_X emissions in the Daviess County airshed are generated from Fuel Combustion. Of the 66,607 tpy NO_X emissions contribution from the Fuel Combustion sector, over 90 percent of the emissions are attributable to the coal-fired EGU listed in Figure 7-2 and Table 7-6. The Indiana Michigan Power (IMP) Rockport Generating Station and the Alcoa APGI Warrick Power Plant contribute more than 33,000 tpy of NO_X emissions to the area-wide total. Each of the EGU located in close proximity to the Owensboro monitor (i.e., Alcoa, IMP, OMU, BREC-G/R) are located more than 45 km north/northwest of the GRGS. Based on this orientation, NO_X emissions transport from these EGU to the area surrounding the GRGS is not expected to occur given the direction of the prevailing winds during ozone season (from the south or southwest to the north or northeast).[143] However, transport of NO_X emissions from these EGU to the Daviess County monitor is expected to occur, such that any secondarily formed ozone attributable to these NO_X emissions would impact measured ozone concentrations at the Daviess County monitor. Another feature of the Daviess County monitor which is not considered to be representative of the area surrounding the GRGS is its direct exposure to ozone formation caused by local commuter traffic. As an urban scale ozone monitor with the objective of measuring the maximum ozone concentration (refer to Table 7-5), the Daviess County monitor was likely, intentionally located just outside the Owensboro urbanized area boundary in the downwind direction of the prevailing winds. This orientation would expose the monitor to the highest level of mobile source NO_X emissions and any associated ozone formation that these emissions may cause.

The area-wide VOC emissions for the Daviess County airshed from the 2011 NEI are 99,657 tpy, with emissions from biogenic sources and fires representing more than 70 percent of the VOC emissions total. Similar to the GRGS airshed, anthropogenic VOC emissions in the Daviess County airshed are predominantly generated by mobile sources, industrial processes, and solvent usage, but these sources only comprise a relatively small fraction of the total VOC emissions that could potentially affect ozone formation in the area. Figure 7-5 demonstrates the Daviess County and GRGS airsheds share similar characteristics with respect to VOC emissions due to the relatively constant influence from biogenic VOC emissions. Rural and moderately developed urban/suburban areas of the Southeast U.S. have relatively high biogenic VOC emissions as compared to Western and Midwestern states. These high biogenic VOC emission rates are attributable to the high densities of deciduous forests which characterizes much of the land use in rural areas of the Southeast. Deciduous trees emit a highly reactive biogenic hydrocarbon called isoprene. Isoprene is a major contributor to ozone formation because it can act to catalyze ozone forming photochemical reactions.[144] The high densities of forested land in

[141] Refer to red circle in Figure 7-2 for 50 km region defining the airshed for the Daviess County monitor. Counties in this 50 km region include Breckenridge, Daviess, Hancock, Henderson, Hopkins, McClean, Muhlenberg, Ohio, and Webster Counties in Kentucky and Perry, Spencer, Vanderburgh, and Warrick Counties in Indiana.
[142] U.S. Census Bureau, State & County QuickFacts, available at http://quickfacts.census.gov/qfd/index.html.
[143] USDA, National Resources Conservation Service, Wind Rose Data for Evansville Indiana, http://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/
[144] EPA, Biogenic Ozone-Precursors: From Mechanism to Algorithm, Air Quality (1996), available at http://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract/696/report/0

the Southeast leads to relatively homogenous biogenic VOC emissions across large areas of the region including Western Kentucky.

Through the Empirical Kinetic Modeling Approach (EKMA) and other similar ozone formation prediction schemes, EPA has recognized for decades that high biogenic VOC emissions in rural areas and heavily forested locations downwind of urban and suburban areas create a "NO_X-limited" atmospheric chemistry regime, whereby changes in anthropogenic VOC emissions have negligible impacts on ozone formation.[145] In a NO_X-limited regime, reductions in NO_X emissions have the highest tendency to reduce ozone concentrations, and thus, air quality agencies implement control strategies with a focus on NO_X emissions reductions in these areas. In contrast, ozone formation in large urban core-areas (e.g., Chicago, Philadelphia, New York, etc.) with high population densities is VOC-limited, and air quality agencies accordingly target VOC emissions reductions to reduce ozone concentrations in these areas. Recent studies evaluating VOC/NO_X concentration ratios in Western Kentucky and Southeastern Indiana clearly indicate both the Daviess County and GRGS airsheds are expected to be predominantly NO_X-limited.[146] [147] Therefore, the VOC emissions profile of these two areas should not be used as a metric for assessing representativeness, and the previous discussion regarding differences in the NO_X emission profile should carry more weight in the representativeness analysis.

Given the significant differences in population and NO_X emissions profile between the Daviess County airshed and the GRGS airshed, ozone monitoring data from the Daviess County monitor located in the Owensboro MSA (and adjacent to the larger Evansville MSA) is not considered to be representative of the mostly rural areas surrounding the GRGS.

Evaluation of Monitoring Station in Christian County

The next closest Christian County ozone monitor (Site ID 21-047-0006) is located approximately 15 km east of the Hopkinsville city center in a remote rural area. Christian County covers a total area of 718 square miles, has a population of 75,427, and has a corresponding population density of 105 persons per square mile (ranking Christian County as the 11th most populous county from among Kentucky's 120 total counties).[148] Christian County is classified under the 2013 Rural-Urban Continuum Codes as a "metro - counties in metro areas of 250,000 to 1 million population," where the metro area referenced is Clarksville, Tennessee.[149] As shown in Figure 7-3, Christian County contains the urbanized area of Hopkinsville (with a population of 32,966) and a small portion of the city of Clarksville.[150] The Clarksville MSA, located approximately 40 km due south of the Christian County monitor, has a population of 274,342.[151] Although the Clarksville MSA has a higher population than Owensboro MSA (274,342 for Clarksville vs. 116,030 for Owensboro), the population within the Christian County monitor airshed (497,541) is 15 percent lower than the population within the Daviess County monitor airshed (579,791) (refer to Figure 7-4) and more comparable to the population within the GRGS airshed (443,788). Visual inspection of the 2006 National Land Cover Dataset, high resolution aerial photography, and topographic maps for Christian County and the surrounding airshed reveals that the area is dominated by deciduous forest with small areas of urban/suburban development associated with the two (2) urbanized areas

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[145] EPA, *Guideline on Ozone Monitoring Site Selection*, August 1998, EPA-454/R-98-002, Section 2.1 Ozone Formation Chemistry.
[146] Duncan et. al, *The Sensitivity of U.S. Surface Ozone Formation to NOX and VOCs as Viewed from Space*, Presented at the 8th Annual CMAS Conference, Chapel Hill, NC, October 19-21, 2009.
[147] Lake Michigan Air Directors Consortium, *VOC and NOx Limitation of Ozone Formation at Monitoring Sites in Illinois, Indiana, Michigan, Missouri, Ohio, and Wisconsin*, 1998-2002, February 24, 2003
[148] U.S. Census Bureau, State & County QuickFacts: Christian County, Kentucky, available at: http://quickfacts.census.gov/qfd/states/21/21047.html
[149] U.S. Department of Agriculture Economic Research Service, 2013 Rural-Urban Continuum Codes for Kentucky, available at http://www.ers.usda.gov/data-products/rural-urban-continuum-codes.aspx.
[150] City of Hopkinsville (http://www.hoptown.org/)
[151] U.S. Census Bureau, Annual Estimates of the Population of Metropolitan and Micropolitan Statistical Areas: April 1, 2010 to July 1, 2012, available at http://www.census.gov/popest/data/metro/totals/2012/

within the region (i.e., Hopkinsville and Clarksville).[152] A band of agricultural land located between Hopkinsville and Clarksville traverses through the center of the 50 km region defining the Christian County monitor's airshed. The degree of urban/suburban development in the Christian County monitor airshed is lower than the Daviess County monitor airshed due to the presence of only two (2) urbanized areas versus three (3) urbanized areas in the Daviess County monitor airshed.

The area-wide NO_X emissions for the Christian County airshed documented in the 2011 NEI are 38,292 ton per year. With fewer EGU located within the Christian County airshed, NO_X emissions from Fuel Combustion represent a significantly lower fraction of total NO_X emissions than they do in the Daviess County or GRGS airsheds. NO_X emissions from the Mobile Source sector are roughly equivalent to NO_X emissions from the Fuel Combustion sector, and these two (2) categories combined represent more than 90 percent of the total NO_X emissions affecting the airshed. Reflecting the more rural nature of the Christian County monitor location and the relatively large distances separating it from the nearest urbanized area, the Christian County monitor has a larger measurement scale (Regional Scale with a scale definition of 50 km to 100 km) and broader monitoring objective (Multiple including both ozone NAAQS compliance and interstate regional transport) than the Daviess County ozone monitor.[153] These monitor characteristics are consistent with a location that is not expected to be directly impacted by the urban ozone formation phenomenon associated with high population densities and vehicle traffic. Furthermore, both the GRGS and Christian County monitor are located upwind of the closest coal-fired EGU sources that have the potential to affect ozone formation (i.e., BREC-W and TVA-P, refer to Figure 7-2 and Table 7-6). A series of research papers evaluated in the Southern Oxidants Study (SOS) suggests ozone formation in power plant plumes does not occur effectively until the plume disperses sufficiently to fill the mixed layer of the atmosphere. This amount dispersion does not typically occur until the downwind transport distance exceeds 50 km.[154] Based on the prevailing winds during ozone season, any ozone formation attributable to Big Rivers Coleman Station (BREC-C) and TVA Paradise (TVA-P) would most likely occur in downwind counties located to the north or northeast of Muhlenberg and Christian County and not in the direct vicinity of the GRGS or the Christian County ozone monitor. In contrast, the Daviess County monitor is surrounded by several coal-fired EGU which are located in an orientation that is more conducive to ozone formation and transport to the monitor location.

The historical trend in ozone NAAQS design values obtained from the Christian and Daviess County ozone monitoring stations further supports the argument that the Daviess County monitor is being influenced by the dissimilar NO_X emissions profile of the airshed. In the period from 2010 to 2013, the Christian County monitor has recorded three-year average fourth highest 8-hr ozone concentrations (i.e., concentrations in the form of the 8-hr ozone NAAQS) that are on average 5 ppb lower than the Daviess County monitor. A 5 ppb difference in ozone NAAQS design values is a significant difference given the state-wide range across all 26 monitors in Kentucky for 2012 was only 21 ppb (lowest design value for Bell County monitor is 0.065 ppm and highest design value for Oldham County monitor is 0.086 ppm).[155] The direct correlation between NO_X precursor emissions and measured ozone concentrations demonstrated by this monitoring data trend is an expected observation from a NO_X-limited regime. Figure 7-4 demonstrates the population and NO_X emissions profile of the GRGS airshed is more similar to the Christian County monitor airshed than the Daviess County monitor airshed, and therefore, the measured ozone concentrations in the GRGS and Christian County monitor airsheds are expected to be more similar as well. Considering the proximity, data availability, and similarities of ozone

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[152] Refer to red circle in Figure 7-2 for 50 km region defining the airshed for the Christian County monitor. Counties in this 50 km region include Butler, Caldwell, Christian, Hopkins, Logan, Muhlenberg, Todd, and Trigg Counties in Kentucky and Montgomery, Robertson, and Stewart Counties in Indiana.

[153] KDAQ, *Kentucky Annual Ambient Air Monitoring Network Plan 2013*, July 1, 2013.

[154] Ellis B. Cowlings and Cari Furiness, The State of the Southern Oxidants Study (SOS) Policy Relevant Findings in Ozone and $PM_{2.5}$ Pollution Research 1995-2003, Section 2.3 Ozone Formation in Power Plant Plumes, June 30, 2004.

[155] Kentucky Division for Air Quality, *Fiscal Year 2013 Annual Report*, available at http://air.ky.gov/Division%20Reports/DAQ%202013%20Annual%20Report.pdf

precursor emission profiles of the potential ozone monitoring locations in Table 7-4, KU has chosen the Christian County monitor for estimating the ozone background concentration.

7.6.2.4. Selection of Representative Monitoring Station

KU proposes to use the Christian County monitoring station for estimating the ozone background concentration in lieu of conducting pre-construction monitoring. The average fourth highest 8-hour average concentrations for the most recent three years of ozone monitoring data (i.e., 2011 to 2013) for the Christian County monitoring station is shown in Table 7-7. KU requests that KDAQ waive the pre-construction monitoring requirements of 401 KAR 51:017 Section 11 for the proposed project based on the availability of representative monitoring data from this ozone monitoring station.

Table 7-7. Selected Ozone Background Concentration

Site ID	Location	County	State	Distance and Direction to Green River Station	8-hr Average Ozone Concentration[1] (ppm)
21-047-0006	Hopkinsville	Christian	Kentucky	53.3 km NNE	0.069

[1] Three-year average (2011-2013) of the 4th highest 8-hr average concentrations.

7.6.3. Non-Modeling Evaluation of Ozone Impacts

With a representative background ozone concentration established, the remaining step in the ozone ambient impact analysis is to estimate the potential increase in ozone formation that may be attributable to the proposed project. Recognizing the regional nature of ozone formation, EPA does not require single source ozone impacts to be quantified in most cases and frequently accepts qualitative approaches for demonstrating NO_X and VOC emissions increases from a proposed project will not cause or contribute to a violation of the ozone NAAQS. In light of this precedent, KU has devised a reasonable, qualitative approach for estimating the ozone formation potential of the GRGS's changes in NO_X and VOC emissions.

Under this approach, the NO_X and VOC emissions increases from the proposed project are expressed as a percentage of the total NO_X and VOC emissions from counties within 50 km of the selected Christian County background monitor. The 50 km distance was selected rather than just the county or MSA within which the site is located because ozone formation is a regional phenomenon and this is the maximum distance over which near-field Class II Area air quality analyses are typically conducted. The percentage change in ozone precursor emissions attributable the proposed is then used to determine the effect on ozone concentrations in the area surrounding the GRGS based on the conservative assumption that the full NO_X and VOC emission changes from the RGS affect ozone formation on a directly proportional basis. The post-project ozone concentration derived from the current background concentration plus the change in ozone concentration attributable to the proposed project is then compared against the 8-hr ozone NAAQS to demonstrate the project does not cause or contribute to a violation of the NAAQS.

According to the 2011 NEI, the total NO_X and VOC emissions for counties within 50 km of the Christian County ozone monitoring site are 38,292 tpy and 106,305 tpy, respectively (refer to Figures 7-4 and 7-5). The worst case NO_X and VOC emissions changes attributable the NGCC project are -534.7 tpy and 201.7 tpy, respectively (refer to Table 4-1). This GRGS ozone precursor emission data equates a 1.4 percent decrease in NO_X emissions and a 0.19 percent increase in VOC emissions over the current baseline emissions from counties within 50 km of the Christian County monitor. With a larger percentage decrease in airshed-wide NO_X emissions caused by the project than the percentage increase in VOC emissions, the proposed NGCC project is more likely to improve ozone air quality than it is to adversely affect ozone air quality, especially considering the NO_X-limited regime characterizing both the GRGS and Christian County monitor airsheds. Based on this information, the emissions changes resulting from the NGCC project will not cause or contribute to a violation of the ozone NAAQS.

7.7. ADDITIONAL IMPACTS ANALYSIS

Pursuant to 401 KAR 51:017 Section 13, three additional impacts analyses were performed as part of this PSD permitting action. These are: 1) a growth analysis, 2) a soil and vegetation analysis, and 3) a visibility analysis.

7.7.1. Growth Analysis

The purpose of the growth analysis is to quantify project associated growth; that is, to predict how much new growth is likely to occur in order to support the source or modification under review, and then to estimate the air quality impacts from this growth. Since the GRGS is an existing facility and the proposed project is not expected to increase full-time employment after the construction phase of the project is completed, the proposed project is anticipated to have a limited growth impact on Muhlenberg County, Kentucky. Approximately 500 construction workers are expected to be employed during the approximately 3 year construction phase of the project. Many of these workers will already reside and conduct business in the region surrounding the GRGS, and thus would not cause growth-related air quality impacts. While some workers employed during the construction phase of the project are likely to currently reside outside the region and thus may commute to the area, any related potential air quality impacts from these out-of-town workers are too small to be reasonably quantifiable.

7.7.2. Impacts on Soils and Vegetation Analysis

The EPA developed the secondary NAAQS to protect certain air quality related values (i.e., soil and vegetation) that may not be sufficiently protected by the primary NAAQS. There are no secondary NAAQS for CO; therefore, to assess soil and vegetation impacts, Significance Analysis impacts were compared against conservative screening levels provided in the EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*.[156] Screening concentrations for exposure to ambient air concentrations are presented in Table 3.1 of the EPA *Screening Procedure* document at 1,800,000 μg/m^3 for sensitive soils and vegetation and 18,000,000 μg/m^3 for resistant soils and vegetation, both of which are based on weekly average concentrations. The maximum predicted impact for comparison with these screening thresholds is 11,378 μg/m^3. This value was calculated by conservatively summing the highest 1-hour average model predicted concentration over the 2009-2013 time period (1,892 μg/m^3) and a conservatively high estimated background concentration based on the high second high monitored concentration in the three-year period from 2011 to 2013 (9,486 μg/m^3) from the CO monitor located on 11th Street in Evansville, Indiana (AQS Site ID: 18-163-0022). The maximum 1-hour average model predicted concentration is used to compare with the weekly average screening thresholds because no weekly averaging period is available in AERMOD. Additionally, the CO monitor sited in Evansville, Indiana while located relatively nearby the GRGS is located in a much more urbanized area, with expected ambient CO concentrations greater than would be expected at the GRGS. For these two reasons, the concentration provided above for comparison with the screening thresholds is very conservative; thus, there are no adverse impacts expected on soils or vegetation as a result of the proposed project.

[156] EPA, Office of Air Quality Planning and Standards, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants Soils and Animals*, Research Triangle Park, North Carolina, December 1980.

7.7.3. Visibility Analysis

The KAR provides no specific prohibitions against visibility impairment other than regulations limiting source opacity, pursuant to 401 KAR 59:010 Section 3 (1) a, and protecting visibility at federally protected Class I areas, pursuant to 401 KAR 51:017 Section 14. All existing and proposed sources at the GRGS will now and in the future maintain compliance with applicable opacity restrictions. Therefore, visibility impairment at any off-site location would not be expected. In addition, CO, VOCs and GHGs, which are the pollutants for which PSD review is triggered for this project, are not visibility affecting pollutants; therefore, a detailed Class II area visibility analysis has not been completed as part of this application.

8. TOXIC AIR POLLUTANT RISK ASSESSMENT

Kentucky's narrative air toxics regulation, 401 KAR 63:020, applies to affected facilities which emit or may emit potentially hazardous or toxic substances ("TAP") as defined in the regulation, provided that the emissions are not elsewhere subject to KDAQ regulation. The regulation requires the utmost care and consideration in handling potentially hazardous or toxic substances and provides for KDAQ evaluation of a facility's emission potential and sufficiency of controls and procedures. Although not a requirement of the PSD program, KU has performed an analysis of the project TAP emissions pursuant to 401 KAR 63:020 as part of this application.

8.1. KENTUCKY AIR TOXICS REGULATION APPLICABILITY

The specific requirements of 401 KAR 63:020 imposed for a given permit action are generally determined on a case-by-case basis by KDAQ. These requirements are based on several factors, such as TAP emission rates, TAP emissions source characteristics, and the proximity of major TAP emissions sources to sensitive receptors. Although KU believes that TAP emissions from the proposed NGCC plant at GRGS are sufficiently low and have limited toxicity such that a quantitative evaluation of air toxics impacts should not be required for this permit action, KU proactively chose to complete a supplemental dispersion modeling analysis of all TAP emissions sources emitted by the proposed project, with the exception of the fire pump and emergency generator engines, which are elsewhere subject to KDAQ regulation through 40 CFR 63 Subpart ZZZZ. The results of this analysis demonstrate that no adverse ambient impacts on the health and welfare of humans, animals, and plants are expected from the maximum calculated TAP emissions from the modified facility.

8.2. AIR TOXICS HUMAN HEALTH RISK ASSESSMENT

Conceptually, a human health risk assessment compares dose-response values for adverse health effects with the results of an air dispersion model that estimates inhalation exposures of human populations to ambient concentrations of potentially hazardous air contaminants. Chronic (i.e., long-term) exposures to a specific pollutant have the potential to lead to both cancerous and non-cancerous effects.

For 401 KAR 63:020, KDAQ has currently deferred to using the chemical-specific data found in the U.S. EPA Region 9 Regional Screening Level (RSL) Summary Table, if available, as a benchmark for the acceptable thresholds in their Air Toxics program as described on KDAQ's air toxics website.[157] [158]

To characterize possible chronic risks for non-carcinogenic compounds using dispersion model results, a hazard quotient (HQ) and a total Hazard Index (HI) are calculated. If an individual HQ or cumulative HI is less than the hazard target level of 1.0 adverse health effects are considered unlikely, even over a lifetime of exposure.[159] However, an HI greater than 1.0 does not necessarily suggest a likelihood of adverse effects. A respiratory HI greater than 1.0 can be best described as indicating that a potential may exist for adverse health effects which may indicate the need for further analysis.

To characterize risks associated with carcinogenic compounds, the inhalation unit risk (IUR) by pollutant must be taken into consideration. The value of risk is unitless and represents a quantitative assessment of cancer causing potential per concentration of air inhaled, expressed as an upper bound probability that a person may

[157] http://air.ky.gov/Pages/AirToxics.aspx
158 U.S. EPA Region 3 Mid-Atlantic Risk Assessment, Risk-Based Screening Table, November 2013 (available at http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/Generic_Tables/index.htm)
[159] U.S. EPA *Air Toxics Risk Assessment Library Volume 2 – Facility-specific Assessment*, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, April 2004, EPA-453-K-04-001B.

develop cancer over the course of his or her lifetime because of their exposure to that TAP. A typical evaluation initially assumes a lifetime risk to a healthy adult with constant exposure 8,760 hours per year for 70 years. Finally, the cumulative impact of all carcinogenic HAP/TAPs is calculated by summing the cancer risk posed by each individual carcinogenic HAP/TAP. This sum is then compared to a cancer risk range defining the incremental chance an individual will develop cancer in their lifetime as a result of exposure, which EPA has established for the purposes of Section 112 residual risk evaluations in the range of one in one million (e.g., 1 x 10^{-6}) to one in ten thousand (e.g., 1 x 10^{-4}).

8.3. CHRONIC RISK ASSESSMENT METHODOLOGY

The chronic risk assessment methodology takes human exposure frequency into account when determining risk thresholds. The chronic risk thresholds for both non-cancerous and cancerous impacts were assessed for the maximum impacted receptor outside the facility fenceline.[160]

As stated above, the chronic non-cancerous individual HQ for each TAP and cumulative HI for all TAPs must be less than 1.0 in order to demonstrate that no adverse health effects will result. The chronic HQ and HI are typically calculated using the following equations:

$$HQ_j = EC_{NCj} \div RSL_{NCj}$$
$$HI = \sum HQ_j$$

In these equations, HQ_j is the chronic hazard quotient for an individual HAP/TAP, EC_{NCj} is the continuous inhalation exposure to an individual HAP/TAP based on annual average dispersion modeling results, RSL_{NCj} is the non-carcinogenic resident air screening level for an individual HAP/TAP, and *HI* is the cumulative chronic hazard index. If the HI falls below 1.0, no adverse impacts are anticipated from the modeled source.

To characterize the risks associated with carcinogenic compounds, annual maximum modeled concentrations should be directly compared with the appropriate cancerous residential air RSL. The cancerous RSL threshold is based on the maximum annual concentration that an individual can be exposed to and still maintain an acceptable cancer risk of less than one in one million. The individual and cumulative cancer risk are typically calculated using the following equations:

$$Risk_j = EC_{Lj} \div RSL_{Cj}$$
$$Risk_T = \sum Risk_j$$

In these equestions, $Risk_j$ is the individual cancer risk for an individual HAP/TAP expressed as an upper bound risk of contracting cancer over a lifetime, EC_{Lj} is the lifetime estimate of continuous inhalation exposure to an individual HAP/TAP based on annual average dispersion modeling results, RSL_{Cj} is the cancerous resident air screening level for an individual HAP/TAP, and $Risk_T$ is the total individual cancer risk. Because the resident air cancer RSL is already normalized to a cancer risk threshold of one in one million, a total risk below 1.0 indicated no adverse impacts from the modeled source.

Rather than conducting a separate modeling scenario for each emitted TAP where each source would be modeled at the potential emission rate for the individual TAP considered, KU modeled the cumulative risk adjusted TAP emission rate from each source for each component of the risk assessment (non-cancer and cancer

[160] Note that assessing risk at all receptor locations outside the facility fenceline is conservative, as impacts may be assessed for the nearest residence to the facility.

risk assessments). The cumulative risk-adjusted potential emission rate from each emission unit considered in the non-cancer chronic risk assessment was calculated as follows (refer to Appendix I):

σ

σ $$ER_{NC_i}\ [(g/s)/(\mu g/m^3)] = \sum_{j=1}^{n} ER_{A_j}/RSL_{NCj} \qquad (15)$$

σ where,

ER_{NC_i} = Cumulative risk - adjusted emission rate for non - cancer chronic risk assessment $[(g/s)/(\mu(/m^3)]$

n = Number of HAP/TAPs with an RSL emitted by emission unit i

σ j = Individual HAP/TAP j

ER_{A_j} = Maximum annual average potential emission rate of HAP/TAP j (g/s)

RSL_{NCj} = Non - cancer RSL value for TAP j

The cumulative risk-adjusted potential emission rate from each emission unit considered in the cancer risk assessment was calculated as follows (refer to Appendix I):

σ

σ $$ER_{C_i}\ [(g/s)/(\mu g/m^3)] = \sum_{j=1}^{n} ER_{A_j}/RSL_{Cj} \qquad (15)$$

σ where,

ER_{C_i} = Cumulative risk - adjusted emission rate for cancer risk assessment $[(g/s)/(\mu(/m^3)]$

n = Number of HAP/TAPs with an RSL emitted by emission unit i

j = Individual HAP/TAP j

ER_{A_j} = Maximum annual average potential emission rate of HAP/TAP j (g/s)

RSL_{Cj} = Cancer RSL value for TAP j

8.4. CHRONIC RISK ASSESSMENT RESULTS SUMMARY

The modeling methodologies (e.g., meteorological data, receptor grids, source parameters, buildings, terrain elevations) described in Section 7 of this application were also used in the risk assessment dispersion modeling analysis. Refer to Appendix I for the complete TAP emissions inventory for all 401 KAR 63:020 affected TAP emissions sources associated with the NGCC plant at GRGS.

When risk-adjusted emission rates are modeled in AERMOD, the model output is risk (i.e., a ratio of modeled concentration to risk threshold) rather than concentration. For example, the maximum annual-average formaldehyde potential emission rate from the auxiliary boiler is 9.46E-04 g/s and the non-cancer residential air RSL for formaldehye is 10 $\mu g/m^3$ which gives a risk-adjusted emission rate of 9.46E-05 $(g/s)/(\mu g/m^3)$ (refer to Appendix I). This risk-adjusted emission rate for formaldehyde is then added to the risk-adjusted emission rates for all other TAPs emitted by the auxiliary boiler with a non-cancer RSL, which gives a cumulative risk-adjusted emission rate of 1.23E-03 $(g/s)/(\mu g/m^3)$.

Based on this risk-adjusted emission rate approach, Table 8-1 presents the cumulative (where, cumulative refers to the inclusion of all modeled sources) non-cancer risk results output directly by AERMOD for comparison against the HI threshold level of 1.0. Table 8-2 presents the cumulative cancer risk results output directly by AERMOD for comparison against the cancer risk threshold of 1.0. The maximum non-cancer and cancer risks predicted at an offsite receptor represent only a small fraction of the HI and cancer risk thresholds, which demonstrates HAP/TAP emissions from the NGCC plant are not expected to pose an adverse risk to human health and welfare. The risk assessment results presented below are overly conservative in nature and therefore provide added assurance that emissions of TAPs from new sources at the GRGS NGCC plant would not result in an adverse impact. In this analysis, the location of the maximum off-site impact was used to determine both non-cancerous and cancerous chronic impacts. The maximum impact predicted to occur at a receptor along the facility property line is an "area" where people are unlikely to spend a significant amount of time. Since chronic exposures only occur when people are exposed to unacceptable concentrations over a period of years or longer, it is extremely unlikely that the predicted impacts shown in this analysis will actually be experienced by any one individual. Also, non-cancer risk assessment, HIs are only determined by summing the HQs of pollutants that affect the same target organ or physiological system and not by summing the HQs of all emitted pollutants, as was done in this analysis. The approach used here results in an over estimate of the HIs and is therefore overly conservative. These conservative results provide an affirmative determination that potential emissions of HAP/TAPs from the modified facility would not result in impacts that would adversely affect human health and welfare.

Table 8-1. Non-Cancer Chronic Risk Assessment Results

Averaging Period	Year for Met. Data	Hazard Index (HI) Threshold	Maximum Noncancer HI	UTM East[a] (m)	UTM North[a] (m)
Annual	2009		0.0081	488,976.10	4,136,109.40
	2010		0.0069	489,048.70	4,136,178.20
	2011		0.0087	489,048.70	4,136,178.20
	2012		0.0094	488,903.50	4,136,040.60
	2013		0.0084	488,976.10	4,136,109.40
	Max. of 5 Years	**1.0**	**0.0094**	488,903.50	4,136,040.60

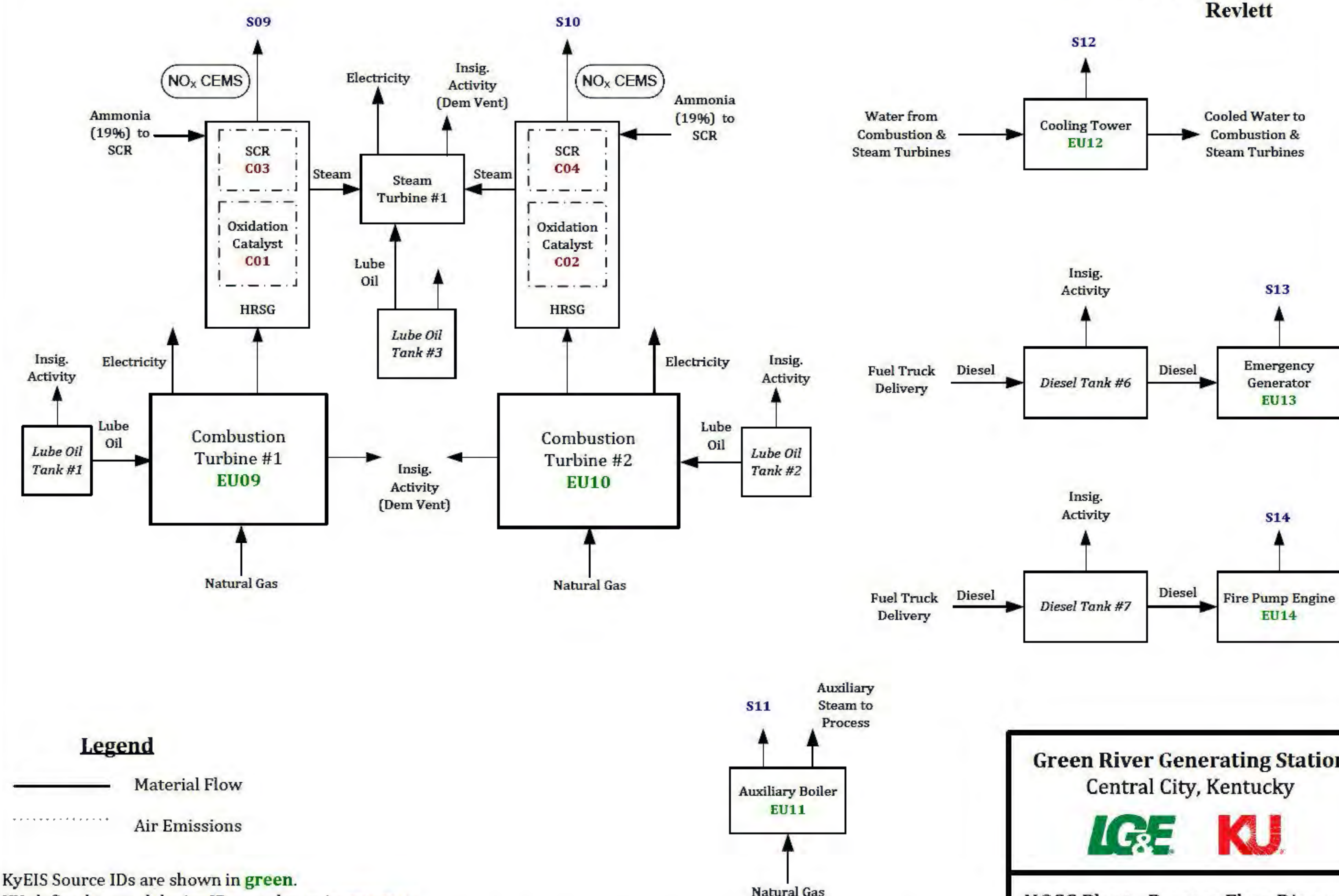
[a] UTM coordinates are in NAD83.

Table 8-2. Cancer Risk Assessment Results

Averaging Period	Year for Met. Data	Cancer Risk Threshold	Maximum Cancer Risk	UTM East[a] (m)	UTM North[a] (m)
Annual	2009		0.0918	488,605.10	4,134,997.90
	2010		0.0883	488,605.10	4,134,997.90
	2011		0.0860	488,605.10	4,134,997.90
	2012		0.0990	488,605.10	4,134,997.90
	2013		0.0883	488,605.10	4,134,997.90
	Max. of 5 Years	**1.0**	**0.0990**	488,605.10	4,134,997.90

[a] UTM coordinates are in NAD83.

APPENDIX A: FACILITY INFORMATION



KyEIS Source IDs are shown in green.
KU-defined control device IDs are shown in maroon.
KU-defined emission point IDs are shown in blue.
Existing emission units and the following units associated with the NGCC plant project are not depicted: Fuel Gas Heater (EU15), Circuit Breakers, and Fugitive Components.
Note that SCR will be installed only if combustion turbine option A or C is selected.

Green River Generating Station
Central City, Kentucky

LG&E KU

NGCC Plant - Process Flow Diagram

Trinity Consultants

131801.0073
March 2014

FACILITY LEGEND

1. COMBUSTION TURBINE
2. HEAT RECOVERY STEAM GENERATOR
3. STEAM TURBINE BUILDING
4. HRSG STACK
5. ADMINISTRATION/CONTROL BUILDING
6. GAS YARD
7. GAS COMPRESSOR BUILDING
8. CIRC. WATER CHEMICAL FEED BUILDING
9. EMERGENCY GENERATOR *
10. DEMIN WATER STORAGE TANK
11. EXISTING SUBSTATION
12. GSU TRANSFORMER
13. SWITCHYARD
14. COOLING TOWER
15. WAREHOUSE/MAINTENANCE SHOP
16. WATER TREATMENT BUILDING
17. WATER PRETREATMENT AREA
18. UNIT AUX TRANSFORMERS
19. SERVICE/FIRE WATER STORAGE TANK
20. FIRE PROTECTION PUMP HOUSE
21. AUXILIARY BOILER BUILDING

FACILITY GRADE NOTES

BASE POWERBLOCK ELEVATION = 440' ASL
BASE WATER TREATMENT AREA ELEVATION = 445' ASL
BASE COOLING TOWER ELEVATION = 435' ASL
BASE SWITCHYARD ELEVATION = 440' ASL

EMISSION POINTS

EMISSION POINT No. (EPN)	NAME	SPCS NAD83 (FEET)	UTM ZONE 16 (METERS)	HEIGHT ABOVE GRADE (FEET)
1	HRSG 1 STACK	N2018929.0 E1240910.0	N4135367 E488954	180
2	HRSG 2 STACK	N2018775.0 E1241004.0	N4135321 E488983	180
3	COOLING TOWER CELL 1	N2019001.6 E1241050.9	N4135390 E488996	64
4	COOLING TOWER CELL 2	N2019032.5 E1241101.9	N4135400 E489012	64
5	COOLING TOWER CELL 3	N2018953.9 E1241079.7	N4135376 E489005	64
6	COOLING TOWER CELL 4	N2018984.8 E1241130.7	N4135385 E489021	64
7	COOLING TOWER CELL 5	N2018906.2 E1241108.6	N4135361 E489014	64
8	COOLING TOWER CELL 6	N2018937.2 E1241159.6	N4135371 E489030	64
9	COOLING TOWER CELL 7	N2018858.6 E1241137.5	N4135347 E489023	64
10	COOLING TOWER CELL 8	N2018889.6 E1241188.6	N4135357 E489039	64
11	COOLING TOWER CELL 9	N2018811.0 E1241166.4	N4135333 E489032	64
12	COOLING TOWER CELL 10	N2018842.0 E1241217.4	N4135342 E489048	64
13	AUXILIARY BOILER	N2018876.0 E1240639.6	N4135350 E488871	42
14	EMERGENCY DIESEL GENERATOR	N2018937.8 E1240725.8	N4135369 E488897	11
15	FUEL GAS HEATER	N2018343.8 E1240676.0	N4135188 E488885	10
16	DIESEL FIRE PUMP	N2019138.0 E1240519.4	N4135430 E488834	10

SITE ARRANGEMENT

SCALE: 1" = 200'-0"

200 100 0 200 400 600

NOT TO BE USED FOR CONSTRUCTION

Revisions

A Project:
HDR PROJECT #211611
Dwn: J_B 11/16/13
Chkd: AWS 11/18/13
Appd: MAW

B Project:
REVISED LOCATIONS
Dwn: EDC 02/04/14
Chkd: MAW
Appd: MAW

HDR
HDR Engineering, Inc.
PROJECT: 211611

Location and Unit: GREEN RIVER	LG&E Generation Services, LOUISVILLE GAS & ELECTRIC COMPANY, a PPL company	Drawn: EDC
Scale: AS NOTED	Contract No.:	Checked: MAW
Engineering discipline: STRUCTURAL	Drawing type: PLAN	Approved: MAW
Title: GREEN RIVER 5 NGCC EMISSION POINT LOCATION PLAN		Released for: REVISED
		Alternate Drawing No.: S2501
Originator: HDR ENGINEERING, INC.	Job or Project No.: 211611	Drawing No.: 211611-CGA-S2501 Rev. B

211611-CGA-S2501

APPENDIX B: CONSTRUCTION PERMIT APPLICATION FORMS

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601
(502) 564-3999
http://www.air.ky.gov/

DEP7007AI
Administrative Information
Enter if known
AFS Plant ID# *21-177-00001*
Agency Use Only
Date Received
Log#
Permit#

PERMIT APPLICATION

The completion of this form is required under Regulations 401 KAR 52:020, 52:030, and 52:040 pursuant to KRS 224. Applications are incomplete unless accompanied by copies of all plans, specifications, and drawings requested herein. Failure to supply information required or deemed necessary by the division to enable it to act upon the application shall result in denial of the permit and ensuing administrative and legal action. Applications shall be submitted in triplicate.

1) APPLICATION INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: *Kentucky Utilities Company/Green River Generating Station*

Title: ________ **Phone:** *(502) 627-2343*

(If applicant is an individual)

Mailing Address: Company *LG&E-KU*

Street or P.O. Box: *P.O. Box 32010*

City: *Louisville* **State:** *KY* **Zip Code:** *40232*

Is the applicant (check one): ☐ Owner ☐ Operator ☐ Owner & Operator ☒ Corporation/LLC* ☐ LP**

* **If the applicant is a Corporation or a Limited Liability Corporation, submit a copy of the current Certificate of Authority from the Kentucky Secretary of State.**

** **If the applicant is a Limited Partnership, submit a copy of the current Certificate of Limited Partnership from the Kentucky Secretary of State.**

Person to contact for technical information relating to application:

Name: *Marlene Zeckner Pardee*

Title: *Senior Environmental Scientist* **Phone:** *(502) 627-2343*

2) OPERATOR INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: *Same as Applicant*

Title: ________ **Phone:** ________

Mailing Address: Company ________

Street or P.O. Box: ________

City: ________ **State:** ____ **Zip Code:** ________

DEP7007AI
(Continued)

3)	TYPE OF PERMIT APPLICATION

For new sources that currently *do not* hold *any* air quality permits in Kentucky and are required to obtain a permit prior to construction pursuant to 401 KAR 52:020, 52:030, or 52:040.

☐ Initial Operating Permit (the permit will authorize both construction and operation of the new source)

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

For existing sources that do not have a source-wide Operating Permit required by 401 KAR 52:020, 52:030, or 52:040.

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

(*Check one only)*
☐ Initial Source-wide Operating Permit ☐ Modification of Existing Facilities at Existing Plant
☐ Construction of New Facilities at Existing Plant
☐ Other (explain) ____________

For existing sources that currently have a source-wide Operating Permit.

Type of Source (*Check all that apply*): ☒ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

Current Operating Permit # V-12-018

☐ **Administrative Revision** (describe type of revision requested, e.g. name change): ____________

☐ **Permit Renewal** ☒ **Significant Revision** ☐ **Minor Revision**

☒ Addition of New Facilities ☐ Modification of Existing Facilities

For all construction and modification requiring a permit pursuant to 401 KAR 52:020, 52:030, or 52:040.

Proposed Date for Start of Construction or Modification: 2015
Proposed date for Operation Start-up: 2018

4)	SOURCE INFORMATION

Source Name: Green River Generating Station

Source Street Address: U.S. Highway 431

City: Central City **Zip Code:** 42330 **County:** Muhlenberg

Primary Standard Industrial Classification (SIC) Category: Generation & Transmission of Electricity **Primary SIC #:** 4911

Property Area (Acres or Square Feet): 407 acres **Number of Employees:** 62

Description of Area Surrounding Source (*check one*):
☐ Commercial Area ☐ Residential Area ☐ Industrial Area ☐ Industrial Park ☒ Rural Area ☐ Urban Area

Approximate Distance to Nearest Residence or Commercial Property: 0.25 miles

UTM <u>or</u> Standard Location Coordinates: (*Include topographical map showing property boundaries*)

UTM Coordinates:	Zone	16	Horizontal (km)	489108E	Vertical (km)	4135260N	
Standard Coordinates:	Latitude	37	Degrees	21	Minutes	50	Seconds
	Longitude	87	Degrees	07	Minutes	23	Seconds

DEP7007AI
(Continued)

4) SOURCE INFROMATION (CONTINUED)

Is any part of the source located on federal land? ☐ Yes ☒ No

What other environmental permits or registrations does this source currently hold in Kentucky?

KPDES Permit No. KY0002011

Certification of Registration for Hazardous Waste Management Activity – EPA ID No. KYD-980-559-884

Special Waste Permit-by-Rule (401 KAR 45:060)

What other environmental permits or registrations does this source need to obtain in Kentucky?

None

5) OTHER REQUIRED INFORMATION

Indicate the type(s) and number of forms attached as part of this application.

Number	Form	Description
6	DEP7007A	Indirect Heat Exchanger, Turbine, Internal Combustion Engine
1	DEP7007B	Manufacturing or Processing Operations
	DEP7007C	Incinerators & Waste Burners
	DEP7007F	Episode Standby Plan
	DEP7007J	Volatile Liquid Storage
	DEP7007K	Surface Coating or Printing Operations
	DEP7007L	Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer
	DEP7007M	Metal Cleaning Degreasers
1	DEP7007N	Emissions, Stacks, and Controls Information
	DEP7007P	Perchloroethylene Dry Cleaning Systems
	DEP7007R	Emission Reduction Credit
	DEP7007S	Service Stations
	DEP7007T	Metal Plating & Surface Treatment Operations
1	DEP7007V	Applicable Requirements & Compliance Activities
	DEP7007Y	Good Engineering Practice (GEP) Stack Height Determination
	DEP7007AA	Compliance Schedule for Noncomplying Emission Units
	DEP7007BB	Certified Progress Report
	DEP7007CC	Compliance Certification
1	DEP7007DD	Insignificant Activities

Check other attachments that are part of this application.

Required Data

- ☐ Map or Drawing Showing Location
  (Accessible via Google Maps based on plant address.)
- ☒ Process Flow Diagram and Description
  (See Appendix A)
- ☒ Site Plan Showing Stack Data and Locations
  (See Appendix A)
- ☒ Emission Calculation Sheets
  (See Appendix C)
- ☐ Material Safety Data Sheets (MSDS)
  (MSDS can be provided upon request if necessary.)

Supplemental Data

- ☐ Stack Test Report
- ☐ Certificate of Authority from the Secretary of State (for Corporations and Limited Liability Companies)
  (Refer to Certificate already on file.)
- ☐ Certificate of Limited Partnership from the Secretary of State (for Limited Partnerships)
- ☐ Claim of Confidentiality (See 400 KAR 1:060)
- ☐ Other (Specify) ____________

Indicate if you expect to emit, in any amount, hazardous or toxic materials or compounds or such materials into the atmosphere from any operation or process at this location.

- ☒ Pollutants regulated under 401 KAR 57:002 (NESHAP)
- ☒ Pollutants listed in 401 KAR 63:060 (HAPS)
- ☒ Pollutants listed in 40 CFR 68 Subpart F [112(r) pollutants]
- ☐ Other

Has your company filed an emergency response plan with local and/or state and federal officials outlining the measures that would be implemented to mitigate an emergency release?

☒ Yes ☐ No

Check whether your company is seeking coverage under a permit shield. If "Yes" is checked, applicable requirements must be identified on Form DEP7007V. Identify any non-applicable requirements for which you are seeking permit shield coverage on a separate attachment to the application.

☒ Yes ☐ No ☐ **A list of non-applicable requirements is attached**

DEP7007AI
(Continued)

6) OWNER INFORMATION

Note: If the applicant is the owner, write "same as applicant" on the name line.

Name: Same as Applicant

Title: ______ **Phone:** ______

Mailing Address: Company ______

Street or P.O. Box: ______

City: ______ **State:** ______ **Zip Code:** ______

List names of owners and officers of your company who have an interest in the company of 5% or more.

Name	Position (owner, partner, president, CEO, treasurer, etc.)
None	

(attach another sheet if necessary)

7) SIGNATURE BLOCK

I, the undersigned, hereby certify under penalty of law, that I am a responsible official, and that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

BY: Ralph Bowling
(Authorized Signature)

2/28/14
(Date)

Ralph Bowling
(Typed or Printed Name of Signatory)

Vice President Power Production
(Title of Signatory)

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # *EU09*
Emission Unit # *Combustion Turbine #1*

1) Type of Unit (Make, Model, Etc.): *H class turbine or equivalent*
Date Installed: *Construction projected to commence in 2015*
Cost of Unit: *$80,000,000*
Company's Identification Code: *EU09 - Combustion Turbine #1*

2a) Kind of Unit: *Gas Turbine for Electricity Generation*
2b) Rated Capacity
1. Fuel input (mmBTU/hr): *2,902*
2. Power output (hp): *N/A*
Power output (MW): *304.56*

SECTION 1. FUEL

3) Type of Primary Fuel: *C. Natural Gas*
4) Secondary Fuel (if any): *None*
5) Fuel Composition - Primary Fuel
Percent Ash (as received): *Negligible*
Percent Sulfur (as received): *0.2 gr/scf*
Corresponding Heat Content: *997.4 Btu/scf*

6) Maximum Annual Fuel Usage Rate:* *N/A*
* Only if requesting operating limit.

7) Fuel Source or supplier: *Natural gas will be supplied via pipeline*

8) Maximum Operating Schedule for Unit:*
* Only if requesting operating limit.
Hours/Day: *N/A* **Days/Week:** *N/A* **Weeks/Year:** *N/A*

9) If this unit is multipurpose, describe percent in each use category:
Space Heat: *N/A* **Process Heat:** *N/A* **Power:** *N/A*

10) Control options for turbine/IC engine: *(3) Selective Catalytic Reduction & (5) Other - Oxidation catalyst*

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS *N/A*

SECTION III.

16) Additional Stack Data
A. Are sampling ports provided? *Yes*
B. Located in accordance with 40 CFR 60? *Yes*
C. List other units vented to this stack: *None*

17) Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.
N/A

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.
Fuel Transport is via pipeline. Natural gas produces negligible particulate emissions. Thus, there will be no control equipment and no ash disposal equipment.

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DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # *EU10*
Emission Unit # *Combustion Turbine #2*

1)	**Type of Unit (Make, Model, Etc.):**	*H class turbine or equivalent*
	Date Installed:	*Construction projected to commence in 2015*
	Cost of Unit:	*$80,000,000*
	Company's Identification Code:	*EU10 - Combustion Turbine #2*
2a)	**Kind of Unit:**	*Gas Turbine for Electricity Generation*
2b)	**Rated Capacity**	
	1. Fuel input (mmBTU/hr):	*2,902*
	2. Power output (hp):	*N/A*
	Power output (MW):	*304.56*

SECTION 1. FUEL

3)	**Type of Primary Fuel:**	*C. Natural Gas*
4)	**Secondary Fuel (if any):**	*None*
5)	**Fuel Composition - Primary Fuel**	
	Percent Ash (as received):	*Negligible*
	Percent Sulfur (as received):	*0.2 gr/scf*
	Corresponding Heat Content:	*997.4 Btu/scf*
6)	**Maximum Annual Fuel Usage Rate:*** * Only if requesting operating limit.	*N/A*
7)	**Fuel Source or supplier:**	*Natural gas will be supplied via pipeline*

8) Maximum Operating Schedule for Unit:*
* Only if requesting operating limit.

Hours/Day: *N/A* **Days/Week:** *N/A* **Weeks/Year:** *N/A*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat: *N/A* **Process Heat:** *N/A* **Power:** *N/A*

10) Control options for turbine/IC engine: *(3) Selective Catalytic Reduction & (5) Other - Oxidation catalyst*

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS *N/A*

SECTION III.

16) Additional Stack Data

A.	**Are sampling ports provided?**	*Yes*
B.	**Located in accordance with 40 CFR 60?**	*Yes*
C.	**List other units vented to this stack:**	*None*

17) Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.
N/A

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.
Fuel Transport is via pipeline. Natural gas produces negligible particulate emissions. Thus, there will be no control equipment and no ash disposal equipment.

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INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # EU11
Emission Unit # Auxiliary Boiler

1)	**Type of Unit (Make, Model, Etc.):**	*Cleaver Brooks gas-fired boiler or equivalent*
	Date Installed:	*Construction projected to commence in 2015*
	Cost of Unit:	*$2,500,000*
	Company's Identification Code:	*EU11 - Auxiliary Boiler*
2a)	**Kind of Unit:**	
2b)	**Rated Capacity**	
	1. Fuel input (mmBTU/hr):	*99.9*
	2. Power output (hp):	*N/A*
	Power output (MW):	*N/A*

SECTION 1. FUEL

3)	**Type of Primary Fuel:**	*C. Natural Gas*
4)	**Secondary Fuel (if any):**	*N/A*
5)	**Fuel Composition - Primary Fuel**	
	Percent Ash (as received):	*Negligible*
	Percent Sulfur (as received):	*0.2 gr/scf*
	Corresponding Heat Content:	*997 Btu/scf*
6)	**Maximum Annual Fuel Usage Rate:***	*N/A*
	* Only if requesting operating limit.	
7)	**Fuel Source or supplier:**	*Natural gas will be supplied via pipeline*

8) **Maximum Operating Schedule for Unit:***
* Only if requesting operating limit.

Hours/Day: *N/A* **Days/Week:** *N/A* **Weeks/Year:** *N/A*

9) **If this unit is multipurpose, describe percent in each use category:**

Space Heat: *N/A* **Process Heat:** *N/A* **Power:** *N/A*

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

14) **Natural Gas-Fired Units**

Low NO_X Burners	**Yes:** ☑	**No:** ❑
Flue Gas Recirculation	**Yes:** ☑	**No:** ❑

15) **Combustion Air**

Draft **Natural** ❑ **Induced** ☑

Forced Pressure *0.6* **lbs/sq.in.**

Percent excess air (air supplied in excess of theoretical air) *15.0* **%**

SECTION III.

16) **Additional Stack Data**

A.	**Are sampling ports provided?**	*Yes*
B.	**Located in accordance with 40 CFR 60?**	*Yes*
C.	**List other units vented to this stack:**	*N/A*

17) **Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.**
N/A

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**
Fuel Transport is via pipeline. Natural gas produces negligible particulate emissions. Thus, there will be no control equipment and no ash disposal equipment.

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INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # EU13
Emission Unit # Emergency Generator

1)	**Type of Unit (Make, Model, Etc.):**	CAT Standby or equivalent
	Date Installed:	Construction projected to commence in 2015
	Cost of Unit:	$300,000
	Company's Identification Code:	EU13 - Emergency Generator
2a)	**Kind of Unit:**	Industrial Engine
2b)	**Rated Capacity**	
	1. Fuel input (mmBTU/hr):	7.60
	2. Power output (hp):	1,006
	Power output (MW):	

SECTION 1. FUEL

3)	**Type of Primary Fuel:**	H. Diesel (ULSD)
4)	**Secondary Fuel (if any):**	None
5)	**Fuel Composition - Primary Fuel**	
	Percent Ash (as received):	Negligible
	Percent Sulfur (as received):	0.0015%
	Corresponding Heat Content:	134200 Btu/gal
6)	**Maximum Annual Fuel Usage Rate:*** * Only if requesting operating limit.	N/A
7)	**Fuel Source or supplier:**	Diesel fuel purchased from local supplier

8) Maximum Operating Schedule for Unit:*
* Only if requesting operating limit.

Hours/Day: * **Days/Week:** * **Weeks/Year:** *

Unit will operate only during emergencies or for testing.

9) If this unit is multipurpose, describe percent in each use category:

Space Heat: N/A **Process Heat:** N/A **Power:** N/A

10) Control options for turbine/IC engine: N/A

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS N/A

SECTION III.

16) Additional Stack Data

A.	**Are sampling ports provided?**	N/A
B.	**Located in accordance with 40 CFR 60?**	N/A
C.	**List other units vented to this stack:**	None

17) Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.
N/A

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.
Fuel will be delivered to the facility via truck and stored in a tank located near the generator. No dust control measures are needed.

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INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # *EU14*
Emission Unit # *Fire Pump Engine*

1)	**Type of Unit (Make, Model, Etc.):**	*Cummins Fire Pump Engine or equivalent*
	Date Installed:	*Construction projected to commence in 2015*
	Cost of Unit:	*$400,000*
	Company's Identification Code:	*EU14 - Fire Pump Engine*
2a)	**Kind of Unit:**	*Industrial Engine*
2b)	**Rated Capacity**	
	1. Fuel input (mmBTU/hr):	*3.56*
	2. Power output (hp):	*542*
	Power output (MW):	

SECTION 1. FUEL

3) **Type of Primary Fuel:** *H. Diesel (ULSD)*
4) **Secondary Fuel (if any):** *None*
5) **Fuel Composition - Primary Fuel**
Percent Ash (as received): *Negligible*
Percent Sulfur (as received): *0.0015%*
Corresponding Heat Content: *134200 Btu/gal*

6) **Maximum Annual Fuel Usage Rate:*** *N/A*
* Only if requesting operating limit.

7) **Fuel Source or supplier:** *Diesel fuel purchased from local supplier*

8) **Maximum Operating Schedule for Unit:***
* Only if requesting operating limit.
Hours/Day: * **Days/Week:** * **Weeks/Year:** *
Unit will operate only during emergencies or for testing.

9) **If this unit is multipurpose, describe percent in each use category:**
Space Heat: *N/A* **Process Heat:** *N/A* **Power:** *N/A*

10) **Control options for turbine/IC engine:** *N/A*

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS *N/A*

SECTION III.

16) **Additional Stack Data**
A. **Are sampling ports provided?** *N/A*
B. **Located in accordance with 40 CFR 60?** *N/A*
C. **List other units vented to this stack:** *None*

17) **Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.**
N/A

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**
Fuel will be delivered to the facility via truck and stored in a tank located near the generator. No dust control measures are needed.

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INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # *EU15*
Emission Unit # *Fuel Gas Heater*

1)	**Type of Unit (Make, Model, Etc.):**	*GasTech fuel gas heater or equivalent*
	Date Installed:	*Construction projected to commence in 2015*
	Cost of Unit:	*$700,000*
	Company's Identification Code:	*EU15 - Fuel Gas Heater*
2a)	**Kind of Unit:**	
2b)	**Rated Capacity**	
	1. Fuel input (mmBTU/hr):	*15.00*
	2. Power output (hp):	*N/A*
	Power output (MW):	*N/A*

SECTION 1. FUEL

3)	**Type of Primary Fuel:**	*C. Natural Gas*
4)	**Secondary Fuel (if any):**	*N/A*
5)	**Fuel Composition - Primary Fuel**	
	Percent Ash (as received):	*Negligible*
	Percent Sulfur (as received):	*0.2 gr/scf*
	Corresponding Heat Content:	*997 Btu/scf*
6)	**Maximum Annual Fuel Usage Rate:*** * Only if requesting operating limit.	*N/A*
7)	**Fuel Source or supplier:**	*Natural gas will be supplied via pipeline*

8) **Maximum Operating Schedule for Unit:***
* Only if requesting operating limit.
Hours/Day: *N/A* **Days/Week:** *N/A* **Weeks/Year:** *N/A*

9) **If this unit is multipurpose, describe percent in each use category:**
Space Heat: *N/A* **Process Heat:** *N/A* **Power:** *N/A*

SECTION II. COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

14) **Natural Gas-Fired Units**

Low NO_X Burners	Yes: ☑	No: ☐
Flue Gas Recirculation	Yes: ☐	No: ☑

15) **Combustion Air**

Draft — Natural ☐ Induced ☑
Forced Pressure *0.5* **lbs/sq.in.**
Percent excess air (air supplied in excess of theoretical air) *15.0* **%**

SECTION III.

16) **Additional Stack Data**
- **A. Are sampling ports provided?** *Yes*
- **B. Located in accordance with 40 CFR 60?** *Yes*
- **C. List other units vented to this stack:** *None*

17) **Attach manufacturer specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners, and combustion chamber dimensions.**
N/A

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**
Fuel Transport is via pipeline. Natural gas produces negligible particulate emissions. Thus, there will be no control equipment and no ash disposal equipment.

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DEP7007B

MANUFACTURING OR PROCESSING OPERATIONS

(*Please read instructions before completing this form*)

Emission Unit # (1)	Process Description (2)	Continuous or Batch (3)	Maximum Operating Schedule (Hours/Day, Days/Week, Weeks/Year) (4)	Process Equipment (Make, Model, Etc.) (5)	Date Installed (6)
EU12	Cooling Tower	N/A	24 hr/day; 7 day/wk; 52 wk/yr	Counter-flow mechanical draft	Construction projected to commence in 2015

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DEP7007B
MANUFACTURING OR PROCESSING OPERATIONS

(*Please read instructions before completing this form*)

Emission Unit # (1)	Process Description	List Raw Material(s) Used (7)	Maximum Quantity Input Of Each Raw Material (Specify Units/Hour) (8) See Item 18	Type of Products (9) See Item 18	Quantity Output (Specify Units)	
					Maximum Hourly Rated Capacity (Specify Units) (10a)	Maximum Annual (Specify Units)
EU12	Cooling Tower	Heated water	13.20 MMgal/hr	Cooled water	13.20 MMgal/hr	N/A

***(10a) Rated Capacity of Equipment** **(10b) Should be entered only if applicant requests operating restrictions through federally enforceable limitations**

DEP7007B (Continued)

IMPORTANT: Form DEP7007N, Emission, Stacks, and Controls Information must be completed for each emission unit listed below.

Emission Unit # (1)	Process Description	Fuel Type for Process Heat (11)	Rated Burner Capacity (MMBTU/Hour) (12)	Fuel Composition		Fuel Usage Rates		Note: If combustion products are emitted along with process emissions, indicate so by writing "combined." (15)
				% Sulfur (13a)	% Ash (13b)	Maximum Hourly (14a)	Maximum Annual (14b)	
EU12	Cooling Tower	N/A	N/A	N/A	N/A	N/A	N/A	N/A

16) Make a complete list of all wastes generated by each process (e.g., wastewater, scrap, rejects, cleanup waste, etc.). List the hourly (or daily) and annual quantities of each waste and the method of final disposal. (Use a separate sheet of paper, if necessary)

N/A

17) IMPORTANT: Submit a process flow diagram. Label all materials, equipment and emission point numbers.

See Appendix A

18) Material Safety Data Sheets with complete chemical compositions are required for each process.

MSDS can be provided upon request. Information on MSDS are not relevant to regulatory applicability determinations or for emission calculations for the covered processes.

***(14b) Should be entered only if applicant requests operating restrictions through federally enforceable permit conditions.**

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DEP7007N

Emissions, Stacks, and Controls Information

Applicant Name: ***Kentucky Utilities Company/Green River*** Log #_______

SECTION I. Emissions Unit and Emission Point Information

KyEIS Source ID	KyEIS Process ID	Emission Source Description	Date Construct	HAP present?	SCC Code	SCC Units	Fuel Ash Content	Fuel Sulfur Content	Fuel Heat Content Ratio[1,2]	Applicable Regulations	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
EU09	1	Combustion Turbine #1 - Normal Operation	Projected 2015	Y	20100201	MMcf	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	2.91	8,760	N/A	N/A	N/A
EU09	2	Combustion Turbine #1 - Cold Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	0.00	0	N/A	N/A	N/A
EU09	3	Combustion Turbine #1 - Warm Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	1.33	39	N/A	N/A	N/A
EU09	4	Combustion Turbine #1 - Hot Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	2.00	104	N/A	N/A	N/A
EU09	5	Combustion Turbine #1 - Shutdown	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	5.45	48	N/A	N/A	N/A

SECTION I. Emissions Unit and Emission Point Information

KyEIS Source ID	KyEIS Process ID	Emission Source Description	Date Construct	HAP present?	SCC Code	SCC Units	Fuel Ash Content	Fuel Sulfur Content	Fuel Heat Content Ratio[1,2]	Applicable Regulations	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
EU10	1	Combustion Turbine #2 - Normal Operation	Projected 2015	Y	20100201	MMcf	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	2.91	8,760	N/A	N/A	N/A
EU10	2	Combustion Turbine #2 - Cold Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	0.00	0	N/A	N/A	N/A
EU10	3	Combustion Turbine #2 - Warm Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	1.33	39	N/A	N/A	N/A
EU10	4	Combustion Turbine #2 - Hot Startup	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	2.00	104	N/A	N/A	N/A
EU10	5	Combustion Turbine #2 - Shutdown	Projected 2015	Y	39999999	event	Neg.	0.2 grains/scf	0.98	NSPS KKKK; 40 CFR 64; 40 CFR 72-78; 40 CFR 96; 401 KAR 51:017	5.45	48	N/A	N/A	N/A
EU11	1	Auxiliary Boiler	Projected 2015	Y	10200602	MMcf	Neg.	0.2 grains/scf	0.98	NSPS Dc; 401 KAR 59:015	0.10	8,760	N/A	N/A	N/A
EU12	1	Cooling Tower	Projected 2015	N	38500101	MMgal	N/A	N/A	N/A	None	13.20	8,760	N/A	N/A	N/A
EU13	1	Emergency Generator	Projected 2015	Y	20200102	Mgal	Neg.	< 0.0015%	0.99	NSPS IIII; NESHAP ZZZZ	0.06	500	N/A	N/A	N/A
EU14	1	Fire Pump Engine	Projected 2015	Y	20100102	Mgal	Neg.	< 0.0015%	0.99	NSPS IIII; NESHAP ZZZZ	0.03	500	N/A	N/A	N/A
EU15	1	Fuel Gas Heater	Projected 2015	Y	10200602	MMcf	Neg.	0.2 grains/scf	0.98	NSPS Dc; 401 KAR 59:015	0.02	8,760	N/A	N/A	N/A

[1] Based on default AP-42 Section 1.4 natural gas fuel heat content of 1,020 Btu/scf.

[2] Based on default AP-42 Table 3.3-1 diesel heating value of 19,300 Btu/lb.

DEP7007N
(continued)

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Pollutant	CAS#	Emission Factors: Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
EU09		Combustion Turbine #1, H Class														
	1	Normal Operation														
		CO	630-08-0	22.1 lb/MMcf	Manufacturer emissions data	C01	Oxidation Catalyst	80%	2.9	64.2	12.8	N/A	25,486	281.4	56.3	N/A
		NO_X (as NO_2)	10102-44-0	93.6 lb/MMcf	Manufacturer emissions data	C03	SCR	42%	2.9	272.3	158.3	N/A	25,486	1,193	693.3	N/A
		PM Filterable	N/A	2.5 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	7.3	N/A	N/A	25,486	31.8	N/A	N/A
		Total PM/PM_{10}/ $PM_{2.5}$	N/A	5.0 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	14.5	N/A	N/A	25,486	63.5	N/A	N/A
		SO_2	7446-09-5	57.1 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	166.2	N/A	N/A	25,486	728.2	N/A	N/A
		VOC	N/A	1.3 lb/MMcf	Manufacturer emissions data	C01	Oxidation Catalyst	50%	2.9	3.8	1.9	N/A	25,486	16.6	8.3	N/A
		SAM	7664-93-9	2.4 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	7.1	N/A	N/A	25,486	30.9	N/A	N/A
		CO_2	124-38-9	117,372 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	341,477	N/A	N/A	25,486	1,495,669	N/A	N/A
		N_2O	10024-97-2	0.2 lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.9	0.6	N/A	N/A	25,486	2.8	N/A	N/A
		CH_4	74-82-8	2.2 lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.9	6.4	N/A	N/A	25,486	28.0	N/A	N/A
		Acetaldehyde	75-07-0	4.3E-02 lb/MMcf	EPA Turbine MACT database	C01	Oxidation Catalyst	50%	2.9	0.1	0.1	N/A	25,486	0.5	0.3	N/A
		Formaldehyde	50-00-0	0.2 lb/MMcf	EPA Turbine MACT database	C01	Oxidation Catalyst	50%	2.9	0.6	0.3	N/A	25,486	2.7	1.4	N/A
		Propylene Oxide	75-56-9	2.9E-02 lb/MMcf	EPA Turbine MACT database	C01	Oxidation Catalyst	50%	2.9	0.1	4.1E-02	N/A	25,486	0.4	0.2	N/A
		Toluene	108-88-3	0.1 lb/MMcf	EPA Turbine MACT database	C01	Oxidation Catalyst	50%	2.9	0.2	0.1	N/A	25,486	0.9	0.4	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Xylene (total)	1330-20-7	0.1 lb/MMcf	EPA Turbine MACT database	C01	Oxidation Catalyst	50%	2.9	0.2	0.1	N/A	25,486	0.8	0.4	N/A
	2	Cold Startup														
		CO	630-08-0	631.8 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	50%	0	0	0	N/A	0	0	0	N/A
		NO_X (as NO_2)	10102-44-0	203.5 lb/event	Manufacturer emissions data	C03	SCR	0	0	0	0	N/A	0	0	0	N/A
		PM Filterable	N/A	7.9 lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		Total $PM/PM_{10}/PM_{2.5}$	N/A	15.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		SO_2	7446-09-5	180.1 lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		VOC	N/A	114.1 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		SAM	7664-93-9	7.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		CO_2	124-38-9	187,283 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		N_2O	10024-97-2	0.4 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		CH_4	74-82-8	3.5 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		Acetaldehyde	75-07-0	0.1 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Formaldehyde	50-00-0	0.8 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Propylene Oxide	75-56-9	0.1 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Toluene	108-88-3	0.2 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Xylene (total)	1330-20-7	0.2 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
	3	Warm Startup														

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		CO	630-08-0	1,250 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	50%	1.3	1,667	833.6	N/A	52.0	32.5	16.3	N/A
		NO_X (as NO_2)	10102-44-0	148.9 lb/event	Manufacturer emissions data	C03	SCR	0	1.3	198.5	198.5	N/A	52.0	3.9	3.9	N/A
		PM Filterable	N/A	5.4 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	7.3	N/A	N/A	52.0	0.1	N/A	N/A
		Total PM/PM_{10}/ $PM_{2.5}$	N/A	10.9 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	14.5	N/A	N/A	52.0	0.3	N/A	N/A
		SO_2	7446-09-5	124.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	166.2	N/A	N/A	52.0	3.2	N/A	N/A
		VOC	N/A	141.9 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	20%	1.3	189.2	151.3	N/A	52.0	3.7	3.0	N/A
		SAM	7664-93-9	5.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	7.1	N/A	N/A	52.0	0.1	N/A	N/A
		CO_2	124-38-9	121,876 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	1.3	162,502	N/A	N/A	52.0	3,169	N/A	N/A
		N_2O	10024-97-2	0.2 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.3	0.3	N/A	N/A	52.0	5.9E-03	N/A	N/A
		CH_4	74-82-8	2.3 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.3	3.0	N/A	N/A	52.0	0.1	N/A	N/A
		Acetaldehyde	75-07-0	6.5 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	1.3	8.7	6.9	N/A	52.0	0.2	0.1	N/A
		Formaldehyde	50-00-0	36.6 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	1.3	48.8	39.0	N/A	52.0	1.0	0.8	N/A
		Propylene Oxide	75-56-9	4.3 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	1.3	5.8	4.6	N/A	52.0	0.1	0.1	N/A
		Toluene	108-88-3	10.3 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	1.3	13.7	11.0	N/A	52.0	0.3	0.2	N/A
		Xylene (total)	1330-20-7	9.8 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	1.3	13.1	10.5	N/A	52.0	0.3	0.2	N/A
	4	Hot Startup														
		CO	630-08-0	1,240 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	50%	2.0	2,481	1,240	N/A	208.0	129.0	64.5	N/A
		NO_X (as NO_2)	10102-44-0	107.9 lb/event	Manufacturer emissions data	C03	SCR	0	2.0	215.7	215.7	N/A	208.0	11.2	11.2	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		PM Filterable	N/A	3.6 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	7.3	N/A	N/A	208.0	0.4	N/A	N/A
		Total PM/PM_{10}/ $PM_{2.5}$	N/A	7.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	14.5	N/A	N/A	208.0	0.8	N/A	N/A
		SO_2	7446-09-5	83.1 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	166.2	N/A	N/A	208.0	8.6	N/A	N/A
		VOC	N/A	141.3 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	20%	2.0	282.6	226.1	N/A	208.0	14.7	11.8	N/A
		SAM	7664-93-9	3.5 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	7.1	N/A	N/A	208.0	0.4	N/A	N/A
		CO_2	124-38-9	72,822 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	2.0	145,644	N/A	N/A	208.0	7,573	N/A	N/A
		N_2O	10024-97-2	0.1 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.0	0.3	N/A	N/A	208.0	1.4E-02	N/A	N/A
		CH_4	74-82-8	1.4 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.0	2.7	N/A	N/A	208.0	0.1	N/A	N/A
		Acetaldehyde	75-07-0	4.3 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	2.0	8.7	6.9	N/A	208.0	0.5	0.4	N/A
		Formaldehyde	50-00-0	24.4 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	2.0	48.8	39.0	N/A	208.0	2.5	2.0	N/A
		Propylene Oxide	75-56-9	2.9 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	2.0	5.8	4.6	N/A	208.0	0.3	0.2	N/A
		Toluene	108-88-3	6.9 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	2.0	13.7	11.0	N/A	208.0	0.7	0.6	N/A
		Xylene (total)	1330-20-7	6.6 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	2.0	13.1	10.5	N/A	208.0	0.7	0.5	N/A
	5	Shutdown														
		CO	630-08-0	846.0 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	50%	5.5	4,615	2,307	N/A	260.0	110.0	55.0	N/A
		NO_X (as NO_2)	10102-44-0	51.0 lb/event	Manufacturer emissions data	C03	SCR	0	5.5	278.2	278.2	N/A	260.0	6.6	6.6	N/A
		PM Filterable	N/A	1.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	7.3	N/A	N/A	260.0	0.2	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
		Total PM/PM_{10}/ $PM_{2.5}$	N/A	2.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	14.5	N/A	N/A	260.0	0.3	N/A	N/A
		SO_2	7446-09-5	30.5 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	166.2	N/A	N/A	260.0	4.0	N/A	N/A
		VOC	N/A	97.0 lb/event	Manufacturer emissions data	C01	Oxidation Catalyst	20%	5.5	529.1	423.3	N/A	260.0	12.6	10.1	N/A
		SAM	7664-93-9	1.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	7.1	N/A	N/A	260.0	0.2	N/A	N/A
		CO_2	124-38-9	24,644 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	5.5	134,420	N/A	N/A	260.0	3,204	N/A	N/A
		N_2O	10024-97-2	4.8E-02 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	5.5	0.3	N/A	N/A	260.0	6.2E-03	N/A	N/A
		CH_4	74-82-8	0.5 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	5.5	2.6	N/A	N/A	260.0	0.1	N/A	N/A
		Acetaldehyde	75-07-0	1.6 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	5.5	8.7	6.9	N/A	260.0	0.2	0.2	N/A
		Formaldehyde	50-00-0	8.9 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	5.5	48.8	39.0	N/A	260.0	1.2	0.9	N/A
		Propylene Oxide	75-56-9	1.1 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	5.5	5.8	4.6	N/A	260.0	0.1	0.1	N/A
		Toluene	108-88-3	2.5 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	5.5	13.7	11.0	N/A	260.0	0.3	0.3	N/A
		Xylene (total)	1330-20-7	2.4 lb/event	EPA Turbine MACT database	C01	Oxidation Catalyst	20%	5.5	13.1	10.5	N/A	260.0	0.3	0.3	N/A
EU10		Combustion Turbine #2, H Class														
	1	Normal Operation														
		CO	630-08-0	22.1 lb/MMcf	Manufacturer emissions data	C02	Oxidation Catalyst	80%	2.9	64.2	12.8	N/A	25,486	281.4	56.3	N/A
		NOX (as NO2)	10102-44-0	93.6 lb/MMcf	Manufacturer emissions data	C04	SCR	42%	2.9	272.3	158.3	N/A	25,486	1,193	693.3	N/A
		PM Filterable	N/A	2.5 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	7.3	N/A	N/A	25,486	31.8	N/A	N/A
		Total PM/PM10/ I	N/A	5.0 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	14.5	N/A	N/A	25,486	63.5	N/A	N/A
		SO2	7446-09-5	57.1 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	166.2	N/A	N/A	25,486	728.2	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
		VOC	N/A	1.3	lb/MMcf	Manufacturer emissions data	C02	Oxidation Catalyst	50%	2.9	3.8	1.9	N/A	25,486	16.6	8.3	N/A
		SAM	7664-93-9	2.4	lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	7.1	N/A	N/A	25,486	30.9	N/A	N/A
		CO2	124-38-9	117,372	lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	2.9	341,477	N/A	N/A	25,486	1,495,669	N/A	N/A
		N2O	10024-97-2	0.2	lb/MMcf	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	2.9	0.6	N/A	N/A	25,486	2.8	N/A	N/A
		CH4	74-82-8	2.2	lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.9	6.4	N/A	N/A	25,486	28.0	N/A	N/A
		Acetaldehyde	75-07-0	4.3E-02	lb/MMcf	40 CFR 98, Subpart C, Table C-2	C02	Oxidation Catalyst	50%	2.9	0.1	0.1	N/A	25,486	0.5	0.3	N/A
		Formaldehyde	50-00-0	0.2	lb/MMcf	EPA Turbine MACT database	C02	Oxidation Catalyst	50%	2.9	0.6	0.3	N/A	25,486	2.7	1.4	N/A
		Propylene Oxide	75-56-9	2.9E-02	lb/MMcf	EPA Turbine MACT database	C02	Oxidation Catalyst	50%	2.9	0.1	4.1E-02	N/A	25,486	0.4	0.2	N/A
		Toluene	108-88-3	0.1	lb/MMcf	EPA Turbine MACT database	C02	Oxidation Catalyst	50%	2.9	0.2	0.1	N/A	25,486	0.9	0.4	N/A
		Xylene (total)	1330-20-7	0.1	lb/MMcf	EPA Turbine MACT database	C02	Oxidation Catalyst	50%	2.9	0.2	0.1	N/A	25,486	0.8	0.4	N/A
	2	Cold Startup															
		CO	630-08-0	631.8	lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	50%	0	0	0	N/A	0	0	0	N/A
		NOX (as NO2)	10102-44-0	203.5	lb/event	Manufacturer emissions data	C04	SCR	0	0	0	0	N/A	0	0	0	N/A
		PM Filterable	N/A	7.9	lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		Total PM/PM10/ I	N/A	15.7	lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		SO2	7446-09-5	180.1	lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		VOC	N/A	114.1	lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		SAM	7664-93-9	7.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		CO2	124-38-9	187,283 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		N2O	10024-97-2	0.4 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		CH4	74-82-8	3.5 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A
		Acetaldehyde	75-07-0	0.1 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Formaldehyde	50-00-0	0.8 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Propylene Oxide	75-56-9	0.1 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Toluene	108-88-3	0.2 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
		Xylene (total)	1330-20-7	0.2 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	0	0	0	N/A	0	0	0	N/A
	3	Warm Startup														
		CO	630-08-0	1,250 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	50%	1.3	1,667	833.6	N/A	52.0	32.5	16.3	N/A
		NOX (as NO2)	10102-44-0	148.9 lb/event	Manufacturer emissions data	C04	SCR	0	1.3	198.5	198.5	N/A	52.0	3.9	3.9	N/A
		PM Filterable	N/A	5.4 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	7.3	N/A	N/A	52.0	0.1	N/A	N/A
		Total PM/PM10/ I	N/A	10.9 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	14.5	N/A	N/A	52.0	0.3	N/A	N/A
		SO2	7446-09-5	124.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	166.2	N/A	N/A	52.0	3.2	N/A	N/A
		VOC	N/A	141.9 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	20%	1.3	189.2	151.3	N/A	52.0	3.7	3.0	N/A
		SAM	7664-93-9	5.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	1.3	7.1	N/A	N/A	52.0	0.1	N/A	N/A
		CO2	124-38-9	121,876 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	1.3	162,502	N/A	N/A	52.0	3,169	N/A	N/A
		N2O	10024-97-2	0.2 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.3	0.3	N/A	N/A	52.0	5.9E-03	N/A	N/A
		CH4	74-82-8	2.3 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.3	3.0	N/A	N/A	52.0	0.1	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
		Acetaldehyde	75-07-0	6.5 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	1.3	8.7	6.9	N/A	52.0	0.2	0.1	N/A
		Formaldehyde	50-00-0	36.6 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	1.3	48.8	39.0	N/A	52.0	1.0	0.8	N/A
		Propylene Oxide	75-56-9	4.3 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	1.3	5.8	4.6	N/A	52.0	0.1	0.1	N/A
		Toluene	108-88-3	10.3 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	1.3	13.7	11.0	N/A	52.0	0.3	0.2	N/A
		Xylene (total)	1330-20-7	9.8 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	1.3	13.1	10.5	N/A	52.0	0.3	0.2	N/A
	4	Hot Startup														
		CO	630-08-0	1,240 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	50%	2.0	2,481	1,240	N/A	208.0	129.0	64.5	N/A
		NOX (as NO2)	10102-44-0	107.9 lb/event	Manufacturer emissions data	C04	SCR	0	2.0	215.7	215.7	N/A	208.0	11.2	11.2	N/A
		PM Filterable	N/A	3.6 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	7.3	N/A	N/A	208.0	0.4	N/A	N/A
		Total PM/PM10/ I	N/A	7.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	14.5	N/A	N/A	208.0	0.8	N/A	N/A
		SO2	7446-09-5	83.1 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	166.2	N/A	N/A	208.0	8.6	N/A	N/A
		VOC	N/A	141.3 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	20%	2.0	282.6	226.1	N/A	208.0	14.7	11.8	N/A
		SAM	7664-93-9	3.5 lb/event	Manufacturer emissions data	N/A	N/A	N/A	2.0	7.1	N/A	N/A	208.0	0.4	N/A	N/A
		CO2	124-38-9	72,822 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	2.0	145,644	N/A	N/A	208.0	7,573	N/A	N/A
		N2O	10024-97-2	0.1 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.0	0.3	N/A	N/A	208.0	1.4E-02	N/A	N/A
		CH4	74-82-8	1.4 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.0	2.7	N/A	N/A	208.0	0.1	N/A	N/A
		Acetaldehyde	75-07-0	4.3 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	2.0	8.7	6.9	N/A	208.0	0.5	0.4	N/A
		Formaldehyde	50-00-0	24.4 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	2.0	48.8	39.0	N/A	208.0	2.5	2.0	N/A
		Propylene Oxide	75-56-9	2.9 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	2.0	5.8	4.6	N/A	208.0	0.3	0.2	N/A
		Toluene	108-88-3	6.9 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	2.0	13.7	11.0	N/A	208.0	0.7	0.6	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Xylene (total)	1330-20-7	6.6 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	2.0	13.1	10.5	N/A	208.0	0.7	0.5	N/A
	5	Shutdown														
		CO	630-08-0	846.0 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	50%	5.5	4,615	2,307	N/A	260.0	110.0	55.0	N/A
		NOX (as NO2)	10102-44-0	51.0 lb/event	Manufacturer emissions data	C04	SCR	0	5.5	278.2	278.2	N/A	260.0	6.6	6.6	N/A
		PM Filterable	N/A	1.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	7.3	N/A	N/A	260.0	0.2	N/A	N/A
		Total PM/PM10/ I	N/A	2.7 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	14.5	N/A	N/A	260.0	0.3	N/A	N/A
		SO2	7446-09-5	30.5 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	166.2	N/A	N/A	260.0	4.0	N/A	N/A
		VOC	N/A	97.0 lb/event	Manufacturer emissions data	C02	Oxidation Catalyst	20%	5.5	529.1	423.3	N/A	260.0	12.6	10.1	N/A
		SAM	7664-93-9	1.3 lb/event	Manufacturer emissions data	N/A	N/A	N/A	5.5	7.1	N/A	N/A	260.0	0.2	N/A	N/A
		CO2	124-38-9	24,644 lb/event	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	5.5	134,420	N/A	N/A	260.0	3,204	N/A	N/A
		N2O	10024-97-2	4.8E-02 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	5.5	0.3	N/A	N/A	260.0	6.2E-03	N/A	N/A
		CH4	74-82-8	0.5 lb/event	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	5.5	2.6	N/A	N/A	260.0	0.1	N/A	N/A
		Acetaldehyde	75-07-0	1.6 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	5.5	8.7	6.9	N/A	260.0	0.2	0.2	N/A
		Formaldehyde	50-00-0	8.9 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	5.5	48.8	39.0	N/A	260.0	1.2	0.9	N/A
		Propylene Oxide	75-56-9	1.1 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	5.5	5.8	4.6	N/A	260.0	0.1	0.1	N/A
		Toluene	108-88-3	2.5 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	5.5	13.7	11.0	N/A	260.0	0.3	0.3	N/A
		Xylene (total)	1330-20-7	2.4 lb/event	EPA Turbine MACT database	C02	Oxidation Catalyst	20%	5.5	13.1	10.5	N/A	260.0	0.3	0.3	N/A
EU11		Auxiliary Boiler														
	1	Natural Gas Combustion														
		CO	630-08-0	74.8 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	0.1	7.5	N/A	N/A	877.4	32.8	N/A	N/A
		NO_X (as NO_2)	10102-44-0	35.9 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	0.1	3.6	N/A	N/A	877.4	15.8	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors					Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		PM	N/A	7.0	lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	0.1	0.7	N/A	N/A	877.4	3.1	N/A	N/A
		PM_{10}	N/A	7.0	lb/MMcf	Assumed equal to PM	N/A	N/A	N/A	0.1	0.7	N/A	N/A	877.4	3.1	N/A	N/A
		$PM_{2.5}$	N/A	7.0	lb/MMcf	Assumed equal to PM	N/A	N/A	N/A	0.1	0.7	N/A	N/A	877.4	3.1	N/A	N/A
		SO_2	7446-09-5	3.0	lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	0.1	0.3	N/A	N/A	877.4	1.3	N/A	N/A
		VOC	N/A	5.5	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	0.6	N/A	N/A	877.4	2.4	N/A	N/A
		CO_2	124-38-9	116,584	lb/MMcf	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	0.1	11,677	N/A	N/A	877.4	51,146	N/A	N/A
		N_2O	10024-97-2	0.2	lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0.1	2.2E-02	N/A	N/A	877.4	0.1	N/A	N/A
		CH_4	74-82-8	2.2	lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0.1	0.2	N/A	N/A	877.4	1.0	N/A	N/A
		Benzene	71-43-2	2.1E-03	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	2.1E-04	N/A	N/A	877.4	9.2E-04	N/A	N/A
		Formaldehyde	50-00-0	0.1	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	7.5E-03	N/A	N/A	877.4	3.3E-02	N/A	N/A
		Hexane	110-54-3	1.8	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	0.2	N/A	N/A	877.4	0.8	N/A	N/A
		Nickel	7440-02-0	2.1E-03	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	2.1E-04	N/A	N/A	877.4	9.2E-04	N/A	N/A
		Toluene	108-88-3	3.4E-03	lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	0.1	3.4E-04	N/A	N/A	877.4	1.5E-03	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
EU12		Cooling Tower														
	1	Fugitive Emissions														
		PM	N/A	3.9E-02 lb/MMgal	Design Information	N/A	N/A	N/A	13.2	0.5	N/A	N/A	115,632	2.3	N/A	N/A
		PM_{10}	N/A	2.8E-02 lb/MMgal	Design Information	N/A	N/A	N/A	13.2	0.4	N/A	N/A	115,632	1.6	N/A	N/A
		$PM_{2.5}$	N/A	8.7E-05 lb/MMgal	Design Information	N/A	N/A	N/A	13.2	1.1E-03	N/A	N/A	115,632	5.0E-03	N/A	N/A
EU13		Emergency Generator														
	1	Diesel Fuel Combustion (ULSD)														
		CO	630-08-0	9.8 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	0.1	0.6	N/A	N/A	28.3	0.1	N/A	N/A
		NO_X (as NO_2)	10102-44-0	205.6 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	0.1	11.6	N/A	N/A	28.3	2.9	N/A	N/A
		PM	N/A	0.8 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	0.1	4.7E-02	N/A	N/A	28.3	1.2E-02	N/A	N/A
		PM_{10}	N/A	0.8 lb/Mgal	Assumed equal to PM	N/A	N/A	N/A	0.1	4.7E-02	N/A	N/A	28.3	1.2E-02	N/A	N/A
		$PM_{2.5}$	N/A	0.8 lb/Mgal	Assumed equal to PM	N/A	N/A	N/A	0.1	4.7E-02	N/A	N/A	28.3	1.2E-02	N/A	N/A
		SO_2	7446-09-5	0.2 lb/Mgal	Maximum fuel sulfur content	N/A	N/A	N/A	0.1	1.2E-02	N/A	N/A	28.3	3.0E-03	N/A	N/A
		VOC (NMHC)	N/A	1.2 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	0.1	0.1	N/A	N/A	28.3	1.7E-02	N/A	N/A
		CO_2	124-38-9	21,883 lb/Mgal	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	0.1	1,239	N/A	N/A	28.3	309.8	N/A	N/A
		N_2O	10024-97-2	0.2 lb/Mgal	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0.1	1.0E-02	N/A	N/A	28.3	2.5E-03	N/A	N/A
		CH_4	74-82-8	0.9 lb/Mgal	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	0.1	0.1	N/A	N/A	28.3	1.3E-02	N/A	N/A
		Benzene	71-43-2	0.1 lb/Mgal	AP-42 Section 3.4	N/A	N/A	N/A	0.1	5.9E-03	N/A	N/A	28.3	1.5E-03	N/A	N/A
		Formaldehyde	50-00-0	1.1E-02 lb/Mgal	AP-42 Section 3.4	N/A	N/A	N/A	0.1	6.0E-04	N/A	N/A	28.3	1.5E-04	N/A	N/A
		Naphthalene	91-20-3	1.7E-02 lb/Mgal	AP-42 Section 3.4	N/A	N/A	N/A	0.1	9.9E-04	N/A	N/A	28.3	2.5E-04	N/A	N/A
		Toluene	108-88-3	3.8E-02 lb/Mgal	AP-42 Section 3.4	N/A	N/A	N/A	0.1	2.1E-03	N/A	N/A	28.3	5.3E-04	N/A	N/A
		Xylene (Total)	1330-20-7	2.6E-02 lb/Mgal	AP-42 Section 3.4	N/A	N/A	N/A	0.1	1.5E-03	N/A	N/A	28.3	3.7E-04	N/A	N/A
EU14		Fire Pump Engine														
	1	Diesel Fuel Combustion (ULSD)														

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		CO	630-08-0	30.3 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	2.7E-02	0.8	N/A	N/A	13.3	0.2	N/A	N/A
		NO_X (as NO_2)	10102-44-0	115.7 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	2.7E-02	3.1	N/A	N/A	13.3	0.8	N/A	N/A
		PM	N/A	3.5 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	2.7E-02	0.1	N/A	N/A	13.3	2.3E-02	N/A	N/A
		PM_{10}	N/A	3.5 lb/Mgal	Assumed equal to PM	N/A	N/A	N/A	2.7E-02	0.1	N/A	N/A	13.3	2.3E-02	N/A	N/A
		$PM_{2.5}$	N/A	3.5 lb/Mgal	Assumed equal to PM	N/A	N/A	N/A	2.7E-02	0.1	N/A	N/A	13.3	2.3E-02	N/A	N/A
		SO_2	7446-09-5	0.2 lb/Mgal	Maximum fuel sulfur content	N/A	N/A	N/A	2.7E-02	5.6E-03	N/A	N/A	13.3	1.4E-03	N/A	N/A
		VOC (NMHC)	N/A	3.9 lb/Mgal	Manufacturer emissions data	N/A	N/A	N/A	2.7E-02	0.1	N/A	N/A	13.3	2.6E-02	N/A	N/A
		CO_2	124-38-9	21,883 lb/Mgal	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	2.7E-02	579.9	N/A	N/A	13.3	145.0	N/A	N/A
		N_2O	10024-97-2	0.2 lb/Mgal	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.7E-02	4.7E-03	N/A	N/A	13.3	1.2E-03	N/A	N/A
		CH_4	74-82-8	0.9 lb/Mgal	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	2.7E-02	2.4E-02	N/A	N/A	13.3	5.9E-03	N/A	N/A
		Acetaldehyde	75-07-0	0.1 lb/Mgal	AP-42 Section 3.3	N/A	N/A	N/A	2.7E-02	2.7E-03	N/A	N/A	13.3	6.8E-04	N/A	N/A
		Benzene	71-43-2	0.1 lb/Mgal	AP-42 Section 3.3	N/A	N/A	N/A	2.7E-02	3.3E-03	N/A	N/A	13.3	8.3E-04	N/A	N/A
		Formaldehyde	50-00-0	0.2 lb/Mgal	AP-42 Section 3.3	N/A	N/A	N/A	2.7E-02	4.2E-03	N/A	N/A	13.3	1.0E-03	N/A	N/A
		Toluene	108-88-3	0.1 lb/Mgal	AP-42 Section 3.3	N/A	N/A	N/A	2.7E-02	1.5E-03	N/A	N/A	13.3	3.6E-04	N/A	N/A
		Xylene (Total)	1330-20-7	3.8E-02 lb/Mgal	AP-42 Section 3.3	N/A	N/A	N/A	2.7E-02	1.0E-03	N/A	N/A	13.3	2.5E-04	N/A	N/A

KyEIS Source ID	Process ID	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Rate (SCC Units/hr)	Hourly Uncontrolled Unlimited Potential	Hourly Controlled Limited Potential	Hourly Allowable	Potential Annual Rate (SCC Units/yr)*	Annual Uncontrolled Unlimited Potential	Annual Controlled Limited Potential	Annual Allowable
EU15		Fuel Gas Heater														
	1	Natural Gas Combustion														
		CO	630-08-0	84.0 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	1.3	N/A	N/A	131.7	5.5	N/A	N/A
		NO_X (as NO_2)	10102-44-0	59.8 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	1.5E-02	0.9	N/A	N/A	131.7	3.9	N/A	N/A
		PM	N/A	7.0 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	1.5E-02	0.1	N/A	N/A	131.7	0.5	N/A	N/A
		PM_{10}	N/A	7.0 lb/MMcf	Assumed equal to PM	N/A	N/A	N/A	1.5E-02	0.1	N/A	N/A	131.7	0.5	N/A	N/A
		$PM_{2.5}$	N/A	7.0 lb/MMcf	Assumed equal to PM	N/A	N/A	N/A	1.5E-02	0.1	N/A	N/A	131.7	0.5	N/A	N/A
		SO_2	7446-09-5	3.0 lb/MMcf	Manufacturer emissions data	N/A	N/A	N/A	1.5E-02	4.5E-02	N/A	N/A	131.7	0.2	N/A	N/A
		VOC (NMHC)	N/A	5.5 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	0.1	N/A	N/A	131.7	0.4	N/A	N/A

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS Source ID	Process ID	Emission Factors				Control Equipment			Hourly Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Potential Annual Rate (SCC Units/yr)*	Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		CO_2	124-38-9	116,584 lb/MMcf	40 CFR 98, Subpart C, Table C-1	N/A	N/A	N/A	1.5E-02	1,753	N/A	N/A	131.7	7,680	N/A	N/A
		N_2O	10024-97-2	0.2 lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.5E-02	3.3E-03	N/A	N/A	131.7	1.4E-02	N/A	N/A
		CH_4	74-82-8	2.2 lb/MMcf	40 CFR 98, Subpart C, Table C-2	N/A	N/A	N/A	1.5E-02	3.3E-02	N/A	N/A	131.7	0.1	N/A	N/A
		Benzene	71-43-2	2.1E-03 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	3.2E-05	N/A	N/A	131.7	1.4E-04	N/A	N/A
		Formaldehyde	50-00-0	0.1 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	1.1E-03	N/A	N/A	131.7	4.9E-03	N/A	N/A
		Hexane	110-54-3	1.8 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	2.7E-02	N/A	N/A	131.7	0.1	N/A	N/A
		Nickel	7440-02-0	2.1E-03 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	3.2E-05	N/A	N/A	131.7	1.4E-04	N/A	N/A
		Toluene	108-88-3	3.4E-03 lb/MMcf	AP-42 Section 1.4	N/A	N/A	N/A	1.5E-02	5.1E-05	N/A	N/A	131.7	2.2E-04	N/A	N/A

DEP7007N
(continued)

SECTION II. Stack Information

KyEIS Source ID	Process ID	Stack Description	Stack Physical Data: Height (ft)	Stack Physical Data: Diameter (ft)	Stack Physical Data: Vent Height (ft)	Stack Geographic Data: Vertical Coordinate	Stack Geographic Data: Horizontal Coordinate	Stack Geographic Data: Coordinate Collection Method Code	Stack Gas Stream Data: Flowrate (acfm)	Stack Gas Stream Data: Temperature (F)	Stack Gas Stream Data: Exit Velocity (ft/sec)
EU09	1	Combined Cycle Combustion Turbine #1 - 100% Load	180.00	21.00	N/A	4,135,367	488,954	INI	1,242,857	201.4	59.81
EU10	1	Combined Cycle Combustion Turbine #2 - 100% Load	180.00	21.00	N/A	4,135,321	488,983	INI	1,242,857	201.4	59.81
EU11	1	Auxiliary Boiler	42.00	3.50	N/A	4,135,345	488,867	INI	35,005	622.0	60.00
EU12	1	Cooling Tower	64.00	32.00	N/A	4,135,393	488,985	INI	1,447,000	Ambient	25.00
EU13	1	Emergency Generator	11.00	0.67	N/A	4,135,369	488,900	INI	5,647	950.0	270.00
EU14	1	Fire Pump Engine	10.00	0.50	N/A	4,135,427	488,836	INI	3,164	905.0	270.00
EU15	1	Fuel Gas Heater	10.00	1.33	N/A	4,135,183	488,890	INI	5,306	1,000.0	63.34

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C01	*Oxidation catalyst*	*Johnson-Matthey (or equivalent)*		*Construction projected to commence in 2015*	*$1,400,000*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
1182 °F *639* °C	*1,201,186*	*0.075*	*N/A*	*N/A*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Oxidation catalyst. Listed removal efficiency is for normal operation.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
Defined upon finalization of system design	*CO, VOC, HAPs*	*Normal operation efficiency - 50%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C02	*Oxidation catalyst*	*Johnson-Matthey (or equivalent)*		*Construction projected to commence in 2015*	*$1,400,000*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
1182 °F *639* °C	*1,201,186*	*0.075*	*N/A*	*N/A*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Oxidation catalyst. Listed removal efficiency is for normal operation.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
Defined upon finalization of system design	*CO, VOC, HAPs*	*Normal operation efficiency - 50%*

DEP7007N
(continued)

SECTION III.	**Control Equipment Information for Other Type of Control Equipment**				
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C03	*Selective Catalytic Reduction*	*Johnson-Matthey (or equivalent)*		*Construction projected to commence in 2015*	*$600,000*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
1182 °F *639* °C	*1,201,186*	*0.075*	*N/A*	*N/A*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Selective catalytic reduction. Listed control efficiency is the minimum for normal operating scenarios.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
Defined upon finalization of system design	*NO_X*	*Minimum normal operation efficiency - 41.8%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C04	Selective Catalytic Reduction	Johnson-Matthey (or equivalent)		Construction projected to commence in 2015	$600,000

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
1182 °F 639 °C	1,201,186	0.075	N/A	N/A

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Selective catalytic reduction. Listed control efficiency is the minimum for normal operating scenarios.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
Defined upon finalization of system design	NO_X	Minimum normal operation efficiency - 41.8%

Commonwealth of Kentucky
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Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance Activities

APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Applicable Requirement, Standard, Restriction, Limitation, or Exemption[5]	Method of Determining Compliance with the Emission and Operating Requirement(s)[6]
EU09 & EU10	Combustion Turbine #1 & Combustion Turbine #2	CO	401 KAR 51:017	2.0 ppmvd at 15% O_2	Oxidation catalyst
		GHG	401 KAR 51:017	1,000 lb CO_2/MW-hr gross	High efficiency design; Fuel selection; Good combustion, operating, and maintenance practices
		NO_X	40 CFR 60 Subpart KKKK	15 ppm at 15% O_2	Monitoring as required by 40 CFR 60 Subpart KKKK (NO_X CEMS)
			401 KAR 51:210	CAIR	NO_X Annual Trading Program
			401 KAR 51:220	CAIR	NO_X Ozone Season Trading Program
		SO_2	40 CFR 60 Subpart KKKK	0.90 lb/MW-hr gross output or 0.060 lb/MMBtu heat input; 20 grains sulfur per 100 scf	Monitoring of fuel sulfur content or exemption per 60.4365
			401 KAR 51:230	CAIR	SO_2 Trading Program
		VOC	401 KAR 51:017	2.0 ppmvd at 15% O_2	Oxidation catalyst
EU11	Auxiliary Boiler	CO	401 KAR 51:017	0.075 lb/MMBtu	Good design and combustion practices
		GHG	401 KAR 51:017	51,199 tpy CO_2e	Efficient boiler selection; Fuel selection; Good combustion practices
		Opacity	401 KAR 59:015	No visible emissions greater than 20 percent opacity except for one 6-minute period per hour not to exceed 40 percent during cleaning the fire box or blowing soot.	Monthly Method 22 visible emissions observation followed by a Method 9 opacity performance test if necessary
		PM	401 KAR 59:015	0.33 lb/MMBtu	Utilizing only natural gas as fuel
		SO_2	401 KAR 59:015	1.17 lb MMBtu	Utilizing only natural gas as fuel
		VOC	401 KAR 51:017	0.0055 lb/MMBtu	Good design and combustion practices
EU13	Emergency Generator	N/A	40 CFR 60 Subpart IIII	Operating hours	Operation not to exceed 100 hours per year and operation in non-emergency situations must not exceed 50 hours per year
			40 CFR 60 Subpart IIII	Work practice	Install, configure, operate and maintain ICE according to manufacturer's emission-related written instructions
			40 CFR 60 Subpart IIII	Fuel usage	Usage of diesel fuel that meets the requirements of 40 CFR 80.510(b)
		CO	40 CFR 60 Subpart IIII	3.5 g/kW-hr	Purchasing ICEs certified by manufacturer to meet limit
			401 KAR 51:017	2.6 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit
		GHG	401 KAR 51:017	311 tpy CO_2e	Fuel records and 40 CFR 98 Subpart C emission factors
		NMHC + NOX	40 CFR 60 Subpart IIII	6.4 g/kW-hr	Purchasing ICEs certified by manufacturer to meet limit
		Opacity	40 CFR 60 Subpart IIII	20% opacity in acceleration mode, 15% opacity in lugging mode, and 50% opacity during peaks	Measuring according to 40 CFR 86 Subpart I
		PM	40 CFR 60 Subpart IIII	0.20 g/kW-hr	Purchasing ICEs certified by manufacturer to meet limit
		VOC	401 KAR 51:017	0.03 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit
EU14	Fire Pump Engine	N/A	40 CFR 60 Subpart IIII	Operating hours	Operation not to exceed 100 hours per year and operation in non-emergency situations must not exceed 50 hours per year
			40 CFR 60 Subpart IIII	Fuel usage	Usage of diesel fuel that meets the requirements of 40 CFR 80.510(b)
		CO	401 KAR 51:017	0.7 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit
		GHG	401 KAR 51:017	145 tpy CO_2e	Fuel records and 40 CFR 98 Subpart C emission factors
		NMHC + NOX	40 CFR 60 Subpart IIII	3.0 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit
		PM	40 CFR 60 Subpart IIII	0.15 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit
		VOC	401 KAR 51:017	0.09 g/hp-hr	Purchasing ICEs certified by manufacturer to meet limit

Commonwealth of Kentucky
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DEP7007V

Applicable Requirements & Compliance Activities

APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
EU15	Fuel Gas Heater	CO	401 KAR 51:017	0.08 lb/MMBtu	Good design and combustion practices
		GHG	401 KAR 51:017	7,687 tpy CO_2e	Fuel selection & good combustion practices
		Opacity	401 KAR 59:015	No visible emissions greater than 20 percent opacity except for one 6-minute period per hour not to exceed 40 percent during cleaning the fire box or blowing soot	Monthly Method 22 visible emissions observation followed by a Method 9 opacity performance test if necessary
		PM	401 KAR 59:015	0.51 lb/MMBtu	Usage of natural gas
		SO_2	401 KAR 59:015	2.54 lb/MMBtu	Usage of natural gas
		VOC	401 KAR 51:017	0.01 lb/MMBtu	Good design and combustion practices

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continued

APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)
EU09 & EU10	Combustion Turbine #1 & Combustion Turbine #2	NO_X	40 CFR 60 Subpart KKKK	Hourly NO_X emissions	Monitoring as required by 40 CFR 60 Subpart KKKK (NO_X CEMS)
			401 KAR 51:210	Annual NO_X emissions	Monitoring as required by 401 KAR 51:210 (NO_X CEMS)
			401 KAR 51:220	Ozone season NO_X emissions	Monitoring as required by 401 KAR 51:220 (NO_X CEMS)
		CO	401 KAR 51:017	Oxidation catalyst operating temperature	Continuous temperature monitoring (reading every 15 minutes)
		VOC	401 KAR 51:017	Oxidation catalyst operating temperature	Continuous temperature monitoring (reading every 15 minutes)
		SO_2	40 CFR 60 Subpart KKKK	Fuel Sulfur Content	Monitoring of sulfur content of fuel
			401 KAR 51:230	Annual SO_2 emissions	Monitoring as required by 401 KAR 51:230
EU11	Auxiliary Boiler	N/A	40 CFR 60 Subpart Dc	Fuel combusted	Monitor quantity of fuel combusted in each unit
		CO	401 KAR 51:017	CO emissions	Record fuel combusted in heaters for use in emission calculations
		GHG	401 KAR 51:017	GHG emissions	Record fuel combusted in heaters for use in emission calculations
		Opacity	401 KAR 59:015	Opacity	Monthly Method 22 visible emissions observations followed by a Method 9 opacity performance test if necessary
		VOC	401 KAR 51:017	VOC emissions	Record fuel combusted in heaters for use in emission calculations
EU13	Emergency Generator	N/A	40 CFR 60 Subpart IIII	Operating hours	Monitor hours of operation
EU14	Fire Pump Engine	N/A	40 CFR 60 Subpart IIII	Operating hours	Monitor hours of operation
EU15	Fuel Gas Heater	N/A	40 CFR 60 Subpart Dc	Fuel combusted	Monitor quantity of fuel combusted in each unit
		CO	401 KAR 51:017	CO emissions	Record fuel combusted in heaters for use in emission calculations
		GHG	401 KAR 51:017	GHG emissions	Record fuel combusted in heaters for use in emission calculations
		Opacity	401 KAR 59:015	Opacity	Monthly Method 22 visible emissions observations followed by a Method 9 opacity performance test if necessary
		VOC	401 KAR 51:017	VOC emissions	Record fuel combusted in heaters for use in emission calculations

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continued

APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.[1]	Emission Unit Description[2]	Contaminant[3]	Origin of Requirement or Standard[4]	Parameter Recorded[9]	Description of Recordkeeping[10]
EU09 & EU10	Combustion Turbine #1 & Combustion Turbine #2	NO_X	40 CFR 60 Subpart KKKK	Hourly NO_X emissions	Maintain records as required by 40 CFR 60 Subpart KKKK
			401 KAR 51:210	Annual NO_X emissions	Maintain records as required by 401 KAR 51:210
			401 KAR 51:220	Ozone season NO_X emissions	Maintain records as required by 401 KAR 51:220
		SO_2	40 CFR 60 Subpart KKKK	Fuel Sulfur Content	Maintain records of fuel sulfur content
			401 KAR 51:230	Annual SO_2 emissions	Maintain records as required by 401 KAR 51:230
EU11	Auxiliary Boiler	N/A	40 CFR 60 Subpart Dc	Fuel combusted	Maintain records of fuel combusted
		CO	401 KAR 51:017	CO emissions	Maintain records of fuel combusted
		GHG	401 KAR 51:017	GHG emissions	Maintain records of fuel combusted
		Opacity	401 KAR 59:015	Opacity	Maintain records of opacity observations and all performance tests
		VOC	401 KAR 51:017	VOC emissions	Maintain records of fuel combusted
EU13	Emergency Generator	N/A	40 CFR 60 Subpart IIII	Operating hours	Record hours of operation
EU14	Fire Pump Engine	N/A	40 CFR 60 Subpart IIII	Operating hours	Record hours of operation
EU15	Fuel Gas Heater	N/A	40 CFR 60 Subpart Dc	Fuel combusted	Maintain records of fuel combusted
		CO	401 KAR 51:017	CO emissions	Maintain records of fuel combusted
		GHG	401 KAR 51:017	GHG emissions	Maintain records of fuel combusted
		Opacity	401 KAR 59:015	Opacity	Maintain records of opacity observations and all performance tests
		VOC	401 KAR 51:017	VOC emissions	Maintain records of fuel combusted

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continued

APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION IV. REPORTING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Reported(11)	Description of Reporting(12)
EU09 & EU10	Combustion Turbine #1 & Combustion Turbine #2	CO	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing
		NO_X	40 CFR 60 Subpart KKKK	Hourly NO_X emissions	Semi-annual excess emissions and monitoring systems performance report
			KAR 51:210	Annual NO_X emissions	Required reporting under 40 CFR 75 and 40 CFR 96
			KAR 51:220	Ozone season NO_X emissions	Required reporting under 40 CFR 75 and 40 CFR 96
		SO_2	40 CFR 60 Subpart KKKK	Fuel sulfur content	Semi-annual excess emissions report
			KAR 51:230	Annual SO_2 emissions	Required reporting under 40 CFR 75 and 40 CFR 96
		VOC	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing
EU11	Auxiliary Boiler	CO	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing
		VOC	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing
EU15	Fuel Gas Heater	CO	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing
		VOC	401 KAR 51:017	Initial Compliance Test Results	Submit test reports after completion of testing

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APPLICANT NAME: *Kentucky Utilities Company/Green River Generating Station*

SECTION V. TESTING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Tested(13)	Description of Testing(14)
EU09 & EU10	Combustion Turbine #1 & Combustion Turbine #2	CO	401 KAR 51:017	CO emissions	Initial compliance test
		GHG	401 KAR 51:017	CO_2 emissions	Initial compliance test
		NO_X	40 CFR 60 Subpart KKKK	Hourly NO_X emissions	Testing as required by 40 CFR 60 Subpart KKKK
			401 KAR 51:210	Annual NO_X emissions	Testing as required by 401 KAR 51:210
			401 KAR 51:220	Ozone season NO_X emissions	Testing as required by 401 KAR 51:220
		SO_2	40 CFR 60 Subpart KKKK	Fuel Sulfur Content	Periodic testing of fuel sulfur content
			401 KAR 51:230	Annual SO_2 emissions	Testing as required by 401 KAR 51:230
		VOC	401 KAR 51:017	VOC emissions	Initial compliance test
EU11	Auxiliary Boiler	CO	401 KAR 51:017	CO emissions	Initial compliance test
		Opacity	401 KAR 59:015	Fuel usage and heat content, Hours of operation	Method 9 opacity performance tests if necessary
		VOC	401 KAR 51:017	VOC emissions	Initial compliance test
EU13	Emergency Generator	Opacity	40 CFR 60 Subpart IIII	Opacity	Measuring according to 40 CFR 86 Subpart I
EU15	Fuel Gas Heater	CO	401 KAR 51:017	CO emissions	Initial compliance test
		Opacity	401 KAR 59:015	Opacity	Method 9 opacity performance tests if necessary
		VOC	401 KAR 51:017	VOC emissions	Initial compliance test

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007DD
INSIGNIFICANT ACTIVITIES

INSIGNIFICANT ACTIVITY CRITERIA

1. Emissions from insignificant activities shall be counted toward the source's potential to emit;
2. Emissions from the activity shall not be subject to a federally enforceable requirement other than generally applicable requirements that apply to all activities and affected facilities such as 401 KAR 59:010, 61:020, 63:010, and others deemed generally applicable by the Cabinet;
3. The potential to emit a regulated air pollutant from the activity or affected facility shall not exceed 5 tons/yr.
4. The potential to emit of a hazardous air pollutant from the activity or affected facility shall not exceed 1,000 pounds/yr., or the deminimis level established under Section 112(g) of the Act, whichever is less;
5. The activity shall be included in the permit application, identifying generally applicable and state origin requirements.

Description of Activity Including Rated Capacity	Generally Applicable Regulations Or State Origin Requirements	Does the Activity meet the Insignificant Activity Criteria?
Unleaded Gasoline Tank (500 gal) - Existing	None	Yes
Various Lubricating Oil Tanks - Existing	None	Yes
Kerosene Tank (300 gal) - Existing	None	Yes
Diesel Tank #3 (300 gal) - Existing	None	Yes
Diesel Tank #4 (2,000 gal) - Existing	None	Yes
Diesel Tank #5 (1,000 gal) - Existing	None	Yes
Kerosene Heaters - Existing	None	Yes
Diesel Tank #6 (660 gal)	None	Yes
Diesel Tank #7 (849 gal)	None	Yes
Lube Oil Tank #1 (8,400 gal)	401 KAR 59:050	Yes
Lube Oil Tank #2 (8,400 gal)	401 KAR 59:050	Yes
Lube Oil Tank #3 (12,050 gal)	None	Yes
Demister Vents	None	Yes

SIGNATURE BLOCK

I, THE UNDERSIGNED, HEREBY CERTIFY UNDER PENALTY OF LAW, THAT I AM A RESPONSIBLE OFFICIAL, AND

BY Ralph Bowling
Authorized Signature

2/28/14
Date

Ralph Bowling
Typed or Printed Name of Signatory

Vice President Power Production
Title of Signatory

APPENDIX C: EMISSION CALCULATIONS

Table C-1. Summary of Net Emissions Increases Associated with NGCC Project

New Emission Units PTE (tpy)										
	NO_X	**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**SAM**	**Lead**	**CO_2e[1]**
Combustion Turbine #1 - Option A	615.7	74.8	28.3	56.5	56.5	647.9	25.7	27.5	-	1,332,454
Combustion Turbine #2 - Option A	615.7	74.8	28.3	56.5	56.5	647.9	25.7	27.5	-	1,332,454
Combustion Turbine #1 - Option B	753.8	234.1	31.4	62.8	62.8	719.8	105.8	30.6	-	1,480,291
Combustion Turbine #2 - Option B	753.8	234.1	31.4	62.8	62.8	719.8	105.8	30.6	-	1,480,291
Combustion Turbine #1 - Option C	693.3	186.1	31.8	63.5	63.5	728.2	32.2	30.9	-	1,497,205
Combustion Turbine #2 - Option C	693.3	186.1	31.8	63.5	63.5	728.2	32.2	30.9	-	1,497,205
Steam Turbine #1	-	-	-	-	-	-	-	-	-	0.56
Auxiliary Boiler	15.8	32.8	3.1	3.1	3.1	1.3	2.4	-	< 0.1	51,199
Cooling Tower	-	-	2.3	1.6	< 0.1	-	-	-	-	-
Emergency Generator	2.9	0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	-	-	311
Fire Pump Engine	0.8	0.2	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	-	-	145
Fuel Gas Heater	3.9	5.5	0.5	0.5	0.5	0.2	0.4	-	< 0.1	7,687
Tanks	-	-	-	-	-	-	< 0.1	-	-	-
Demister Vents	-	-	0.9	0.9	0.9	-	0.9	-	-	-
Circuit Breakers	-	-	-	-	-	-	-	-	-	161
Fugitive Components	-	-	-	-	-	-	-	-	-	631
Facility Total - Option A	**1,254.8**	**188.4**	**63.3**	**119.2**	**117.6**	**1,297.4**	**55.1**	**55.1**	**< 0.1**	**2,725,043**
Facility Total - Option B	**1,531.0**	**506.8**	**69.6**	**131.8**	**130.1**	**1,441.0**	**215.4**	**61.2**	**< 0.1**	**3,020,717**
Facility Total - Option C	**1,410.1**	**410.9**	**70.3**	**133.2**	**131.6**	**1,457.9**	**68.3**	**61.9**	**< 0.1**	**3,054,545**

Emissions Decreases from Coal-Fired Boilers Shutdown (tpy)										
	NO_X	**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**SAM**	**Lead**	**CO_2e**
Boiler #4	806.8	39.8	181.4	500.0	431.0	7,110.3	4.8	88.0	< 0.1	384,754
Boiler #5	1,258.9	74.6	274.7	833.9	729.5	11,625.7	8.9	143.9	< 0.1	620,063
Facility Total	**2,065.7**	**114.3**	**456.1**	**1,333.9**	**1,160.6**	**18,736.0**	**13.7**	**231.8**	**< 0.1**	**1,004,817**

Net Emissions Increase/Decrease (tpy)										
	NO_X	**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**SAM**	**Lead**	**CO_2e**
Net Emissions Change - Option A[2]	**(810.8)**	**74.0**	**(392.8)**	**(1,214.6)**	**(1,043.0)**	**(17,438.5)**	**41.4**	**(176.8)**	**(0.1)**	**1,720,226**
Net Emissions Change - Option B[2]	**(534.7)**	**392.5**	**(386.6)**	**(1,202.1)**	**(1,030.4)**	**(17,294.9)**	**201.7**	**(170.7)**	**(0.1)**	**2,015,900**
Net Emissions Change - Option C[2]	**(655.6)**	**296.6**	**(385.8)**	**(1,200.6)**	**(1,029.0)**	**(17,278.1)**	**54.6**	**(169.9)**	**(0.1)**	**2,049,728**
SER	**40**	**100**	**25**	**15**	**10**	**40**	**40**	**7**	**0.6**	**75,000**
Exceeds SER? (Option A)	**No**	**No**	**No**	**No**	**No**	**No**	**Yes**	**No**	**No**	**Yes**
Exceeds SER? (Option B)	**No**	**Yes**	**No**	**No**	**No**	**No**	**Yes**	**No**	**No**	**Yes**
Exceeds SER? (Option C)	**No**	**Yes**	**No**	**No**	**No**	**No**	**Yes**	**No**	**No**	**Yes**

1. The PTE for CO_2e from each combustion turbine includes potential emissions from the worst-case operation scenario on an annual basis (i.e., worst-case of continuous annual operation vs. operation maximum startups and shutdowns) and potential emissions from maintenance CO_2 purging.
2. Project facility total emissions increase (Step 1) minus contemporaneous decreases (Step 2).

Appendix C - Emission Calculations

Table C-2. Summary of Potential HAP Emissions

	Controlled PTE[1,2]												
	1,3-Butadiene (tpy)	Acetaldehyde (tpy)	Acrolein (tpy)	Benzene (tpy)	Ethylbenzene (tpy)	Formaldehyde (tpy)	Naphthalene (tpy)	PAH (tpy)	Propylene Oxide (tpy)	Toluene (tpy)	Xylene (total) (tpy)	Hexane (tpy)	Nickel (tpy)
Combustion Turbine #1 - Option A	< 0.1	0.4	< 0.1	0.1	0.2	1.9	< 0.1	< 0.1	0.2	0.6	0.6	-	-
Combustion Turbine #2 - Option A	< 0.1	0.4	< 0.1	0.1	0.2	1.9	< 0.1	< 0.1	0.2	0.6	0.6	-	-
Combustion Turbine #1 - Option B	< 0.1	0.8	< 0.1	0.2	0.4	4.5	< 0.1	< 0.1	0.5	1.2	1.1	-	-
Combustion Turbine #2 - Option B	< 0.1	0.8	< 0.1	0.2	0.4	4.5	< 0.1	< 0.1	0.5	1.2	1.1	-	-
Combustion Turbine #1 - Option C	< 0.1	0.7	< 0.1	0.2	0.3	3.5	< 0.1	< 0.1	0.4	1.0	1.0	-	-
Combustion Turbine #2 - Option C	< 0.1	0.7	< 0.1	0.2	0.3	3.5	< 0.1	< 0.1	0.4	1.0	1.0	-	-
Steam Turbine #1	-	-	-	-	-	-	-	-	-	-	-	-	-
Auxiliary Boiler	-	-	-	< 0.1	-	< 0.1	-	-	-	< 0.1	-	0.8	< 0.1
Cooling Tower	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Generator	-	-	-	< 0.1	-	< 0.1	< 0.1	-	-	< 0.1	< 0.1	-	-
Fire Pump Engine	-	< 0.1	-	< 0.1	-	< 0.1	-	-	-	< 0.1	< 0.1	-	-
Fuel Gas Heater	-	-	-	< 0.1	-	< 0.1	-	-	-	< 0.1	-	0.1	< 0.1
Tanks	-	-	-	-	-	-	-	-	-	< 0.1	< 0.1	-	-
Demister Vents	-	-	-	-	-	-	-	-	-	-	-	-	-
Circuit Breakers	-	-	-	-	-	-	-	-	-	-	-	-	-
Fugitive Components	-	-	-	-	-	-	-	-	-	-	-	-	-
Facility Total - Option A	**< 0.1**	**0.7**	**0.1**	**0.2**	**0.4**	**3.9**	**< 0.1**	**< 0.1**	**0.5**	**1.2**	**1.1**	**0.9**	**< 0.1**
Facility Total - Option B	**< 0.1**	**1.5**	**0.2**	**0.5**	**0.8**	**9.0**	**< 0.1**	**< 0.1**	**1.0**	**2.4**	**2.3**	**0.9**	**< 0.1**
Facility Total - Option C	**< 0.1**	**1.3**	**0.2**	**0.4**	**0.7**	**7.1**	**< 0.1**	**< 0.1**	**0.9**	**2.1**	**2.0**	**0.9**	**< 0.1**

1. For natural gas combustion units, the top 5 HAP are included, except for the NGCC combustion turbines, for which all HAP are included
2. Potential HAP emissions are included for proposed emission units. Existing emission units include one (1) emergency generator (EU08) with potential HAP emissions assumed to be comparable to those from the proposed emergency generator and several insignificant activities (i.e., kerosene heaters and several diesel, gasoline, lubricating oil, and kerosene storage tanks); potential HAP emissions from existing emission units are trivial and will not impact the source classification.

	Highest Single HAP (tpy)	Total Combined HAP (tpy)
Facility Total - Option A	3.9	9.0
Facility Total - Option B	9.0	18.6
Facility Total - Option C	7.1	15.5

Appendix C - Emission Calculations

Table C-3. NGCC Combustion Turbine Potential NSR-Regulated Pollutant and GHG Emissions

NGCC Data - Option A

Potential Hours of Operation 8,760 hr/yr

	Maximum # Events	Event Duration	Total Event Hours	Minimum Downtime Per Event	Total Event & Downtime Hours
Number of Cold Starts	- events/yr	1.08 hr/event	- hr/yr	60 hr/event	- hr/yr
Number of Warm Starts	52 events/yr	0.75 hr/event	39.0 hr/yr	10 hr/event	559 hr/yr
Number of Hot Starts	208 events/yr	0.50 hr/event	104.0 hr/yr	1 hr/event	312 hr/yr
Number of Shutdowns	260 events/yr	0.38 hr/event	99.7 hr/yr	- hr/event	100 hr/yr

Controlled Potential Emissions (per combustion turbine)

Pollutant	Normal Operation[1] (lb/hr)	Cold Startup[2] (lb/hr)	Warm Startup[2] (lb/hr)	Hot Startup[2] (lb/hr)	Shutdown[2] (lb/hr)	Continuous Normal Operation[3] (tpy)	Operation with Maximum Startups & Shutdowns[4] (tpy)	Worst-Case Potential Emissions (lb/hr)[5]	Worst-Case Potential Emissions (tpy)[6]
CO	11.41	114.18	160.04	234.57	302.61	49.97	74.83	302.61	74.83
NO_X (as NO_2)	140.58	81.14	74.09	62.63	52.17	615.72	554.80	140.58	615.72
PM Filterable	6.46	6.46	6.46	6.46	6.46	28.27	25.92	6.46	28.27
Total PM/PM_{10}/$PM_{2.5}$	12.91	12.91	12.91	12.91	12.91	56.55	51.85	12.91	56.55
SO_2[6]	147.93	147.93	147.93	147.93	147.93	647.95	594.10	147.93	647.95
VOC	1.88	66.07	94.69	141.19	183.65	8.23	25.66	183.65	25.66
SAM[6]	6.29	6.29	6.29	6.29	6.29	27.54	25.25	6.29	27.54
CO_2	303,901	102,345	84,236	54,808	26,988	1,331,087	1,189,431	303,901	1,331,087
N_2O	0.57	0.19	0.16	0.10	0.05	2.49	2.23	0.57	2.49
CH_4	5.69	1.93	1.58	1.03	0.52	24.93	22.28	5.69	24.93

1. Normal operation emission rates (lb/hr) are based on manufacturer emissions data for the worst-case operation scenario, except for N_2O and CH_4 emission rates, which are based on the combustion turbine maximum heat input (MMBtu/hr) during normal operation and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.

2. Startup and shutdown event hourly emission rates (lb/hr) for CO, NO_X, and VOC are calculated by dividing lb/event emissions data by the event duration; emission rates would not be sustained for an entire hour for in cases where the startup/shutdown duration is less than 1 hour. Startup and shutdown event hourly emission rates (lb/hr) for PM Filterable, Total PM/PM_{10}/$PM_{2.5}$, SO_2 and SAM are conservatively assumed to be equal to hourly emission rates during normal operation. Startup and shutdown hourly emission rates (lb/hr) for CO_2, N_2O, and CH_4 are calculated based on the maximum heat input (MMBtu/hr) for each startup/shutdown event type and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.

3. Based on 8,760 hr/yr of normal operations.

4. Based on maximum number of hours of each startup or shutdown per year multiplied by the lb/hr emission rate for each event type plus normal operation for the remainder of the year (8,760 hr/yr - total event & downtime hours).

5. Based on the worst-case of normal, startup (cold, warm or hot), or shutdown operations.

6. Based on the worst-case continuous normal operation or operation with maximum startups and shutdowns.

Table C-3. NGCC Combustion Turbine Potential NSR-Regulated Pollutant and GHG Emissions

NGCC Data - Option B

Potential Hours of Operation 8,760 hr/yr

	Maximum # Events	Event Duration	Total Event Hours	Minimum Downtime Per Event	Total Event & Downtime Hours
Number of Cold Starts	- events/yr	1.08 hr/event	- hr/yr	60 hr/event	- hr/yr
Number of Warm Starts	52 events/yr	0.75 hr/event	39.0 hr/yr	10 hr/event	559 hr/yr
Number of Hot Starts	208 events/yr	0.50 hr/event	104.0 hr/yr	1 hr/event	312 hr/yr
Number of Shutdowns	260 events/yr	0.30 hr/event	78.0 hr/yr	- hr/event	78 hr/yr

Controlled Potential Emissions (per combustion turbine)

Pollutant	Normal Operation[1] (lb/hr)	Cold Startup[2] (lb/hr)	Warm Startup[2] (lb/hr)	Hot Startup[2] (lb/hr)	Shutdown[2] (lb/hr)	Continuous Normal Operation[3] (tpy)	Operation with Maximum Startups & Shutdowns[4] (tpy)	Worst-Case Potential Emissions (lb/hr)[5]	Worst-Case Potential Emissions (tpy)[6]
CO	13.78	914.82	1,312.17	1,957.85	1,354.50	60.37	234.05	1,957.85	234.05
NO_X (as NO_2)	172.10	109.15	112.11	116.92	99.33	753.81	684.29	172.10	753.81
PM Filterable	7.17	7.17	7.17	7.17	7.17	31.41	28.80	7.17	31.41
Total $PM/PM_{10}/PM_{2.5}$	14.34	14.34	14.34	14.34	14.34	62.81	57.59	14.34	62.81
SO_2[6]	164.33	164.33	164.33	164.33	164.33	719.75	659.94	164.33	719.75
VOC	4.02	487.36	702.25	1,051.46	556.80	17.62	105.80	1,051.46	105.80
SAM[6]	6.98	6.98	6.98	6.98	6.98	30.59	28.04	6.98	30.59
CO_2	337,619	157,368	146,087	127,756	121,192	1,478,772	1,332,791	337,619	1,478,772
N_2O	0.63	0.29	0.27	0.23	0.23	2.77	2.50	0.63	2.77
CH_4	6.32	2.94	2.71	2.35	2.32	27.70	24.96	6.32	27.70

1. Normal operation emission rates (lb/hr) are based on manufacturer emissions data for the worst-case operation scenario, except for N_2O and CH_4 emission rates, which are based on the combustion turbine maximum heat input (MMBtu/hr) during normal operation and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.
2. Startup and shutdown event hourly emission rates (lb/hr) for CO, NO_X, and VOC are calculated by dividing lb/event emissions data by the event duration; emission rates would not be sustained for an entire hour for in cases where the startup/shutdown duration is less than 1 hour. Startup and shutdown event hourly emission rates (lb/hr) for PM Filterable, Total $PM/PM_{10}/PM_{2.5}$, SO_2 and SAM are conservatively assumed to be equal to hourly emission rates during normal operation. Startup and shutdown hourly emission rates (lb/hr) for CO_2, N_2O, and CH_4 are calculated based on the maximum heat input (MMBtu/hr) for each startup/shutdown event type and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.
3. Based on 8,760 hr/yr of normal operations.
4. Based on maximum number of hours of each startup or shutdown per year multiplied by the lb/hr emission rate for each event type plus normal operation for the remainder of the year (8,760 hr/yr - total event & downtime hours).
5. Based on the worst-case of normal, startup (cold, warm or hot), or shutdown operations.
6. Based on the worst-case continuous normal operation or operation with maximum startups and shutdowns.

Appendix C - Emission Calculations

Table C-3. NGCC Combustion Turbine Potential NSR-Regulated Pollutant and GHG Emissions

NGCC Data - Option C

Potential Hours of Operation 8,760 hr/yr

	Maximum # Events	Event Duration	Total Event Hours	Minimum Downtime Per Event	Total Event & Downtime Hours
Number of Cold Starts	- events/yr	1.08 hr/event	- hr/yr	60 hr/event	- hr/yr
Number of Warm Starts	52 events/yr	0.75 hr/event	39.0 hr/yr	10 hr/event	559 hr/yr
Number of Hot Starts	208 events/yr	0.50 hr/event	104.0 hr/yr	1 hr/event	312 hr/yr
Number of Shutdowns	260 events/yr	0.18 hr/event	47.7 hr/yr	- hr/event	48 hr/yr

Controlled Potential Emissions (per combustion turbine)

Pollutant	Normal Operation[1] (lb/hr)	Cold Startup[2] (lb/hr)	Warm Startup[2] (lb/hr)	Hot Startup[2] (lb/hr)	Shutdown[2] (lb/hr)	Continuous Normal Operation[3] (tpy)	Operation with Maximum Startups & Shutdowns[4] (tpy)	Worst-Case Potential Emissions (lb/hr)[5]	Worst-Case Potential Emissions (tpy)[6]
CO	12.85	583.23	833.56	1,240.33	2,307.27	56.27	186.11	2,307.27	186.11
NO_X (as NO_2)	158.30	187.88	198.49	215.73	278.18	693.34	642.35	278.18	693.34
PM Filterable	7.25	7.25	7.25	7.25	7.25	31.77	29.13	7.25	31.77
Total $PM/PM_{10}/PM_{2.5}$	14.51	14.51	14.51	14.51	14.51	63.55	58.27	14.51	63.55
SO_2[6]	166.25	166.25	166.25	166.25	166.25	728.17	667.65	166.25	728.17
VOC	1.90	105.34	151.34	226.09	423.27	8.32	32.25	423.27	32.25
SAM[6]	7.06	7.06	7.06	7.06	7.06	30.94	28.37	7.06	30.94
CO_2	341,477	172,876	162,502	145,644	134,420	1,495,669	1,352,763	341,477	1,495,669
N_2O	0.64	0.32	0.30	0.27	0.26	2.80	2.53	0.64	2.80
CH_4	6.40	3.24	3.04	2.71	2.60	28.02	25.34	6.40	28.02

1. Normal operation emission rates (lb/hr) are based on manufacturer emissions data for the worst-case operation scenario, except for N_2O and CH_4 emission rates, which are based on the combustion turbine maximum heat input (MMBtu/hr) during normal operation and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.
2. Startup and shutdown event hourly emission rates (lb/hr) for CO, NO_X, and VOC are calculated by dividing lb/event emissions data by the event duration; emission rates would not be sustained for an entire hour for in cases where the startup/shutdown duration is less than 1 hour. Startup and shutdown event hourly emission rates (lb/hr) for PM Filterable, Total $PM/PM_{10}/PM_{2.5}$, SO_2 and SAM are conservatively assumed to be equal to hourly emission rates during normal operation. Startup and shutdown hourly emission rates (lb/hr) for CO_2, N_2O, and CH_4 are calculated based on the maximum heat input (MMBtu/hr) for each startup/shutdown event type and GHG emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2. CO_2 emission rate includes emissions generated by the oxidation catalyst.
3. Based on 8,760 hr/yr of normal operations.
4. Based on maximum number of hours of each startup or shutdown per year multiplied by the lb/hr emission rate for each event type plus normal operation for the remainder of the year (8,760 hr/yr - total event & downtime hours).
5. Based on the worst-case of normal, startup (cold, warm or hot), or shutdown operations.
6. Based on the worst-case continuous normal operation or operation with maximum startups and shutdowns.

Table C-4. NGCC Combustion Turbine Potential HAP Emissions

Combustion Turbine - Option A

Heat Input (per Combustion Turbine)	2,582	MMBtu/hr (HHV), worst-case scenario
Hours of Normal Ops. per Year per CT	7,789	hr/yr
Hours of SU-SD per Year per CT	971	hr/yr
CO Control During Normal Ops.	80.0%	(from Oxidation Catalyst)
CO Control During SU-SD	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During Normal Ops.	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During SU-SD	20.0%	(from Oxidation Catalyst)
Worst-Case Uncontrolled CO Emission Factor	0.0141	lb/MMBtu, lowest CO emission factor is worst-case for potential HAP/TAP emission calculation approach

Pollutant	HAP (Yes/No)	Uncontrolled Emission Factor[1] (lb/MMBtu)	Basis	Controlled Potential Emissions - Normal Operation Per Combustion Turbine[2] (lb/hr)	(tpy)	Basis	Controlled Potential Emissions - SU-SD Per Combustion Turbine[3] (lb/hr)	(tpy)	Basis	Total Controlled Potential Emissions - Per Combustion Turbine[4] (tpy)
1,3-Butadiene	Yes	6.05E-08	A	7.81E-05	3.04E-04	C	2.07E-03	2.08E-04	E	5.12E-04
Acetaldehyde	Yes	4.31E-05	A	0.056	0.22	C	1.47	0.15	E	0.36
Acrolein	Yes	5.60E-06	A	0.007	0.028	C	0.19	0.019	E	0.05
Benzene	Yes	1.30E-05	A	0.017	0.066	C	0.45	0.045	E	0.11
Ethylbenzene	Yes	2.28E-05	A	0.029	0.115	C	0.78	0.079	E	0.19
Formaldehyde	Yes	2.41E-04	B	0.28	1.08	D	8.27	0.83	E	1.91
Naphthalene	Yes	6.33E-07	A	8.17E-04	3.18E-03	C	0.022	2.18E-03	E	5.36E-03
PAH	Yes	4.71E-07	A	6.07E-04	2.37E-03	C	0.016	1.62E-03	E	3.98E-03
Propylene Oxide	Yes	2.86E-05	A	0.037	0.14	C	0.98	0.098	E	0.24
Toluene	Yes	6.80E-05	A	0.088	0.34	C	2.33	0.23	E	0.58
Xylene (total)	Yes	6.51E-05	A	0.084	0.33	C	2.23	0.22	E	0.55
Total HAP				**0.60**	**2.33**		**16.74**	**1.68**		**4.01**
Maximum Single HAP				**0.28**	**1.08**		**8.27**	**0.83**		**1.91**

1. Emission Factor Basis Key
   A Emission factors are based on average of large (> 40 MW) natural gas-fired turbine test data based on background data documentation from AP-42 Section 3.1.
   B Highest formaldehyde emission factor from normal steady-state operation load/ambient condition cases provided by vendor.
2. Controlled Potential Emissions - Normal Operation Basis Key
   C Controlled hourly potential emission rates during normal operation are based on worst-case heat input (MMBtu/hr, HHV), assumed control efficiency associated with the Oxidation Catalyst, and AP-42 reference emissions factors for natural gas-fired turbines (refer to footnote 1.A above). Controlled annual potential emission rates during normal operation are based on hourly potential emission rates multiplied by the annual normal operating hours for the turbine.

   D Controlled hourly potential formaldehyde emission rate during normal operation is based on maximum hourly emission rate during normal steady-state operation load/ambient conditions provided by vendor. Controlled annual potential formaldehyde emission rate during normal operation is based on the hourly potential emission rate multiplied by the annual normal operating hours for turbine.
3. Controlled Potential Emission - SU-SD Basis Key
   E Controlled hourly potential emission rates during SU-SD are calculated as the maximum controlled hourly CO emission rate (lb/hr) for SU-SD events provided by the vendor divided by the expected CO control efficiency for the Oxidation Catalyst during SU-SD events to obtain an uncontrolled CO emission rate during SU-SD. The uncontrolled hourly CO emission rate during SU-SD is divided by the worst-case (lowest) CO emission factor (lb/MMBtu) provided by the vendor and multiplied by the uncontrolled emission factor for each organic pollutant listed to obtain an uncontrolled hourly organic emission rate (lb organic pollutant/hr). The uncontrolled hourly organic pollutant emission rate is multiplied by one minus the expected organic pollutant control efficiency for the Oxidation Catalyst during SU-SD events to obtain a controlled hourly organic pollutant potential emission rate during SU-SD. Please refer to the sample calculation below for the calculation of hourly controlled potential emissions for Formaldehyde:

   Hourly Controlled Potential Emissions - SU-SD
   1. 605.22 lb CO uncontrolled/hr 302.61 lb CO controlled/hr / 50.0%
   2. 10.33 lb Formaldehyde uncontrolled/hr 605.22 lb CO uncontrolled/hr / (0.014136 lb CO uncontrolled / MMBtu) x (0.0002 lb Formaldehyde uncontrolled / MMBtu)
   3. 8.27 lb Formaldehyde controlled/hr 10.33 lb Formaldehyde uncontrolled/hr x (100 - 20.0%)

   Controlled annual potential emission rates during SU-SD are calculated as the maximum controlled hourly CO emission rate (lb/hr) for SU-SD events provided by the vendor multiplied by the total event hours associated with the specific SU-SD event to obtain an annual controlled CO emission rate during SU-SD (tpy) (refer to emission rates (lb/hr) represented in Table C-3 Option A, B, and C). The controlled CO emission rate during SU-SD is divided by the expected CO control efficiency for the Oxidation Catalayst during SU-SD events to obtain an uncontrolled annual CO emission rate during SU-SD. The uncontrolled annual CO emission rate during SU-SD is divided by the worst-case (lowest) CO emission factor (lb/MMBtu) provided by the vendor and multiplied by the uncontrolled emission factor for each organic pollutant listed to obtian an uncontrolled annual organic emission rate (ton organic pollutant/yr). The uncontrolled annual organic pollutant emission rate is multiplied by one minus the expected organic pollutant control efficiency for the Oxidation Catalyst during SU-SD events to obtain a controlled annual organic pollutant potential emission rate during SU-SD. Please refer to the sample calculation below for the calculation of hourly controlled potential emissions for Formaldehyde:

   Annual Controlled Potential Emissions - SU-SD
   1. 60.8 ton CO uncontrolled/yr 30.40 ton CO controlled/yr / 50.0%
   2. 0.2798 ton Formaldehyde uncontrolled/yr 60.80 ton CO uncontrolled/yr / (0.0141 lb CO uncontrolled / MMBtu) x (0.0002 lb Formaldehyde uncontrolled / MMBtu)
   3. 0.83 ton Formaldehyde controlled/yr 1.04 ton Formaldehyde uncontrolled/yr x (100 - 20.0%)
4. Worst-case annual emission rate calculated as the sum of the controlled annual HAP emission rate during normal operation and the controlled annual HAP emission rate during SU-SD events.

Table C-4. NGCC Combustion Turbine Potential HAP Emissions

Combustion Turbine - Option B

Heat Input (per Combustion Turbine)	2,868	MMBtu/hr (HHV), worst-case scenario
Hours of Normal Ops. per Year per CT	7,811	hr/yr
Hours of SU-SD per Year per CT	949	hr/yr
CO Control During Normal Ops.	80.0%	(from Oxidation Catalyst)
CO Control During SU-SD	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During Normal Ops.	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During SU-SD	20.0%	(from Oxidation Catalyst)
Worst-Case Uncontrolled CO Emission Factor	0.0240	lb/MMBtu, lowest CO emission factor is worst-case for potential HAP/TAP emission calculation approach

Pollutant	HAP (Yes/No)	Uncontrolled Emission Factor[1] (lb/MMBtu)	Basis	Controlled Potential Emissions - Normal Operation Per Combustion Turbine (lb/hr)[2]	(tpy)[3]	Basis	Controlled Potential Emissions - SU-SD Per Combustion Turbine (lb/hr)	(tpy)	Basis	Total Controlled Potential Emissions - Per Combustion Turbine[4] (tpy)
1,3-Butadiene	Yes	6.05E-08	A	8.68E-05	3.39E-04	C	7.89E-03	7.26E-04	E	1.07E-03
Acetaldehyde	Yes	4.31E-05	A	0.062	0.24	C	5.62	0.52	E	0.76
Acrolein	Yes	5.60E-06	A	0.008	0.031	C	0.73	0.067	E	0.10
Benzene	Yes	1.30E-05	A	0.019	0.073	C	1.70	0.157	E	0.23
Ethylbenzene	Yes	2.28E-05	A	0.033	0.128	C	2.98	0.274	E	0.40
Formaldehyde	Yes	2.65E-04	B	0.34	1.31	D	34.53	3.18	E	4.49
Naphthalene	Yes	6.33E-07	A	9.08E-04	3.55E-03	C	0.083	7.60E-03	E	1.11E-02
PAH	Yes	4.71E-07	A	6.75E-04	2.64E-03	C	0.061	5.65E-03	E	8.29E-03
Propylene Oxide	Yes	2.86E-05	A	0.041	0.16	C	3.73	0.343	E	0.50
Toluene	Yes	6.80E-05	A	0.097	0.38	C	8.86	0.82	E	1.20
Xylene (total)	Yes	6.51E-05	A	0.093	0.36	C	8.49	0.78	E	1.15
Total HAP				**0.69**	**2.70**		**66.79**	**6.15**		**8.85**
Maximum Single HAP				**0.34**	**1.31**		**34.53**	**3.18**		**4.49**

1. Emission Factor Basis Key
   A Refer to footnote 1.A for Combustion Turbine - Option A.
   B Refer to footnote 1.B for Combustion Turbine - Option A.
2. Controlled Potential Emissions - Normal Operation Basis Key
   C Refer to footnote 2.C for Combustion Turbine - Option A.
   D Refer to footnote 2.D for Combustion Turbine - Option A.
3. Controlled Potential Emission - SU-SD Basis Key
   E Refer to footnore 3.E for Combustion Turbine - Option A.
4. Worst-case annual emission rate calculated as the sum of the controlled annual HAP emission rate during normal operation and the controlled annual HAP emission rate during SU-SD events.

Table C-4. NGCC Combustion Turbine Potential HAP Emissions

Combustion Turbine - Option C

Heat Input (per Combustion Turbine)	2,902	MMBtu/hr (HHV), worst-case scenario
Hours of Normal Ops. per Year per CT	7,841	hr/yr
Hours of SU-SD per Year per CT	919	hr/yr
CO Control During Normal Ops.	80.0%	(from Oxidation Catalyst)
CO Control During SU-SD	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During Normal Ops.	50.0%	(from Oxidation Catalyst)
Organic Pollutant Control During SU-SD	20.0%	(from Oxidation Catalyst)
Worst-Case Uncontrolled CO Emission Factor	0.0229	lb/MMBtu, lowest CO emission factor is worst-case for potential HAP/TAP emission calculation approach

Pollutant	HAP (Yes/No)	Uncontrolled Emission Factor[1] (lb/MMBtu)	Basis	Controlled Potential Emissions - Normal Operation Per Combustion Turbine (lb/hr)[2]	(tpy)[3]	Basis	Controlled Potential Emissions - SU-SD Per Combustion Turbine (lb/hr)	(tpy)	Basis	Total Controlled Potential Emissions - Per Combustion Turbine[4] (tpy)
1,3-Butadiene	Yes	6.05E-08	A	8.78E-05	3.44E-04	C	9.77E-03	5.75E-04	E	9.19E-04
Acetaldehyde	Yes	4.31E-05	A	0.062	0.24	C	6.95	0.41	E	0.65
Acrolein	Yes	5.60E-06	A	0.008	0.032	C	0.90	0.053	E	0.08
Benzene	Yes	1.30E-05	A	0.019	0.074	C	2.11	0.124	E	0.20
Ethylbenzene	Yes	2.28E-05	A	0.033	0.130	C	3.69	0.217	E	0.35
Formaldehyde	Yes	2.42E-04	B	0.31	1.23	D	39.02	2.30	E	3.52
Naphthalene	Yes	6.33E-07	A	9.18E-04	3.60E-03	C	0.102	6.01E-03	E	9.61E-03
PAH	Yes	4.71E-07	A	6.83E-04	2.68E-03	C	0.076	4.47E-03	E	7.15E-03
Propylene Oxide	Yes	2.86E-05	A	0.041	0.16	C	4.62	0.272	E	0.43
Toluene	Yes	6.80E-05	A	0.099	0.39	C	10.97	0.65	E	1.03
Xylene (total)	Yes	6.51E-05	A	0.094	0.37	C	10.50	0.62	E	0.99
Total HAP				**0.67**	**2.63**		**78.94**	**4.64**		**7.28**
Maximum Single HAP				**0.31**	**1.23**		**39.02**	**2.30**		**3.52**

1. Emission Factor Basis Key
   - A Refer to footnote 1.A for Combustion Turbine - Option A.
   - B Refer to footnote 1.B for Combustion Turbine - Option A.
2. Controlled Potential Emissions - Normal Operation Basis Key
   - C Refer to footnote 2.C for Combustion Turbine - Option A.
   - D Refer to footnote 2.D for Combustion Turbine - Option A.
3. Controlled Potential Emission - SU-SD Basis Key
   - E Refer to footnore 3.E for Combustion Turbine - Option A.
4. Worst-case annual emission rate calculated as the sum of the controlled annual HAP emission rate during normal operation and the controlled annual HAP emission rate during SU-SD events.

Table C-5. Combustion and Steam Turbine Generator Purging Potential GHG Emissions

Turbine Data	EU09, EU10, & Steam Turbine	
Volume CO_2 Required for Purge	10,000	cf per turbine (1 atm, 25°C)
Number of Maintenance Shutdowns[1]	1	shutdown/yr
Ideal Gas Law Constant	0.73	ft^3*atm/(R*lb-mol)
Molar Volume	392	dscf/lb-mol (1 atm, 25°C)
Molecular Weight CO_2	44	lb/lb-mol

	CO_2 Emissions Per Turbine[1,2] (tpy)	CO_2 Emissions Total[3] (tpy)
Turbine Purging	0.56	1.68

1. CO_2 purging occurs only once every 2 to 3 years. It is conservatively assumed that purging occurs once annually for each combustion turbine generator and the steam turbine generator.
2. CO_2 Emissions per Turbine (tpy) Volume CO_2 required for purge (cf) / Molar Volume (dscf/lb-mol) * Number of Maintenance Shutdowns (shutdown/yr) * MW of CO_2 (lb/lb-mol) / 2,000 (lb/ton)
3. CO_2 Emissions Total (tpy) CO_2 Emissions per Turbine (tpy) * (Number of Turbines [3])

Table C-6. Auxiliary Boiler Potential NSR-Regulated Pollutant and GHG Emissions

Auxiliary Boiler	**EU11**	
Maximum Heat Input	99.9	MMBtu/hr (HHV)
Fuel Heat Content	997	MMBtu/MMscf (HHV)
Potential Hours of Operation	8,760	hr/yr

Pollutant	Emission Factor[1,2] (lb/MMBtu)	Potential Emissions (lb/hr)	(tpy)
CO	0.08	7.49	32.82
NO_X	0.04	3.60	15.75
PM	0.01	0.70	3.06
PM_{10}	0.01	0.70	3.06
$PM_{2.5}$	0.01	0.70	3.06
SO_2	3.00E-03	0.30	1.31
VOC	0.01	0.55	2.41
CO_2	116.89	11,677	51,146
N_2O	2.20E-04	0.02	0.10
CH_4	2.20E-03	0.22	0.96

1. Emission factors based on vendor guarantees, except for VOC, which is based on AP-42, Table 1.4-2, and CO_2, N_2O, and CH , which are based on 40 CFR 98, Subpart C, Tables C-1 and C-2.
2. PM_{10} and $PM_{2.5}$ emissions are conservatively assumed to be equal to PM emissions.

Table C-7. Auxiliary Boiler Potential HAP/Toxic Emissions

Pollutant	HAP (Yes/No)	Emission Factor[1] (lb/MMscf)	(lb/MMBtu)	Potential Emissions (lb/hr)	(tpy)
2-Methylnaphthalene	Yes	2.40E-05	2.41E-08	2.40E-06	1.05E-05
3-Methylchloranthrene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
7,12-Dimethylbenz(a)anthrace	Yes	1.60E-05	1.60E-08	1.60E-06	7.02E-06
Acenaphthene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Acenaphthylene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Anthracene	Yes	2.40E-06	2.41E-09	2.40E-07	1.05E-06
Arsenic	Yes	2.00E-04	2.01E-07	2.00E-05	8.77E-05
Barium	No	4.40E-03	4.41E-06	4.41E-04	1.93E-03
Beryllium	Yes	1.20E-05	1.20E-08	1.20E-06	5.26E-06
Benzene	Yes	2.10E-03	2.11E-06	2.10E-04	9.21E-04
Benzo(a)anthracene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Benzo(a)pyrene	Yes	1.20E-06	1.20E-09	1.20E-07	5.26E-07
Benzo(b)fluoranthene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Benzo(g,h,i)perylene	Yes	1.20E-06	1.20E-09	1.20E-07	5.26E-07
Benzo(k)fluoranthene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Butane	No	2.10E+00	2.11E-03	2.10E-01	9.21E-01
Cadmium	Yes	1.10E-03	1.10E-06	1.10E-04	4.83E-04
Chromium	Yes	1.40E-03	1.40E-06	1.40E-04	6.14E-04
Chrysene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Cobalt	Yes	8.40E-05	8.42E-08	8.41E-06	3.69E-05
Copper	No	8.50E-04	8.52E-07	8.51E-05	3.73E-04
Dibenzo(a,h)anthracene	Yes	1.20E-06	1.20E-09	1.20E-07	5.26E-07
Dichlorobenzene	Yes	1.20E-03	1.20E-06	1.20E-04	5.26E-04
Ethane	No	3.10E+00	3.11E-03	3.10E-01	1.36E+00
Fluoranthene	Yes	3.00E-06	3.01E-09	3.00E-07	1.32E-06
Fluorene	Yes	2.80E-06	2.81E-09	2.80E-07	1.23E-06
Formaldehyde	Yes	7.50E-02	7.52E-05	7.51E-03	3.29E-02
Hexane	Yes	1.80E+00	1.80E-03	1.80E-01	7.90E-01
Indeno(1,2,3-cd)pyrene	Yes	1.80E-06	1.80E-09	1.80E-07	7.90E-07
Lead	Yes	5.00E-04	5.01E-07	5.01E-05	2.19E-04
Manganese	Yes	3.80E-04	3.81E-07	3.81E-05	1.67E-04
Mercury	Yes	2.60E-04	2.61E-07	2.60E-05	1.14E-04
Molybdenum	No	1.10E-03	1.10E-06	1.10E-04	4.83E-04
Naphthalene	Yes	6.10E-04	6.12E-07	6.11E-05	2.68E-04
Nickel	Yes	2.10E-03	2.11E-06	2.10E-04	9.21E-04
Pentane	No	2.60E+00	2.61E-03	2.60E-01	1.14E+00
Phenanthrene	Yes	1.70E-05	1.70E-08	1.70E-06	7.46E-06
Propane	No	1.60E+00	1.60E-03	1.60E-01	7.02E-01
Pyrene	Yes	5.00E-06	5.01E-09	5.01E-07	2.19E-06
Selenium	Yes	2.40E-05	2.41E-08	2.40E-06	1.05E-05
Toluene	Yes	3.40E-03	3.41E-06	3.41E-04	1.49E-03
Vanadium	No	2.30E-03	2.31E-06	2.30E-04	1.01E-03
Zinc	No	2.90E-02	2.91E-05	2.90E-03	1.27E-02
Total HAP				**1.89E-01**	**8.28E-01**

1. U.S. EPA. (1998, July). Natural Gas Combustion. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 1.4). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Table C-8. Cooling Tower Potential NSR-Regulated Pollutant Emissions

Cooling Tower	**EU12**	
Capacity	220,000	gpm
Total Dissolved Solids[1]	1,500	mg/L
Drift Loss	0.001	%
Drift Mass Governed by Atmospheric Dispersion[2]	31.30	%
Mass of Particles with Diameter <10 µm	72.59	%
Mass of Particles with Diameter <2.5 µm	0.22	%
Potential Hours of Operation	8,760	hr/yr

Drift Mass Flow Rate[3] (lb/hr)	**Total PM Emission Rate[4,5]**		**Total PM_{10} Emission Rate[5,6]**		**Total $PM_{2.5}$ Emission Rate[5,7]**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
1,101	0.52	2.26	0.38	1.64	1.14E-03	0.01

1. Represents maximum recirculated water TDS, assuming four cycles of concentration.
2. U.S. EPA. (1979, November). *Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1 Technical Report* EPA 600 7-79-251a.
3. Drift mass flow rate (lb/hr) Cooling tower capacity (gpm) * Density of water (8.34 lb/gal) * 60 (min/hour) * Drift loss (%) .
4. Hourly PM emission rate (lb/hr) Drift mass flow rate (lb/hr) * Dispersion Factor (%) * TDS (mg/L)/(1,000,000).
5. Annual PM/PM_{10}/$PM_{2.5}$ emission rate (ton/yr) Hourly emission rate (lb/hr) * 8,760 (hours/yr)/(2000 lb/ton).
6. Hourly PM_{10} emission rate (lb/hr) Hourly PM emission rate (lb/hr) * Mass of Particles with Diameter <10 µm / 100
7. Hourly $PM_{2.5}$ emission rate (lb/hr) Hourly PM emission rate (lb/hr) * Mass of Particles with Diameter <2.5 µm / 100

Table C-9. Cooling Tower Particle Size Distribution[1,2]

EPRI Droplet Diameter[3] (µm)	Droplet Volume (µm^3)	Droplet Mass (µg)	Particle Mass[4] (Solids) (µg)	Solid Particle Volume (µm^3)	Solid Particle Diameter[4] (µm)	EPRI % Mass Smaller[1]
10	5.24E+02	5.24E-04	7.85E-07	3.57E-01	0.880	0
20	4.19E+03	4.19E-03	6.28E-06	2.86E+00	1.760	0.196
28	1.20E+04	1.20E-02	1.80E-05	8.18E+00	2.500	0.221
30	1.41E+04	1.41E-02	2.12E-05	9.64E+00	2.640	0.226
40	3.35E+04	3.35E-02	5.03E-05	2.28E+01	3.521	0.514
50	6.54E+04	6.54E-02	9.82E-05	4.46E+01	4.401	1.816
60	1.13E+05	1.13E-01	1.70E-04	7.71E+01	5.281	5.702
70	1.80E+05	1.80E-01	2.69E-04	1.22E+02	6.161	21.348
90	3.82E+05	3.82E-01	5.73E-04	2.60E+02	7.921	49.812
110	6.97E+05	6.97E-01	1.05E-03	4.75E+02	9.682	70.509
114	7.68E+05	7.68E-01	1.15E-03	5.24E+02	10.000	72.591
130	1.15E+06	1.15E+00	1.73E-03	7.84E+02	11.442	82.023
150	1.77E+06	1.77E+00	2.65E-03	1.20E+03	13.202	88.012
180	3.05E+06	3.05E+00	4.58E-03	2.08E+03	15.843	91.032
210	4.85E+06	4.85E+00	7.27E-03	3.31E+03	18.483	92.468
240	7.24E+06	7.24E+00	1.09E-02	4.94E+03	21.124	94.091
270	1.03E+07	1.03E+01	1.55E-02	7.03E+03	23.764	94.689
300	1.41E+07	1.41E+01	2.12E-02	9.64E+03	26.404	96.288
350	2.24E+07	2.24E+01	3.37E-02	1.53E+04	30.805	97.011
400	3.35E+07	3.35E+01	5.03E-02	2.28E+04	35.206	98.340
450	4.77E+07	4.77E+01	7.16E-02	3.25E+04	39.607	99.071
500	6.54E+07	6.54E+01	9.82E-02	4.46E+04	44.007	99.071
600	1.13E+08	1.13E+02	1.70E-01	7.71E+04	52.809	100

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2. Highlighted rows in the table above indicate interpolated values used to determine PM_{10}/$PM_{2.5}$ speciation.

3. Test data provided by Brentwood Industries for cooling tower with 0.0003 percent drift rate. The use of this data is conservative as it can be reasonably expected that a cooling tower with a 0.0003 percent drift rate will produce smaller droplets than one with a 0.001 percent drift rate.

4. Particle Masses and Solid Particle Diameters calculated based on a TDS value of 1,500 mg/L (assumed equivalent to ppmw).

Table C-10. Emergency Generator Potential NSR-Regulated Pollutant and GHG Emissions

Emergency Generator	**EU13**	
Engine Power	1,006	bhp
Potential Hours of Operation[1]	500	hr/yr
Heating Value of Diesel	19,170	Btu/lb
Maximum Fuel Consumption	56.63	gal/hr
Density of Diesel	7.00	lb/gal
Heat Input	7.60	MMBtu/hr, input
Power Conversion[2]	7,555	Btu/hp-hr

Pollutant	Emission Factor[3,4,5,6]	Units	Potential Emissions (lb/hr)	(tpy)
CO	0.25	g/hp-hr	0.55	0.14
NO_X	5.25	g/hp-hr	11.64	2.91
PM	0.02	g/hp-hr	0.05	0.01
PM_{10}	0.02	g/hp-hr	0.05	0.01
$PM_{2.5}$	0.02	g/hp-hr	0.05	0.01
SO_2	15.00	ppmw S	0.01	2.97E-03
VOC (NMHC)	3.00E-02	g/hp-hr	0.07	0.02
CO_2	163	lb/MMBtu	1,239	310
N_2O	1.32E-03	lb/MMBtu	0.01	2.51E-03
CH_4	0.01	lb/MMBtu	0.05	0.01

1. Potential hours of operation assumed to be 500 hr/yr for emission calculation purposes.
2. Conversion factor calculated based on heat input and engine power ratings.
3. Criteria emissions factors provided by engine vendor, except as otherwise noted.
4. Sulfur content per 40 CFR 80.510(b) standard, as required by NSPS IIII.
5. CO_2, N_2O, and CH emission factors per 40 CFR 98, Subpart C, Tables C-1 and C-2.
6. Emissions data from manufacturer is based on 100 percent load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

Table C-11. Emergency Generator Potential HAP/Toxic Emissions

Pollutant	HAP (Yes/No)	Emission Factor[1] (lb/MMBtu)	Potential Emissions (lb/hr)	(tpy)
Acenaphthene	Yes	4.68E-06	3.56E-05	8.89E-06
Acenaphthylene	Yes	9.23E-06	7.01E-05	1.75E-05
Acetaldehyde	Yes	2.52E-05	1.92E-04	4.79E-05
Acrolein	Yes	7.88E-06	5.99E-05	1.50E-05
Anthracene	Yes	1.23E-06	9.35E-06	2.34E-06
Benzene	Yes	7.76E-04	5.90E-03	1.47E-03
Benzo(a)anthracene	Yes	6.22E-07	4.73E-06	1.18E-06
Benzo(a)pyrene	Yes	2.57E-07	1.95E-06	4.88E-07
Benzo(b)fluoranthene	Yes	1.11E-06	8.44E-06	2.11E-06
Benzo(g,h,i)perylene	Yes	5.56E-07	4.23E-06	1.06E-06
Benzo(k)fluoranthene	Yes	2.18E-07	1.66E-06	4.14E-07
Chrysene	Yes	1.53E-06	1.16E-05	2.91E-06
Dibenzo(a,h)anthracene	Yes	3.46E-07	2.63E-06	6.57E-07
Fluoranthene	Yes	4.03E-06	3.06E-05	7.66E-06
Fluorene	Yes	1.28E-05	9.73E-05	2.43E-05
Formaldehyde	Yes	7.89E-05	6.00E-04	1.50E-04
Indeno(1,2,3-cd)pyrene	Yes	4.14E-07	3.15E-06	7.87E-07
Naphthalene	Yes	1.30E-04	9.88E-04	2.47E-04
Phenanthrene	Yes	4.08E-05	3.10E-04	7.75E-05
Propylene	No	2.79E-03	2.12E-02	5.30E-03
Pyrene	Yes	3.71E-06	2.82E-05	7.05E-06
Toluene	Yes	2.81E-04	2.14E-03	5.34E-04
Xylene (Total)	Yes	1.93E-04	1.47E-03	3.67E-04
Total HAP			**1.20E-02**	**2.99E-03**

1. U.S. EPA. (1996, October). Large Stationary Diesel and All Stationary Dual-fuel Engines. In*AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.4). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf

Table C-12. Fire Pump Engine Potential NSR-Regulated Pollutant and GHG Emissions

Fire Pump Engine	**EU14**	
Engine Power	542	bhp
Potential Hours of Operation[1]	500	hr/yr
Heating Value of Diesel	19,170	Btu/lb
Maximum Fuel Consumption	26.50	gal/hr
Density of Diesel Fuel	7.00	lb/gal
Heat Input	3.56	MMBtu/hr, input
Power Conversion[2]	6,562	Btu/hp-hr

Pollutant	Emission Factor[3,4 5]	Units	Potential Emissions (lb/hr)	(tpy)
CO	0.67	g/bhp-hr	0.80	0.20
NO_X	2.57	g/bhp-hr	3.06	0.77
PM	0.08	g/bhp-hr	0.09	0.02
PM_{10}	0.08	g/bhp-hr	0.09	0.02
$PM_{2.5}$	0.08	g/bhp-hr	0.09	0.02
SO_2	15	ppmw S	0.01	1.39E-03
VOC (NMHC)	0.09	g/bhp-hr	0.10	0.03
CO_2	163	lb/MMBtu	580	145
N_2O	1.32E-03	lb/MMBtu	0.00	1.18E-03
CH_4	0.01	lb/MMBtu	0.02	0.01

1. Potential hours of operation assumed to be 500 hr/yr for emission calculation purposes.
2. Conversion factor calculated based on heat input and engine power rating.
3. Criteria emissions factors provided by engine vendor, except as otherwise noted.
4. Sulfur content per 40 CFR 80.510(b) standard, as required by NSPS IIII.
5. CO_2, N_2O, and CH emission factors per 40 CFR 98, Subpart C, Tables C-1 and C-2.

Table C-13. Fire Pump Engine Potential HAP/Toxic Emissions

Pollutant	HAP (Yes/No)	Emission Factor[1] (lb/MMBtu)	Potential Emissions (lb/hr)	(tpy)
1,3-Butadiene	Yes	3.91E-05	1.39E-04	3.48E-05
Acenaphthene	Yes	1.42E-06	5.05E-06	1.26E-06
Acenaphthylene	Yes	5.06E-06	1.80E-05	4.50E-06
Acetaldehyde	Yes	7.67E-04	2.73E-03	6.82E-04
Acrolein	Yes	9.25E-05	3.29E-04	8.22E-05
Anthracene	Yes	1.87E-06	6.65E-06	1.66E-06
Benzene	Yes	9.33E-04	3.32E-03	8.30E-04
Benzo(a)anthracene	Yes	1.68E-06	5.97E-06	1.49E-06
Benzo(a)pyrene	Yes	1.88E-07	6.69E-07	1.67E-07
Benzo(b)fluoranthene	Yes	9.91E-08	3.52E-07	8.81E-08
Benzo(g,h,i)perylene	Yes	4.89E-07	1.74E-06	4.35E-07
Benzo(k)fluoranthene	Yes	1.55E-07	5.51E-07	1.38E-07
Chrysene	Yes	3.53E-07	1.26E-06	3.14E-07
Dibenzo(a,h)anthracene	Yes	5.83E-07	2.07E-06	5.18E-07
Fluoranthene	Yes	7.61E-06	2.71E-05	6.77E-06
Fluorene	Yes	2.92E-05	1.04E-04	2.60E-05
Formaldehyde	Yes	1.18E-03	4.20E-03	1.05E-03
Indeno(1,2,3-cd)pyrene	Yes	3.75E-07	1.33E-06	3.33E-07
Naphthalene	Yes	8.48E-05	3.02E-04	7.54E-05
Phenanthrene	Yes	2.94E-05	1.05E-04	2.61E-05
Propylene	No	2.58E-03	9.18E-03	2.29E-03
Pyrene	Yes	4.78E-06	1.70E-05	4.25E-06
Toluene	Yes	4.09E-04	1.45E-03	3.64E-04
Xylene (Total)	Yes	2.85E-04	1.01E-03	2.53E-04
Total HAP			**1.38E-02**	**3.44E-03**

1. U.S. EPA. (1996, October). Gasoline and Diesel Industrial Engines. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 3.3). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s03.pdf

Table C-14. Fuel Gas Heater Potential NSR-Regulated Pollutant and GHG Emissions

Fuel Gas Heater	**EU15**	
Maximum Heat Input	15.0	MMBtu/hr (HHV)
Fuel Heat Content	997	MMBtu/MMscf (HHV)
Potential Hours of Operation	8,760	hr/yr

Pollutant	**Emission Factor[1,2] (lb/MMBtu)**	**Potential Emissions (lb/hr)**	**(tpy)**
CO	0.08	1.26	5.53
NO_X	0.06	0.90	3.94
PM	0.01	0.11	0.46
PM_{10}	0.01	0.11	0.46
$PM_{2.5}$	0.01	0.11	0.46
SO_2	3.00E-03	0.05	0.20
VOC	0.01	0.08	0.36
CO_2	116.89	1,753	7,680
N_2O	2.20E-04	3.31E-03	0.01
CH_4	2.20E-03	0.03	0.14

1. Factors based on vendor guarantees, except for CO and VOC, which are based on AP-42, Tables 1.4-1 and 1.4-2, respectively, and CO_2, N_2O, and CH , which are based on 40 CFR 98, Subpart C, Tables C-1 and C-2.
2. PM10 and PM2.5 are assumed to be equal to PM.

Table C-15. Fuel Gas Heater Potential HAP/Toxic Emissions

Pollutant	HAP (Yes/No)	Emission Factor[1] (lb/MMscf)	Emission Factor[1] (lb/MMBtu)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
2-Methylnaphthalene	Yes	2.40E-05	2.41E-08	3.61E-07	1.58E-06
3-Methylchloranthrene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
7,12-Dimethylbenz(a)anthrace	Yes	1.60E-05	1.60E-08	2.41E-07	1.05E-06
Acenaphthene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Acenaphthylene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Anthracene	Yes	2.40E-06	2.41E-09	3.61E-08	1.58E-07
Arsenic	Yes	2.00E-04	2.01E-07	3.01E-06	1.32E-05
Barium	No	4.40E-03	4.41E-06	6.62E-05	2.90E-04
Beryllium	Yes	1.20E-05	1.20E-08	1.80E-07	7.90E-07
Benzene	Yes	2.10E-03	2.11E-06	3.16E-05	1.38E-04
Benzo(a)anthracene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Benzo(a)pyrene	Yes	1.20E-06	1.20E-09	1.80E-08	7.90E-08
Benzo(b)fluoranthene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Benzo(g,h,i)perylene	Yes	1.20E-06	1.20E-09	1.80E-08	7.90E-08
Benzo(k)fluoranthene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Butane	No	2.10E+00	2.11E-03	3.16E-02	1.38E-01
Cadmium	Yes	1.10E-03	1.10E-06	1.65E-05	7.25E-05
Chromium	Yes	1.40E-03	1.40E-06	2.11E-05	9.22E-05
Chrysene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Cobalt	Yes	8.40E-05	8.42E-08	1.26E-06	5.53E-06
Copper	No	8.50E-04	8.52E-07	1.28E-05	5.60E-05
Dibenzo(a,h)anthracene	Yes	1.20E-06	1.20E-09	1.80E-08	7.90E-08
Dichlorobenzene	Yes	1.20E-03	1.20E-06	1.80E-05	7.90E-05
Ethane	No	3.10E+00	3.11E-03	4.66E-02	2.04E-01
Fluoranthene	Yes	3.00E-06	3.01E-09	4.51E-08	1.98E-07
Fluorene	Yes	2.80E-06	2.81E-09	4.21E-08	1.84E-07
Formaldehyde	Yes	7.50E-02	7.52E-05	1.13E-03	4.94E-03
Hexane	Yes	1.80E+00	1.80E-03	2.71E-02	1.19E-01
Indeno(1,2,3-cd)pyrene	Yes	1.80E-06	1.80E-09	2.71E-08	1.19E-07
Lead	Yes	5.00E-04	5.01E-07	7.52E-06	3.29E-05
Manganese	Yes	3.80E-04	3.81E-07	5.71E-06	2.50E-05
Mercury	Yes	2.60E-04	2.61E-07	3.91E-06	1.71E-05
Molybdenum	No	1.10E-03	1.10E-06	1.65E-05	7.25E-05
Naphthalene	Yes	6.10E-04	6.12E-07	9.17E-06	4.02E-05
Nickel	Yes	2.10E-03	2.11E-06	3.16E-05	1.38E-04
Pentane	No	2.60E+00	2.61E-03	3.91E-02	1.71E-01
Phenanthrene	Yes	1.70E-05	1.70E-08	2.56E-07	1.12E-06
Propane	No	1.60E+00	1.60E-03	2.41E-02	1.05E-01
Pyrene	Yes	5.00E-06	5.01E-09	7.52E-08	3.29E-07
Selenium	Yes	2.40E-05	2.41E-08	3.61E-07	1.58E-06
Toluene	Yes	3.40E-03	3.41E-06	5.11E-05	2.24E-04
Vanadium	No	2.30E-03	2.31E-06	3.46E-05	1.52E-04
Zinc	No	2.90E-02	2.91E-05	4.36E-04	1.91E-03
Total HAP				**2.84E-02**	**1.24E-01**

1. U.S. EPA. (1998, July). Natural Gas Combustion. In *AP-42 Compilation of Air Pollutant Emission Factors* (Section 1.4). Retrieved from http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Table C-16. Storage Tanks Potential NSR-Regulated Pollutant Emissions

EUID	Description	Volume (gal)	Maximum Throughput[1] (gal/yr)	Annual Turnovers	VOC Emissions[2] (lb/yr)	VOC Emissions[2] (tpy)	Toluene Emissions[2] (lb/yr)	Toluene Emissions[2] (tpy)	Xylenes Emissions[2] (lb/yr)	Xylenes Emissions[2] (tpy)
Insig.	Diesel Tank #6 (660 gal)	660	28,314	42.90	0.56	2.80E-04	0.01	5.00E-06	0.03	1.50E-05
Insig.	Diesel Tank #7 (849 gal)	849	13,250	15.61	0.39	1.95E-04	0.01	5.00E-06	0.02	1.00E-05
Insig.	Lube Oil Tank #1 (8,400 gal)	8,400	88	0.01	6.81	3.41E-03	-	-	-	-
Insig.	Lube Oil Tank #2 (8,400 gal)	8,400	88	0.01	6.81	3.41E-03	-	-	-	-
Insig.	Lube Oil Tank #3 (12,050 gal)	12,050	88	0.01	9.75	4.88E-03	-	-	-	-

1. Maximum throughputs for Diesel Tanks #6 and #7 are based on the maximum annual fuel consumption for the new emergency generator and fire pump, respectively. Maximum throughputs for Lube Oil Tanks #1, #2, and #3 are each based on the maximum lube oil demister vent emission rate. Lube oil is recirculated through the turbines' internal storage and distribution system, and apart from losses due to emissions from the demister vents, the level of lube oil in each tank remains constant.

2. Emissions calculated using U.S. EPA's TANKS 4.0.9d.

Table C-17. Lube Oil Demister Vents Potential NSR-Regulated Pollutant Emissions

Lube Oil Demister Vents	**Insig.**	
Lube Oil Density	7.17	lb/gal
Number of Turbines (CT + ST)	3	
Potential Hours of Operation	8,760	hr/yr

Pollutant	Potential Fugitive Emissions (Per Turbine)[1 2]			Potential Fugitive (Total)[2]	
	(gal/hr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
$PM/PM_{10}/PM_{2.5}$	0.01	0.07	0.31	0.22	0.94
VOC	0.01	0.07	0.31	0.22	0.94

1. Emission rate in gal/hr estimated by turbine vendor.
2. It is conservatively assumed that all lube oil emitted from the demister vents is $PM/PM_{10}/PM_{2.5}$.

Table C-18. Circuit Breaker Potential GHG Emissions

Circuit Breakers
SF_6 Leak Rate[1] 0.50 %/yr

Description	Number of Circuit Breakers	Amount of SF_6 per Breaker (lb)	SF_6 Emission Rate[2] (tpy)	CO_2e[3,4] (tpy)
Generator Braker	3	24.25	1.82E-04	4.15
Switchyard Breaker	12	230.00	6.90E-03	157.32
Total Circuit Breaker Emissions:			0.01	161.47

1. Proposed BACT Limit
2. Calculated according to the following equation:
SF_6 Emission Rate (tpy) Number of Circuit Breakers * Amount of SF_6 per Breaker (lb) *
SF_6 Leak Rate (%/yr) / 100 * 2,000 (lb/ton)
3. Calculated according to the following equation:
CO_2e (tpy) SF_6 Emission Rate (tpy) * Global Warming Potential for SF_6
4. Emissions in CO_2e calculated based on a Global Warming Potential of 22,800 for SF_6, per 40 CFR 98, Table A-1 (78 FR 71904. [2013, November 29].).

Table C-19. Fugitive Components Potential GHG Emissions

Fugitive Components
Potential Hours of Operation 8,760

Components	Component Count[1]	Emission Factors[2] (kg/hr-component)	Emission Factors[2] (lb/hr-component)	CH_4 Emissions[3,4] (tpy)	CO_2e Emissions[5,6] (tpy)
Valves	410	4.50E-03	9.92E-03	17.82	445.39
Pressure Relief Valves	30	8.80E-03	1.94E-02	2.55	63.73
Flanges/Connectors	690	3.90E-04	8.60E-04	2.60	64.96
Compressors	2	8.80E-03	1.94E-02	0.17	4.25
Open-ended Lines	60	2.00E-03	4.41E-03	1.16	28.97
Other	11	8.80E-03	1.94E-02	0.93	23.37
				Total Emissions	**630.67**

1. Estimated component counts, including 20 percent safety factor for flanges/connectors and 10 percent safety factor for valves, pressure relief valves, and open-ended lines.
2. U.S. EPA. (1995, November). *Protocol for Equipment Leak Emission Estimates.* Table 2-4, Oil and Gas Production Operations Average Emission Factors.
3. Emissions calculated according to the following equation:
 Annual Emission Rate (tpy) Component Count * Emission Factor (lb/hr-component) * Methane Content (%) * 8,760 (hr/yr) / 2,000 (lb/ton)
4. Methane content of gas conservatively assumed to be 100 percent.
5. Emissions calculated according to the following equation:
 CO_2e (tpy) CH Emissions (tpy) * Global Warming Potential for CH
6. Emissions in CO_2e calculated based on a Global Warming Potential of 25 for CH , per 40 CFR 98, Table A-1 (78 FR 71904. [2013, November 29].).

Table C-20. Baseline Emissions for Boiler #4

Month-Year	Baseline Period Monthly Emissions (tons)											
	SO_2[1]	NO_X[1]	PM[2]	PM_{10}[3]	$PM_{2.5}$[3]	VOC[4]	CO[4]	SAM[5]	Lead[4]	CO_2[1]	N_2O[6]	CH_4[6]
November-11	480.5	51.1	18.6	39.4	32.4	0.3	2.4	5.9	0.002	25,289	0.4	3.0
December-11	397.2	46.6	16.1	34.2	28.1	0.3	2.1	4.9	0.002	21,820	0.4	2.6
January-12	661.4	71.1	25.1	53.1	43.6	0.5	4.2	8.2	0.004	33,862	0.6	4.0
February-12	529.5	61.6	20.8	43.2	35.4	0.4	3.4	6.6	0.003	28,057	0.5	3.3
March-12	691.9	80.3	27.5	56.4	46.0	0.5	4.1	8.6	0.003	37,064	0.6	4.4
April-12	694.6	81.5	29.0	58.7	47.7	0.5	4.0	8.6	0.003	39,109	0.7	4.6
May-12	677.1	80.9	28.5	57.0	46.2	0.5	3.9	8.4	0.003	38,456	0.7	4.5
June-12	674.1	75.9	27.7	55.4	44.9	0.5	4.3	8.3	0.004	37,376	0.6	4.4
July-12	841.1	97.2	33.3	65.5	52.9	0.6	5.1	10.4	0.004	44,908	0.8	5.3
August-12	718.5	76.1	27.3	54.8	44.4	0.5	3.9	8.9	0.003	36,828	0.6	4.3
September-12	378.5	39.9	14.1	28.5	23.1	0.2	2.0	4.7	0.002	19,061	0.3	2.3
October-12	41.8	4.5	0.0	0.0	0.0	0.0	0.0	0.5	0.000	2,200	0.0	0.0
November-12	195.7	21.0	7.7	15.6	12.6	0.1	1.0	2.4	0.001	10,479	0.2	1.2
December-12	709.4	77.0	27.8	56.6	46.1	0.5	4.0	8.8	0.003	37,544	0.6	4.4
January-13	793.9	86.6	7.2	46.2	43.5	0.5	4.3	9.8	0.004	40,837	0.7	4.8
February-13	458.0	50.3	4.1	26.5	24.9	0.3	2.2	5.7	0.002	23,259	0.4	2.7
March-13	573.1	63.0	5.2	34.2	32.2	0.4	3.1	7.1	0.003	29,680	0.5	3.5
April-13	903.2	98.6	7.6	50.3	47.4	0.5	4.5	11.2	0.004	46,503	0.7	5.1
May-13	832.2	91.2	7.4	49.0	46.2	0.5	4.4	10.3	0.004	43,567	0.7	5.0
June-13	613.1	72.9	5.8	36.9	34.7	0.4	3.4	7.6	0.003	34,477	0.6	3.9
July-13	824.8	95.7	7.7	49.2	46.2	0.6	4.6	10.2	0.004	45,822	0.8	5.2
August-13	365.4	46.5	3.5	21.9	20.6	0.2	2.1	4.5	0.002	21,850	0.3	2.3
September-13	570.5	70.1	5.2	32.8	30.8	0.4	3.1	7.1	0.003	32,239	0.5	3.5
October-13	595.0	74.0	5.5	34.5	32.4	0.4	3.3	7.4	0.003	33,190	0.5	3.7
24-Month Rolling Average (tons/yr)	7,110.3	806.8	181.4	500.0	431.0	4.8	39.8	88.0	0.033	381,739	6.4	44.1

1. SO_2, NO_X, and CO_2 emissions tracked via CEMS data.
2. Pollutant emissions from coal combustion based on emission factors developed from previous stack testing data. Pollutant emissions from fuel oil combustion based on AP-42 Table 1.3-1. PM emissions include filterable particulate only.
3. Pollutant emissions from coal combustion based on emission factors developed from previous PM stack testing data (filterable) and AP-42 Table 1.1-5 (condensable). Pollutant emissions from fuel oil combustion based on AP-42 Table 1.3-1 (filterable) and AP-42 Table 1.3-2 (condensable). Particle size distribution data from AP-42 Table 1.1-6 is applied to filterable PM emissions from coal combustion to obtain filterable PM_{10} and $PM_{2.5}$ fractions. Particle size distribution data from AP-42 Table 1.3-4 is applied to filterable PM emissions from fuel oil combustion to obtain filterable PM_{10} and $PM_{2.5}$ fractions.
4. Pollutant emissions from coal combustion based on emission factors for Bituminous Coal in AP-42 Table 1.1-19 (VOC), Table 1.1-3 (CO), and Table 1.1-18 (Lead). Pollutant emissions from fuel oil combustion based on emission factors for distillate oil in AP-42 Table 1.3-3 (VOC), Table 1.3-1 (CO), and Table 1.3-10 (Lead).
5. SAM emissions calculated assuming 1 percent of SO_2 produced during combustion forms SO_3. virtually 100 percent of SO_3 combines with water vapor in the flue gas to form SAM, and 90 percent control of SAM is provided by the wet ESP.
6. N_2O and CH_4 emissions calculated based coal and petroleum combustion emission factors from 40 CFR 98, Subpart C, Table C-2.

Table C-21. Baseline Emissions for Boiler #5

Month-Year	Baseline Period Monthly Emissions (tons)											
	SO_2[1]	NO_X[1]	PM[2]	PM_{10}[3]	$PM_{2.5}$[3]	VOC[4]	CO[4]	SAM[5]	Lead[4]	CO_2[1]	N_2O[6]	CH_4[6]
November-11	357.1	36.3	9.1	26.2	22.8	0.3	2.8	4.4	0.002	18,871	0.3	2.2
December-11	823.2	86.2	21.0	60.4	52.4	0.6	5.2	10.2	0.004	43,191	0.7	5.1
January-12	1,177.5	117.7	28.4	81.7	70.9	0.9	7.8	14.6	0.007	58,472	1.0	6.9
February-12	1,172.3	123.3	28.7	81.0	70.1	0.9	7.8	14.5	0.007	58,982	1.0	7.0
March-12	1,058.1	111.5	26.7	74.1	64.0	0.8	6.7	13.1	0.006	54,793	0.9	6.5
April-12	937.6	102.1	25.2	68.8	59.3	0.7	5.9	11.6	0.005	51,781	0.9	6.1
May-12	877.3	94.5	23.9	64.4	55.3	0.7	5.5	10.9	0.005	49,149	0.8	5.8
June-12	1,039.8	114.5	27.5	74.2	63.8	0.9	7.5	12.9	0.006	56,576	1.0	6.7
July-12	1,160.6	129.0	30.7	81.2	69.6	1.0	8.0	14.4	0.007	63,025	1.1	7.4
August-12	1,089.7	117.1	28.0	75.8	65.2	0.8	6.5	13.5	0.005	57,593	1.0	6.8
September-12	1,072.7	113.3	27.3	74.4	64.0	0.8	6.4	13.3	0.005	56,168	1.0	6.6
October-12	682.7	72.3	17.5	47.3	40.7	0.5	4.2	8.4	0.003	36,107	0.6	4.2
November-12	891.8	92.3	22.5	61.3	52.7	0.6	5.3	11.0	0.004	46,434	0.8	5.5
December-12	1,016.1	111.9	26.2	72.0	62.0	0.8	6.3	12.6	0.005	53,819	0.9	6.3
January-13	1,049.3	109.6	19.0	66.9	59.7	0.8	6.4	13.0	0.005	53,467	0.9	6.3
February-13	974.9	104.6	17.4	61.7	55.1	0.7	6.0	12.1	0.005	48,934	0.8	5.8
March-13	1,092.9	123.6	19.5	69.9	62.5	0.8	6.5	13.5	0.005	54,946	0.9	6.5
April-13	447.3	43.5	9.0	32.3	28.9	0.3	2.7	5.5	0.002	21,924	0.4	3.0
May-13	1,153.3	123.7	24.9	89.5	80.0	0.9	7.3	14.3	0.006	60,816	1.2	8.3
June-13	1,002.5	110.1	22.9	80.0	71.3	0.8	6.7	12.4	0.006	54,657	1.1	7.6
July-13	1,020.1	109.8	23.5	81.8	72.8	0.8	6.9	12.6	0.006	55,274	1.1	7.8
August-13	1,017.8	118.3	24.0	83.0	73.9	0.8	7.1	12.6	0.006	57,762	1.2	8.0
September-13	908.7	107.6	20.0	68.7	61.1	0.7	5.9	11.2	0.005	50,932	1.0	6.7
October-13	1,228.0	145.0	26.5	91.1	81.0	0.9	7.7	15.2	0.007	66,076	1.3	8.8
24-Month Rolling Average (tons/yr)	11,625.7	1,258.9	274.7	833.9	729.5	8.9	74.6	143.9	0.062	614,874	11.0	75.9

1. SO_2, NO_X, and CO_2 emissions tracked via CEMS data.
2. Pollutant emissions from coal combustion based on emission factors developed from previous stack testing data. Pollutant emissions from fuel oil combustion based on AP-42 Table 1.3-1. PM emissions include filterable particulate only.
3. Pollutant emissions from coal combustion based on emission factors developed from previous PM stack testing data (filterable) and AP-42 Table 1.1-5 (condensable). Pollutant emissions from fuel oil combustion based on AP-42 Table 1.3-1 (filterable) and AP-42 Table 1.3-2 (condensable). Particle size distribution data from AP-42 Table 1.1-6 is applied to filterable PM emissions from coal combustion to obtain filterable PM_{10} and $PM_{2.5}$ fractions. Particle size distribution data from AP-42 Table 1.3-4 is applied to filterable PM emissions from fuel oil combustion to obtain filterable PM_{10} and $PM_{2.5}$ fractions.
4. Pollutant emissions from coal combustion based on emission factors for Bituminous Coal in AP-42 Table 1.1-19 (VOC), Table 1.1-3 (CO), and Table 1.1-18 (Lead). Pollutant emissions from fuel oil combustion based on emission factors for distillate oil in AP-42 Table 1.3-3 (VOC), Table 1.3-1 (CO), and Table 1.3-10 (Lead).
5. SAM emissions calculated assuming 1 percent of SO_2 produced during combustion forms SO_3. virtually 100 percent of SO_3 combines with water vapor in the flue gas to form SAM, and 90 percent control of SAM is provided by the wet ESP.
6. N_2O and CH_4 emissions calculated based coal and petroleum combustion emission factors from 40 CFR 98, Subpart C, Table C-2.

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Diesel Tank #6
City:	Central City
State:	Kentucky
Company:	KU
Type of Tank:	Horizontal Tank
Description:	Diesel Tank #6

Tank Dimensions

Shell Length (ft):		5.00
Diameter (ft):		4.74
Volume (gallons):		660.00
Turnovers:		42.90
Net Throughput(gal/yr):		28,314.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Evansville, Indiana (Avg Atmospheric Pressure = 14.56 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Diesel Tank #6 - Horizontal Tank
Central City, Kentucky

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	57.53	52.15	62.91	55.74	0.0060	0.0049	0.0072	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
1,2,4-Trimethylbenzene						0.0185	0.0148	0.0229	120.1900	0.0100	0.0445	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.0901	0.9355	1.2653	78.1100	0.0000	0.0021	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Ethylbenzene						0.0995	0.0821	0.1200	106.1700	0.0001	0.0031	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						1.7936	1.5540	2.0628	86.1700	0.0000	0.0004	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Toluene						0.3056	0.2573	0.3612	92.1300	0.0003	0.0235	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						0.0052	0.0047	0.0049	134.4280	0.9866	0.8684	189.60	
Xylene (-m)						0.0828	0.0682	0.1000	106.1700	0.0029	0.0578	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Diesel Tank #6 - Horizontal Tank
Central City, Kentucky

Annual Emission Calcaulations	
Standing Losses (lb):	0.1086
Vapor Space Volume (cu ft):	56.1975
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.0376
Vented Vapor Saturation Factor:	0.9992
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	56.1975
Tank Diameter (ft):	4.7400
Effective Diameter (ft):	5.4946
Vapor Space Outage (ft):	2.3700
Tank Shell Length (ft):	5.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001

Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0060
Daily Avg. Liquid Surface Temp. (deg. R):	517.1990
Daily Average Ambient Temp. (deg. F):	55.7250
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	515.4150
Tank Paint Solar Absorptance (Shell):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,334.9400
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0376
Daily Vapor Temperature Range (deg. R):	21.5223
Daily Vapor Pressure Range (psia):	0.0023
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0060
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0049
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0072
Daily Avg. Liquid Surface Temp. (deg R):	517.1990
Daily Min. Liquid Surface Temp. (deg R):	511.8184
Daily Max. Liquid Surface Temp. (deg R):	522.5796
Daily Ambient Temp. Range (deg. R):	21.0667
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9992
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0060
Vapor Space Outage (ft):	2.3700
Working Losses (lb):	0.4558
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0060
Annual Net Throughput (gal/yr.):	28,314.0000
Annual Turnovers:	42.9000
Turnover Factor:	0.8660
Tank Diameter (ft):	4.7400
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.5643

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Diesel Tank #6 - Horizontal Tank
Central City, Kentucky

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.46	0.11	0.56
Hexane (-n)	0.00	0.00	0.00
Benzene	0.00	0.00	0.00
Toluene	0.01	0.00	0.01
Ethylbenzene	0.00	0.00	0.00
Xylene (-m)	0.03	0.01	0.03
1,2,4-Trimethylbenzene	0.02	0.00	0.03
Unidentified Components	0.40	0.09	0.49

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Diesel Tank #7
City:	Central City
State:	Kentucky
Company:	KU
Type of Tank:	Horizontal Tank
Description:	Diesel Tank #7

Tank Dimensions

Shell Length (ft):	5.00
Diameter (ft):	5.38

Volume (gallons):		849.00
Turnovers:		15.61
Net Throughput(gal/yr):		13,250.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Evansville, Indiana (Avg Atmospheric Pressure = 14.56 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Diesel Tank #7 - Horizontal Tank
Central City, Kentucky

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	57.53	52.15	62.91	55.74	0.0060	0.0049	0.0072	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
1,2,4-Trimethylbenzene						0.0185	0.0148	0.0229	120.1900	0.0100	0.0445	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.0901	0.9355	1.2653	78.1100	0.0000	0.0021	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Ethylbenzene						0.0995	0.0821	0.1200	106.1700	0.0001	0.0031	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						1.7936	1.5540	2.0628	86.1700	0.0000	0.0004	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Toluene						0.3056	0.2573	0.3612	92.1300	0.0003	0.0235	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						0.0052	0.0047	0.0049	134.4280	0.9866	0.8684	189.60	
Xylene (-m)						0.0828	0.0682	0.1000	106.1700	0.0029	0.0578	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Diesel Tank #7 - Horizontal Tank
Central City, Kentucky

Annual Emission Calcaulations	
Standing Losses (lb):	0.1398
Vapor Space Volume (cu ft):	72.3977
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.0376
Vented Vapor Saturation Factor:	0.9991
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	72.3977
Tank Diameter (ft):	5.3800
Effective Diameter (ft):	5.8538
Vapor Space Outage (ft):	2.6900
Tank Shell Length (ft):	5.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0060
Daily Avg. Liquid Surface Temp. (deg. R):	517.1990
Daily Average Ambient Temp. (deg. F):	55.7250
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	515.4150
Tank Paint Solar Absorptance (Shell):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,334.9400
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0376
Daily Vapor Temperature Range (deg. R):	21.5223
Daily Vapor Pressure Range (psia):	0.0023
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0060
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0049
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0072
Daily Avg. Liquid Surface Temp. (deg R):	517.1990
Daily Min. Liquid Surface Temp. (deg R):	511.8184

Daily Max. Liquid Surface Temp. (deg R):	522.5796
Daily Ambient Temp. Range (deg. R):	21.0667
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9991
Vapor Pressure at Daily Average Liquid:	
Surface Temperature (psia):	0.0060
Vapor Space Outage (ft):	2.6900
Working Losses (lb):	0.2463
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid	
Surface Temperature (psia):	0.0060
Annual Net Throughput (gal/yr.):	13,250.0000
Annual Turnovers:	15.6100
Turnover Factor:	1.0000
Tank Diameter (ft):	5.3800
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.3861

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Diesel Tank #7 - Horizontal Tank
Central City, Kentucky

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.25	0.14	0.39
Hexane (-n)	0.00	0.00	0.00
Benzene	0.00	0.00	0.00
Toluene	0.01	0.00	0.01
Ethylbenzene	0.00	0.00	0.00
Xylene (-m)	0.01	0.01	0.02
1,2,4-Trimethylbenzene	0.01	0.01	0.02
Unidentified Components	0.21	0.12	0.34

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Lube Oil Tank #1 & #2 (Each)
City:	Central City
State:	Kentucky
Company:	KU
Type of Tank:	Horizontal Tank
Description:	Lube Oil Tank #1 & #2 (Each)

Tank Dimensions

Shell Length (ft):	15.00
Diameter (ft):	9.76
Volume (gallons):	8,400.00
Turnovers:	0.01
Net Throughput(gal/yr):	88.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Evansville, Indiana (Avg Atmospheric Pressure = 14.56 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Lube Oil Tank #1 & #2 (Each) - Horizontal Tank
Central City, Kentucky

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Aliphatics (Mineral Spirits)	All	57.53	52.15	62.91	55.74	0.0240	0.0244	0.0236	162.0000			162.00	Option 2: A=-.5143, B=-165.5177, C=257.923

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Lube Oil Tank #1 & #2 (Each) - Horizontal Tank
Central City, Kentucky

Annual Emission Calcaulations	
Standing Losses (lb):	6.8021
Vapor Space Volume (cu ft):	714.7944
Vapor Density (lb/cu ft):	0.0007
Vapor Space Expansion Factor:	0.0374
Vented Vapor Saturation Factor:	0.9938
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	714.7944
Tank Diameter (ft):	9.7600
Effective Diameter (ft):	13.6564
Vapor Space Outage (ft):	4.8800
Tank Shell Length (ft):	15.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0007
Vapor Molecular Weight (lb/lb-mole):	162.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Daily Avg. Liquid Surface Temp. (deg. R):	517.1990
Daily Average Ambient Temp. (deg. F):	55.7250
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	515.4150
Tank Paint Solar Absorptance (Shell):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,334.9400
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0374
Daily Vapor Temperature Range (deg. R):	21.5223
Daily Vapor Pressure Range (psia):	-0.0007
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0244
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0236
Daily Avg. Liquid Surface Temp. (deg R):	517.1990
Daily Min. Liquid Surface Temp. (deg R):	511.8184
Daily Max. Liquid Surface Temp. (deg R):	522.5796
Daily Ambient Temp. Range (deg. R):	21.0667
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9938
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0240
Vapor Space Outage (ft):	4.8800
Working Losses (lb):	0.0081
Vapor Molecular Weight (lb/lb-mole):	162.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Annual Net Throughput (gal/yr.):	88.0000
Annual Turnovers:	0.0105
Turnover Factor:	1.0000
Tank Diameter (ft):	9.7600
Working Loss Product Factor:	1.0000
Total Losses (lb):	6.8102

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Lube Oil Tank #1 & #2 (Each) - Horizontal Tank
Central City, Kentucky

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Aliphatics (Mineral Spirits)	0.01	6.80	6.81

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Lube Oil Tank #3
City:	Central City
State:	Kentucky
Company:	KU
Type of Tank:	Horizontal Tank
Description:	Lube Oil Tank #3

Tank Dimensions

Shell Length (ft):	15.00
Diameter (ft):	11.69
Volume (gallons):	12,050.00
Turnovers:	0.01
Net Throughput(gal/yr):	88.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Evansville, Indiana (Avg Atmospheric Pressure = 14.56 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Lube Oil Tank #3 - Horizontal Tank
Central City, Kentucky

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Aliphatics (Mineral Spirits)	All	57.53	52.15	62.91	55.74	0.0240	0.0244	0.0236	162.0000			162.00	Option 2: A=-.5143, B=-165.5177, C=257.923

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Lube Oil Tank #3 - Horizontal Tank
Central City, Kentucky

Annual Emission Calcaulations	
Standing Losses (lb):	9.7463
Vapor Space Volume (cu ft):	1,025.4406
Vapor Density (lb/cu ft):	0.0007
Vapor Space Expansion Factor:	0.0374
Vented Vapor Saturation Factor:	0.9926
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	1,025.4406

Tank Diameter (ft):	11.6900
Effective Diameter (ft):	14.9458
Vapor Space Outage (ft):	5.8450
Tank Shell Length (ft):	15.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0007
Vapor Molecular Weight (lb/lb-mole):	162.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Daily Avg. Liquid Surface Temp. (deg. R):	517.1990
Daily Average Ambient Temp. (deg. F):	55.7250
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	515.4150
Tank Paint Solar Absorptance (Shell):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,334.9400
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0374
Daily Vapor Temperature Range (deg. R):	21.5223
Daily Vapor Pressure Range (psia):	-0.0007
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0244
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0236
Daily Avg. Liquid Surface Temp. (deg R):	517.1990
Daily Min. Liquid Surface Temp. (deg R):	511.8184
Daily Max. Liquid Surface Temp. (deg R):	522.5796
Daily Ambient Temp. Range (deg. R):	21.0667
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9926
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0240
Vapor Space Outage (ft):	5.8450
Working Losses (lb):	0.0081
Vapor Molecular Weight (lb/lb-mole):	162.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0240
Annual Net Throughput (gal/yr.):	88.0000
Annual Turnovers:	0.0073
Turnover Factor:	1.0000
Tank Diameter (ft):	11.6900
Working Loss Product Factor:	1.0000
Total Losses (lb):	9.7544

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Lube Oil Tank #3 - Horizontal Tank
Central City, Kentucky

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Aliphatics (Mineral Spirits)	0.01	9.75	9.75

TANKS 4.0.9d
Emissions Report - Detail Format
Total Emissions Summaries - All Tanks in Report

Emissions Report for: Annual

Tank Identification				Losses (lbs)
Diesel Tank #6	KU	Horizontal Tank	Central City, Kentucky	0.56
Diesel Tank #7	KU	Horizontal Tank	Central City, Kentucky	0.39
Lube Oil Tank #1 & #2 (Each)	KU	Horizontal Tank	Central City, Kentucky	6.81
Lube Oil Tank #3	KU	Horizontal Tank	Central City, Kentucky	9.75
Total Emissions for all Tanks:				17.52

APPENDIX D: BACT ANALYSES SUPPORTING INFORMATION

Table D-1. NGCC Combustion Turbine RBLC Search Results - CO

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
VA-0308	Virginia Electric and Power - Warren County Facility	VA	12/21/2010	Mitsubishi M501 GAC	2,996 CT 500 DB	Oxidation Catalyst	1.5	ppmvd at 15% O2 without duct burners	1-hour	Not Comparable - Commercial operation scheduled for late 2014 or early 2015. Therefore, compliance with this BACT limit has not been demonstrated.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	12/21/2010	Mitsubishi M501 GAC	2,996 CT 500 DB	Oxidation Catalyst	2.4	ppmvd at 15% O2 with duct burners	1-hour	Not Comparable - Commercial operation scheduled for late 2014 or early 2015. Therefore, compliance with this BACT limit has not been demonstrated.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	1/14/2008	GE 7FA	1,717 CT 500 DB	Oxidation Catalyst	2.5	ppmvd at 15% O2 with power augmentation and DB firing	3-hour	Not Comparable - F-class turbine
CT-0151	Kleen Energy Systems, LLC	CT	2/25/2008	Siemens SGT6-5000F	2,136 CT 445 DB	Oxidation Catalyst	1.7	ppmvd at 15% O2 with duct burners	1-hour	Not Comparable - Limit does not apply to shifts between loads, and permit restricts turbine operation to 60+ percent load during normal operation.
CT-0151	Kleen Energy Systems, LLC	CT	2/25/2008	Siemens SGT6-5000F	2,136 CT 445 DB	Oxidation Catalyst	0.9	ppmvd at 15% O2 w/o duct burners	1-hour	Not Comparable - Limit does not apply to shifts between loads, and permit restricts turbine operation to 60+ percent load during normal operation.
GA-0127	Georgia Power - McDonough	GA	1/7/2008 (Title V)	Unknown	Unknown	Catalytic oxidation	1.8	ppmvd at 15% O2	3-hour	Not Comparable –Ability to achieve CO limit based on requirement to meet VOC LAER.
GA-9001	Live Oaks Power Plant	GA	4/8/2010	SGT6 - 5000F	1,990 CT 359 DB	Catalytic oxidation	2.0	ppmvd at 15% O2 without duct burners	3-hour	Not Comparable - F-class turbine
GA-9001	Live Oaks Power Plant	GA	4/8/2010	SGT6 - 5000F	1,990 CT 359 DB	Catalytic oxidation	3.2	ppmvd at 15% O2 with duct burners	3-hour	Not Comparable - F-class turbine
CA-9001	Calpine - Russell City Energy Center	CA	2/3/2010	SW 501F	2,038.6 CT 200 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	1-hour	Not Comparable - F-class turbine
WA-0315	Sumas Energy 2 Generation Facility	WA	3/11/2004	SW	Unknown	Catalytic Oxidation	2.0	ppmvd at 15% O2	1-hour	
TX-0546	Pattillo Branch Power Company, LLC - Electric Generating Plant	TX	6/17/2009	GE 7FA, GE 7FB, or SGT6-5000F	444 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
NY-0095	Caithness Bellport Energy Center	NY	5/10/2006	Unknown	2,221 CT 494 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	
OR-0041	Wanapa Energy Center	OR	8/8/2005	GE 7241FA	1,779 CT 606 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
MI-0366	Berrien Energy, LLC	MI	4/13/2005	Unknown	1,584 CT 650 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	
WA-0328	BP Cherry Point Cogeneration Project	WA	1/11/2005	GE 7FA	1,614 CT 105 DB	Lean Pre-mix & Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation Catalyst	24.5	ppmvd at 15% O2	3-hour rolling during low load events	Not Comparable - F-class turbine
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation catalyst	2,510	lb/hr	1-hour during startup and shutdown	Not Comparable - F-class turbine
TX-0590	Pondera Capital Management GP Inc., King Power Station	TX	8/5/2010	SGT6 - 5000F	Unknown	DLN Burners and oxidation catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine
TX-0590	Pondera Capital Management GP Inc., King Power Station	TX	8/5/2010	GE 7FA	Unknown	DLN Burners and oxidation catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	TX	9/1/2011	GE 7FA	Unknown	Oxidation catalyst	4.0	ppmvd at 15% O2	3-hour rolling at load >60%	Not Comparable - F-class turbine
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	TX	9/1/2011	GE 7FA	Unknown	Oxidation catalyst	6.0	ppmvd at 15% O2	3-hour rolling at load <60%	Not Comparable - F-class turbine

Table D-1. NGCC Combustion Turbine RBLC Search Results - CO

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
AZ-0047	Dome Valley Energy Partners - Wellton Mohawk Generating Facility	AZ	12/1/2004	GE 7FA or SW 501F	Unknown	Oxidation Catalyst	3.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
NV-0037	Sempra Energy Resources - Copper Mountain Power	NV	5/14/2004	Unknown	695 DB	Oxidation Catalyst	3.0	ppmvd at 15% O2	3-hour	Not Comparable - LAER Limit
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	3.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
NV-0035	Sierra Pacific Power Company - Tracy Substation	NV	8/16/2005	Unknown	Unknown	Oxidation Catalyst	3.5	ppmvd at 15% O2	3-hour	
CA-1144	Caithness Blythe II, LLC - Blythe Energy Project	CA	4/25/2007	Siemens V84.3A	Unknown	Good Combustion Practices	4.0	ppmvd at 15% O2	24-hour	
NC-9001	Richmond County Combustion Turbine Facility	NC	4/2/2009	SGT6 - 5000F	2,225 CT 390 DB	Good Combustion Practices	4.0	ppmvd at 15% O2	AVG of 3, 1-hour runs	Not Comparable - F-class turbine
FL-0303	FP&L - West County Energy Center	FL	7/30/2008	SW 501G	2,333 CT (LHV) 428 DB (LHV)	Oxidation Catalyst	4.1	ppmvd at 15% O2 without duct burners	24-hour	
FL-0303	FP&L - West County Energy Center	FL	7/30/2008	SW 501G	2,333 CT (LHV) 428 DB (LHV)	Oxidation Catalyst	7.6	ppmvd at 15% O2 with duct burners	24-hour	
FL-9001	OUC - Curtis H. Stanton Energy Center	FL	5/4/2008	GE 7FA	1,922 CT (HHV) 531 DB (HHV)	Good Combustion Practices	4.1	ppmvd at 15% O2	3-run average without DB	Not Comparable - F-class turbine
FL-9001	OUC - Curtis H. Stanton Energy Center	FL	5/4/2008	GE 7FA	1,922 CT (HHV) 531 DB (HHV)	Good Combustion Practices	7.6	ppmvd at 15% O2	3-run average with DB	Not Comparable - F-class turbine
FL-9001	OUC - Curtis H. Stanton Energy Center	FL	5/4/2008	GE 7FA	1,922 CT (HHV) 531 DB (HHV)	Good Combustion Practices	8.0	ppmvd at 15% O2	24-hour	Not Comparable - F-class turbine
FL-0304	FMPA - Cane Island Power Park	FL	9/8/2008	GE 7FA	1,860 CT 600 DB	Good Combustion Practices	6.0	ppmvd at 15% O2	Annual	Not Comparable - F-class turbine
FL-0304	FMPA - Cane Island Power Park	FL	9/8/2008	GE 7FA	1,860 CT 600 DB	Good Combustion Practices	8.0	ppmvd at 15% O2	24-hour	Not Comparable - F-class turbine
FL-9003	FP&L Company - Riviera Beach Energy Center	FL	6/10/2009	Mitsubishi "G" Class, Siemens "H" Class	2,586 CT (LHV), 460 DB (LHV)	Oxidation Catalyst	7.5	ppmvd at 15% O2	30-day rolling	
FL-0263	FP&L - Turkey Point Fossil Plant	FL	2/8/2005	GE 7FA	1,608 CT (LHV) 495 DB (LHV)	Good Combustion Practices	8.0	ppmvd at 15% O2, for NG and Oil	24-hour	Not Comparable - F-class turbine
OK-0129	Associated Electric Cooperative, Inc. - Chouteau Power Plant	OK	1/20/2009	Siemens V84.3A	1,882 CT (unknown if HHV or LHV) 100 DB	Good Combustion Practices	8.0	ppmvd at 15% O2	1-hour	
FL-9002	FP&L Company - Cape Canaveral Energy Center	FL	7/23/2009	Mitsubishi "G" Class, Siemens "H" Class	2,586 CT (LHV), 460 DB (LHV)	Oxidation Catalyst	8.0	ppmvd at 15% O2	30-day rolling	
LA-0224	SWEPCO - Arsenal Hill Power Plant	LA	3/20/2008	Unknown	2,110 CCCT 250 DB	Good Combustion Practices	10.0	ppmvd at 15% O2	Annual	
NC-0101	Forsyth Energy Projects, LLC	NC	9/29/2006	Unknown	1,844.3 CT	--	11.6	ppmvd at 15% O2	3-hour	
OH-0356	Duke Energy Hanging Rock Energy	OH	12/18/2012	GE 7FA	Unknown	Good combustion practices, Burning natural gas	6.0	ppmvd at 15% O2, without duct burners	24-hour	Not Comparable - F-class turbine

Table D-1. NGCC Combustion Turbine RBLC Search Results - CO

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
OH-0356	Duke Energy Hanging Rock Energy	OH	12/18/2012	GE 7FA	Unknown	Good combustion practices, Burning natural gas	8.0	ppmvd at 15% O2, with duct burners	24-hour	Not Comparable - F-class turbine
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	GE 7FA	2,300 CT	Oxidation Catalyst	2.0	ppmvd at 15% O2, with duct burners	3-hour	Not Comparable - F-class turbine
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	GE 7FA	2,300 CT	Oxidation Catalyst	2125	lb	event	Not Comparable - F-class turbine
TX-0641	Pinecrest Energy Center	TX	11/12/2013	GE 7FA.05, Siemens SGT6-5000F(4), or Siemens SGT6-5000F(5)	Unknown	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
DE-0023	NRG Energy Center Dover	DE	10/31/2012	GE LM6000	500 CT	Oxidation Catalyst System	19.5	lb/hr	1-hour	
TX-0618	Channel Energy Center LLC	TX	10/15/2012	Siemens 501F	475 DB	Good combustion	4.0	ppmvd at 15% O2	24-hour	Not Comparable - F-class turbine
TX-0619	Deer Park Energy Center	TX	9/26/2012	Siemens 501F	725 DB	Good combustion	4.0	ppmvd at 15% O2	24-hour	Not Comparable - F-class turbine
TX-0620	Es Joslin Power Plant	TX	9/12/2012	Unknown	Unknown	Good combustion	4.0	ppmvd at 15% O2	24-hour	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Unknown	Unknown	Oxidation Catalyst	4.0	ppmv at 15% O2	1-hour	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Unknown	Unknown	Oxidation Catalyst	4.0	ppmv at 15% O2	1-hour	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens SGT-8000H	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens SGT-8000H	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi M501 GAC	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi M501 GAC	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	
PA-0291	Hickory Run Energy Station	PA	4/23/2013	GE 7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H	3,468 CT	CO catalyst	2.0	ppmvd at 15% O2	Unknown	
PA-0286	Moxie Energy LLC/Patriot Generation PLT	PA	1/31/2013	Unknown	Unknown	CO Catalyst	2.0	ppmvd	Unknown	

Table D-2. NGCC Combustion Turbine RBLC Search Results - VOC

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
OK-0129	Associated Electric Cooperative, Inc. - Chouteau Power Plant	OK	1/20/2009	Siemens V84.3A	1,882 CT (unknown if HHV or LHV) 100 DB	Good Combustion Practices	0.3	ppmvd at 15% O2	Unknown	Not Comparable - Plant is designed for baseload operation and will therefore startup and shut-down much less frequently than a typical NGCC combustion turbine plant.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	12/21/2010	Mitsubishi M501 GAC	2,996 CT 500 DB	Oxidation Catalyst	0.7	ppmvd at 15% O2 without duct burners	3-hour	Not Comparable - Commercial operation scheduled for late 2014 or early 2015. Therefore, compliance with this BACT limit has not been demonstrated.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	12/21/2010	Mitsubishi M501 GAC	2,996 CT 500 DB	Oxidation Catalyst	1.6	ppmvd at 15% O2 with duct burners	3-hour	Not Comparable - Commercial operation scheduled for late 2014 or early 2015. Therefore, compliance with this BACT limit has not been demonstrated.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	1/14/2008	GE 7FA	1,717 CT 500 DB	Oxidation Catalyst	1.4	ppmvd at 15% O2 with power augmentation and DB firing	3-hour	Not Comparable - Superceded by permit issued December 21, 2010.
VA-0308	Virginia Electric and Power - Warren County Facility	VA	1/14/2008	SGT6 - 5000F	2,204 CT 210 DB	Oxidation Catalyst	1.4	ppmvd at 15% O2 with duct burners	3-hour	Not Comparable - Superceded by permit issued December 21, 2010.
GA-0127	Georgia Power - McDonough	GA	1/7/2008 (Title V)	Unknown	Unknown	Catalytic oxidation	1.0	ppmvd at 15% O2 as methane without duct burners	3-hour	Not Comparable - LAER Limit
GA-0127	Georgia Power - McDonough	GA	1/7/2008 (Title V)	Unknown	Unknown	Catalytic oxidation	1.8	ppmvd at 15% O2 as methane with duct burners	3-hour	Not Comparable - LAER Limit
CA-1144	Caithness Blythe II, LLC - Blythe Energy Project	CA	4/25/2007	Siemens V84.3A	Unknown	Good combustion practices	1.0	ppmvd at 15% O2	1-hour	Not Comparable - Located in a state nonattainment area for ozone, requiring source to obtain offsets for VOC emissions.
NY-0100	Empire Power Plant (LAER, not PSD BACT)	NY	6/23/2005	GE Frame 7FA	2,099 CT	Oxidation Catalyst	1.0	ppmvd at 15% O2	Unknown	Not Comparable - LAER Limit
FL-0303	FP&L - West County Energy Center	FL	7/30/2008	SW 501G	2,333 CT (LHV) 428 DB (LHV)	Oxidation Catalyst	1.2	ppmvd at 15% O2	3-hr initial	Not Comparable - Limit applies at 90-100 percent load only.
FL-0285	Progress Energy Florida - Bartow Power Plant	FL	1/26/2007	SGT6 5000F	2,006 CT 500 DB	No control required by permit.	1.2	ppmvd at 15% O2 (CT only)	--	Not Comparable - Compliance with the CO CEMS-based limit is deemed compliance with the VOC limit. Therefore, compliance with this BACT limit has not been demonstrated.
FL-0285	Progress Energy Florida - Bartow Power Plant	FL	1/26/2007	SGT6 5000F	2,006 CT 500 DB	No control required by permit.	1.5	ppmvd at 15% O2 (CT with DB only)	--	Not Comparable - Compliance with the CO CEMS-based limit is deemed compliance with the VOC limit. Therefore, compliance with this BACT limit has not been
FL-0263	FP&L - Turkey Point Fossil Plant	FL	2/8/2005	GE 7FA	1,608 CT (LHV) 495 DB (LHV)	Good Combustion Practices	1.3	ppmvd at 15% O2 (CT only)	3-run average	Not Comparable - Permit does not require stack testing to demonstrate compliance unless requested by the department. No stack test reports were found. Therefore, compliance with this BACT limit has not been demonstrated.
FL-0263	FP&L - Turkey Point Fossil Plant	FL	2/8/2005	GE 7FA	1,608 CT (LHV) 495 DB (LHV)	Good Combustion Practices	1.9	ppmvd at 15% O2 (CT and DB)	3-run average	Not Comparable - Permit does not require stack testing to demonstrate compliance unless requested by the department. No stack test reports were found. Therefore, compliance with this BACT limit has not been demonstrated.
MN-0053	Minnesota Municipal Power Agency - Fairbault Energy Park	MN	6/5/2007	GE 7FA	1,758 CTs 249 DB	Unknown	3.0	ppmvd at 15% O2 with duct burners	3-hour	Not Comparable - Separate limits with and without duct burner firing.
MN-0053	Minnesota Municipal Power Agency - Fairbault Energy Park	MN	6/5/2007	GE 7FA	1,758 CTs 249 DB	Unknown	1.5	ppmvd at 15% O2 without duct burners	3-hour	Not Comparable - Separate limits with and without duct burner firing.
TX-0590	Pondera Capital Management GP Inc., King Power Station	TX	8/5/2010	SGT6 - 5000F	Unknown	DLN Burners and oxidation catalyst	1.8	ppmvd at 15% O2	3-hour rolling	Not Comparable - LAER Limit
TX-0590	Pondera Capital Management GP Inc., King Power Station	TX	8/5/2010	GE 7FA	Unknown	DLN Burners and oxidation catalyst	1.8	ppmvd at 15% O2	3-hour rolling	Not Comparable - LAER Limit
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine
ID-0018	Idaho Power Company Langley Gulch Power Plant	ID	6/25/2010	SGT6 - 5000F	2,134 CT 241.28 DB	Oxidation Catalyst	11.5	ppmvd at 15% O2	3-hour rolling during low load events	Not Comparable - F-class turbine
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	TX	9/1/2011	GE 7FA	Unknown	Oxidation catalyst	2.0	ppmvd at 15% O2	3-hour rolling	Not Comparable - F-class turbine

Table D-2. NGCC Combustion Turbine RBLC Search Results - VOC

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
GA-9001	Live Oaks Power Plant	GA	4/8/2010	SGT6 - 5000F	1,990 CT 359 DB	Catalytic oxidation	2.0	ppmvd at 15% O2 as methane	3-hour	Not Comparable - F-class turbine
WA-0315	Sumas Energy 2 Generation Facility	WA	3/11/2004	SW	Unknown	Good Combustion Practices, Fuel Specifications	2.0	gr/100 cf gas	7-day	
TX-0546	Pattillo Branch Power Company, LLC - Electric Generating Plant	TX	6/17/2009	GE 7FA, GE 7FB, or SGT6-5000F	444 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
CA-9003	Sempra Energy Resources - Palomar Energy Project	CA	Unknown	GE 7FA	Unknown	Oxidation Catalyst	2.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
AZ-9001	Bowie Power Station, LLC	AZ	Unknown	GE 7FA	1,680 CT 420 DB	Oxidation Catalyst	2.6	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
AZ-9001	Bowie Power Station, LLC	AZ	Unknown	GE 7FA	1,680 CT 420 DB	Oxidation Catalyst	250	lb/hr during startup and shutdown	Unknown	Not Comparable - F-class turbine
AZ-0047	Dome Valley Energy Partners - Wellton Mohawk Generating Facility	AZ	12/1/2004	GE 7FA or SW 501F	Unknown	Oxidation Catalyst	3.0	ppmvd at 15% O2	3-hour	Not Comparable - F-class turbine
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	3.0	ppmvd at 15% O2	1-hour	Not Comparable - F-class turbine
MI-0366	Berrien Energy, LLC	MI	4/13/2005	Unknown	1,584 CT 650 DB	Oxidation Catalyst	3.2	lb/hr	Unknown	
NV-0035	Sierra Pacific Power Company - Tracy Substation	NV	8/16/2005	Unknown	Unknown	Oxidation Catalyst	4.0	ppmvd at 15% O2	3-hour	
NV-0037	Sempra Energy Resources - Copper Mountain Power	NV	5/14/2004	Unknown	695 DB	Oxidation Catalyst	4.0	ppmvd at 15% O2	3-hour	Not Comparable - LAER Limit
NY-0098	New Athens Generating Co, LLC - Athens Generating Plant (LAER, not PSD BACT)	NY	1/19/2007	Westinghouse Model 501G	3,100 CT	Good Combustion Control	4.0	ppmvd at 15% O2	3-hour	Not Comparable - LAER Limit
NC-0101	Forsyth Energy Projects, LLC	NC	9/29/2006	Unknown	1,844.3 CT	--	5.7	ppmvd at 15% O2	--	
NC-9001	Richmond County Combustion Turbine Facility	NC	4/2/2009	SGT6 - 5000F	2,225 CT 390 DB	Good Combustion Practices	1.0	ppmvd at 15% O2	AVG of 3, 1-hour runs	Not Comparable - Limit is without duct burners. Limit with duct burners at 60-100% load is 3.0 ppmvd at 15% O2.
LA-0224	SWEPCO - Arsenal Hill Power Plant	LA	3/20/2008	Unknown	2,110 CCCT 250 DB	Good Combustion Practices	4.9	ppmvd at 15% O2	Annual average	
LA-0224	SWEPCO- Arsenal Hill Power Plant (Cold start)	LA	3/21/2008	Unknown	2,110 CCCT 250 DB	Good Combustion Practices	214	lb/hr	Annual average	
LA-0224	SWEPCO - Arsenal Hill Power Plant (Hot start)	LA	3/21/2008	Unknown	2,110 CCCT 250 DB	Good Combustion Practices	214	lb/hr	Annual average	
LA-0224	SWEPCO - Arsenal Hill Power Plant (Shutdown)	LA	3/21/2008	Unknown	2,110 CCCT 250 DB	Good Combustion Practices	214	lb/hr	Annual average	
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	370.3 790.5	lb/hr WS lb/event WS	per event	Not Comparable - F-class turbine
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	373.6 1355.6	lb/hr CS lb/event CS	per event	Not Comparable - F-class turbine
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	429.6 679.6	lb/hr HS lb/event HS	per event	Not Comparable - F-class turbine
CA-9002	PG&E - Colusa Generating Station	CA	9/29/2008	GE 7FA	1,917.2 CT 688 DB	Oxidation Catalyst	483.5 483.5	lb/hr SD lb/event SD	per event	Not Comparable - F-class turbine

Table D-2. NGCC Combustion Turbine RBLC Search Results - VOC

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
OH-0356	Duke Energy Hanging Rock Energy	OH	12/18/2012	GE 7FA	Unknown	Using efficient combustion technology	44.1	tpy	12-month rolling average	Not Comparable - F-class turbine
OH-0356	Duke Energy Hanging Rock Energy	OH	12/18/2012	GE 7FA	Unknown	Using efficient combustion technology	44.1	tpy	12-month rolling average	Not Comparable - F-class turbine
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	GE 7FA	2300 CT	Oxidation Catalyst	1.0	ppmvd at 15% O2, without duct burners	3-hour	Not Comparable - Limit is for operation without duct burners. Limit with duct burners is 2.0 ppmvd at 15% O2.
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	GE 7FA	2300 CT	Oxidation Catalyst	22	tpy	12-month rolling average	Not Comparable - F-class turbine
TX-0641	Pinecrest Energy Center	TX	11/12/2013	GE 7FA.05, Siemens SGT6-5000F(4), or Siemens SGT6-5000F(5)	Unknown	Oxidation Catalyst	2.0	ppmvd at 15% O2	Unknown	Not Comparable - F-class turbine
DE-0023	NRG Energy Center Dover	DE	10/31/2012	GE LM6000	500 CT	Oxidation Catalyst	6.4	lb/hr	1-hour	
TX-0618	Channel Energy Center LLC	TX	10/15/2012	Siemens 501F	475 DB	Good combustion	2.0	ppmvd at 15% O2	Unknown	Not Comparable - F-class turbine
FL-0337	Polk Power Station	FL	10/14/2012	Unknown	Unknown	Unknown	1.4	ppmvd at 15% O2	Unknown	Not Comparable - Construction to commence in 2014. Therefore, compliance with this BACT limit has not been demonstrated.
TX-0619	Deer Park Energy Center	TX	9/26/2012	Siemens 501F	725 DB	Good combustion, Natural gas	2.0	ppmvd at 15% O2	Unknown	Not Comparable - F-class turbine
TX-0620	Es Joslin Power Plant	TX	9/12/2012	Unknown	Unknown	Good combustion, Natural gas	2.0	ppmvd at 15% O2	Unknown	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Unknown	Unknown	Oxidation Catalyst	3.0	ppmvd at 15% O2	1-hour	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Unknown	Unknown	Oxidation Catalyst	3.0	ppmv at 15% O2	3-hour	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens SGT-8000H	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2, without duct burners	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens SGT-8000H	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2, with duct burners	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi M501 GAC	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2, without duct burners	Unknown	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi M501 GAC	2,932 CT 300 DB	Oxidation Catalyst	2.0	ppmvd at 15% O2, with duct burners	Unknown	
PA-0291	Hickory Run Energy Station	PA	4/23/2013	GE 7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H	3,468 CT	Oxidation Catalyst	1.5	ppmvd at 15% O2	Unknown	Not Comparable - Construction to commence in 2014. Therefore, compliance with this BACT limit has not been demonstrated.
PA-0286	Moxie Energy LLC/Patriot Generation PLT	PA	1/31/2013	Unknown	Unknown	CO Catalyst	1.0	ppmvd	Unknown	Not Comparable - Construction completion projected for mid-2015. Therefore, compliance with this BACT limit has not been demonstrated.

Table D-3. NGCC Combustion Turbine RBLC Search Results - GHGs

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Averaging Period	Note(s)
IN-0158	St. Joseph Energy Center, LLC	IN	12/3/2012	GE 7FA	2,300 CT	Unknown	7,646	Btu/kW-hr		Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	19.7	tpy CH4	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	2.0	tpy N2O	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	1,062,627	tpy CO2	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	19.3	tpy CH4	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	1.9	tpy N2O	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0632	Deer Park Energy Center LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	0.5	ton CO2/MW-hr	30-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	18.2	tpy CH4	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	1.8	tpy N2O	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	984,393	tpy CO2	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	18.6	tpy CH4	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	1.9	tpy N2O	365-Day Rolling Average	Not Comparable - F-class turbine
TX-0633	Channel Energy Energy Center, LLC	TX	11/29/2012	Siemens Model FD2 (to be upgraded to FD3 in project phase 2)	Unknown	Unknown	10,020,391	tpy CO2	365-Day Rolling Average	Not Comparable - F-class turbine
DE-0023	NRG Energy Center Dover	DE	10/31/2012	Unknown	500 CT	Unknown	1,085	lbs CO2e/ MW-hr gross	12-Month Rolling Average	
VA-0319	Gateway Cogeneration 1, LLC - Smart Water Project	VA	8/27/2012	Rolls Royce Trent 60 WLE	593 CT	Unknown	295,961	tpy CO2e	12-Month Rolling Average	
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens	2932 CT 300 DB	Unknown	1,000	lb CO2/MW-hr gross		
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Siemens	2932 CT 300 DB	Unknown	1,000	lb CO2/MW-hr gross		
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi	2932 CT 300 DB	Unknown	1,000	lb CO2/MW-hr gross		
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Mitsubishi	2932 CT 300 DB	Unknown	1,000	lb CO2/MW-hr gross		
PA-0291	Hickory Run Energy Station	PA	4/23/2013	GE 7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H	3,468 CT	Unknown	3,665,974	tpy CO2e	12-Month Rolling Total For Both Units	
DE-0024	Garrison Energy Center	DE	1/30/2013	GE	Unknown	Unknown	1,006,304	tons CO2e	12-Month Rolling Average	

Table D-4. Auxiliary Boiler RBLC Search Results - CO

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Avg. Period	Note(s)
OH-0354	Kraton Polymers U.S. LLC	OH	1/15/2013	Two 249 MMBtu/hr boilers	249	Use of clean fuels and good combustion practices	0.075	lb/MMBtu		Not Comparable - Limit is for burning natural gas with belpre naphtha.
NC-0101	Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	110.2	Low NO_X Burners & Good Combustion Control	0.082	lb/MMBtu	3-Hour average	
OH-0310	American Municipal Power Generating Station	OH	10/8/2009	Auxiliary Boiler	150		0.084	lb/MMBtu		
LA-0246	Valero St. Charles Refinery	LA	7/6/2011	Boiler	99	Proper design and operation, good combustion practices and gaseous fuels	0.092	lb/MMBtu		
TX-0641	Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	150	Pipeline quality natural gas and good combustion	75	ppmvd at 3% O2		

Table D-5. Auxiliary Boiler RBLC Search Results - VOC

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Avg. Period	Note(s)
OR-0046	Turner Energy Center, Llc	OR	1/6/2005	Auxiliary Boiler	418	Oxidation Catalyst	0.004	lb/MMBtu	3-Hour Block	Not Comparable - Oxidation catalyst is not economically feasible.
NC-0101	Forsyth Energy Plant	NC	9/29/2005	Auxiliary Boiler	110	Low NO_X Burners, Good Combustion Control, & Natural Gas Only	0.005	lb/MMBtu	3-Hour	
LA-0246	Valero St. Charles Refinery	LA	7/6/2011	Boiler	99	Proper design and operation, good combustion practices and gaseous fuels	0.005	lb/MMBtu		
TX-0641	Pinecrest Energy Center	TX	11/12/2013	Auxiliary Boiler	150	Pipeline quality natural gas and good combustion	0.006	lb/hr		

Table D-6. Auxiliary Boiler RBLC Search Results - GHGs

ID	Company/Facility	State	Permit Issuance Date	Process Type	Capacity (MMBtu/hr)	Control Type	Limit	Limit Units	Avg. Period	Note(s)
OH-0354	Kraton Polymers U.S. LLC	OH	1/15/2013	Two boilers	249		357,522	ton CO2e/yr	-	

Table D-7. Emergency Generator RBLC Search Results - CO

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
AK-0061	Snake River Power Plant	AK	11/5/2004	Wartsila 12V32B Diesel Electric Generator	5,211	kW	Good Combustion Practices	10.5	lb/hr	3-hour @ 100% load	
MN-0071	Fairbault Energy Park	MN	6/5/2007	Emergency Generator	1,750	kW		0.006	lb/hp-hr	3-hour average	
FL-0310	Shady Hills Generating Station	FL	1/12/2009	2.5 MW Emergency Generator	2.5	MW	Purchased model is at least as stringent as BACT values under EPA's Certification.	8.5	g/hp-hr	3 one hour test runs	
ID-0018	Langley Gulch Power Plant	ID	6/25/2010	Emergency Generator Engine	750	kW	Tier 2 Engine-Based, Good Combustion Practices (GCP)	3.5	g/kW-hr		
MN-0053	Fairbault Energy Park	MN	7/15/2004	IC Engine, Large, Fuel Oil (1)	670	hp	Good Combustion	0.76	lb/MMBtu	3-hour average	
MN-0053	Fairbault Energy Park	MN	7/15/2004	IC Engine, Small, Fuel Oil (1)	250	hp	Good Combustion	0.95	lb/MMBtu	3-hour average	
MI-0389	Karn Weadock Generating Complex	MI	12/29/2009	Emergency Generator	2,000	kW	Engine Design And Operation, 15 ppm sulfur fuel	3.5	g/kW-hr	Test method	
OH-0275	PSI Energy-Madison Station	OH	8/24/2004	Emergency Diesel Generator, 2	17.21	MMBtu/hr		14.63	lb/hr		
OK-0129	Chouteau Power Plant	OK	1/23/2009	Emergency Diesel Generator (2,200 Hp)	2,200	hp		12.66	lb/hr		
WV-0023	Maidsville	WV	3/2/2004	Emergency Generator	1,801	hp	Good Combustion Practices	8.85	lb/hr		
AK-0076	Point Thomson Production Facility	AK	08/20/2012	Combustion Of Diesel By ICEs	1,750	kW		3.5	g/kW-hr		
IA-0105	Iowa Fertilizer Company	IA	10/26/2012	Emergency Generator	142	gal/hr	Good Combustion Practices	3.5	g/kW-hr	Average Of 3 Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	07/12/2013	Emergency Generators	180	gal/hr	Good Combustion Practices	3.5	g/kW-hr	Average Of Three (3) Stack Test Runs	
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Two (2) Emergency Diesel Generators	1,006	hp (each)	Combustion Design Controls And Usage Limits	2.6	g/hp-hr		
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Emergency Diesel Generator	2,012	hp	Combustion Design Controls And Usage Limits	2.6	g/hp-hr	3 Hours	
IN-0166	Indiana Gasification, LLC	IN	6/27/2012	Two (2) Emergency Generators	1,341	hp (each)	Good Combustion Practices And Limited Hours Of Non-Emergency Operation				
NJ-0079	Woodbridge Energy Center	NJ	7/25/2012	Emergency Generator	100	hr/yr	Use Of ULSD Oil	1.99	lb/hr		Not Comparable - Under construction. Therefore, compliance with this BACT limit has not been demonstrated.
NJ-0080	Hess Newark Energy Center	NJ	11/01/2012	Emergency Generator	200	hr/yr		11.56	lb/hr		
NJ-0080	Oregon Clean Energy Center	OH	6/18/2013	Emergency Generator	2,250	kW	Purchased Certified To The Standards In NSPS Subpart IIII	17.35	lb/hr		
OH-0352	Hickory Run Energy Station	PA	4/23/2013	Emergency Generator	7.8	MMBtu/hr		5.79	lb/hr		
PA-0291	Ml 35 LLC/Phila Cybercenter	PA	6/1/2012	Diesel Generator (2.25 MW Each) - 5 Units	2.3	MW	CO Oxidation Catalyst	3.5	g/kW-hr		
SC-0113	Pyramax Ceramics, LLC	SC	2/8/2012	Emergency Generators 1 Thru 8	757	hp	Engines Must Be Certified To Comply With NSPS, Subpart IIII	3.5	g/kW-hr		
SC-0113	Cheyenne Prairie Generating Station	WY	8/28/2012	Diesel Emergency Generator (EP15)	839	hp	EPA Tier 2 Rated				

Table D-8. Emergency Generator RBLC Search Results - VOC

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
ID-0018	Langley Gulch Power Plant	ID	6/25/2010	Emergency Generator Engine	750	kW	Tier 2 Engine-Based, Good Combustion Practices (GCP)	6.4	g/kW-hr	NOx+NMHC	
MN-0053	Fairbault Energy Park	MN	7/15/2004	IC Engine, Small, Fuel Oil (1)	250	hp	Good Combustion	0.4	lb/MMBtu	3-hour Average	
MN-0053	Fairbault Energy Park	MN	7/15/2004	IC Engine, Large, Fuel Oil (1)	670	hp	Good Combustion	0.1	lb/MMBtu	3-hour Average	
MN-0071	Fairbault Energy Park	MN	6/5/2007	Emergency Generator	1,750	kW		0.001	lb/hp-hr	3-hour Average	Not Comparable - Significantly larger engine (1,750 kW) capable of achieving lower emission
OH-0275	Psi Energy-Madison Station	OH	8/24/2004	Emergency Diesel Generator, 2	17.21	MMBtu/hr		1.6	lb/hr		
OK-0129	Chouteau Power Plant	OK	1/23/2009	Emergency Diesel Generator (2,200 hp)	2,200	hp	Good Combustion	1.6	lb/hr		
WV-0023	Maidsville	WV	3/2/2004	Emergency Generator	1,801	hp	Good Combustion Practices	1.2	lb/hr		
IA-0105	Iowa Fertilizer Company	IA	10/26/2012	Emergency Generator	142	gal/hr	Good Combustion Practices	0.4	g/kW-hr	Average of 3 Stack Test Runs	Not Comparable - Significantly larger engine (2,000 kW) capable of achieving lower emission limits.
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	07/12/2013	Emergency Generators	180	gal/hr	Good Combustion Practices	4.0	g/kW-hr	Average of 3 Stack Test Runs	
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Two (2) Emergency Diesel Generators	1,006	hp each	Combustion Design Controls And Usage Limits	1.0	lb/hr		Not Comparable - Facility not yet constructed. Therefore, compliance with this BACT limit has not been demonstrated.
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Emergency Diesel Generator	2,012	hp	Combustion Design Controls And Usage Limits	1.0	lb/hr	3-hour	Not Comparable - Facility not yet constructed. Therefore, compliance with this BACT limit has not been demonstrated.
NJ-0079	Woodbridge Energy Center	NJ	7/25/2012	Emergency Generator	100	hr/yr	Use Of ULSD Oil	0.5	lb/hr		Not Comparable - Under construction. Therefore, compliance with this BACT limit has not been demonstrated.
NJ-0080	Hess Newark Energy Center	NJ	11/01/2012	Emergency Generator	200	hr/yr	Use Of ULSD Oil	2.6	lb/hr		
OH-0352	Oregon Clean Energy Center	OH	6/18/2013	Emergency Generator	2,250	kW	Purchased Certified To The Standards In NSPS Subpart IIII	3.9	lb/hr		
PA-0291	Hickory Run Energy Station	PA	4/23/2013	Emergency Generator	7.8	MMBtu/hr		0.7	lb/hr		Not Comparable - Construction to commence in 2014. Therefore, compliance with this BACT limit has not been demonstrated.
SC-0113	Pyramax Ceramics, LLC	SC	2/8/2012	Emergency Generators	757	hp	Purchase Engines Certified To Comply With NSPS, Subpart IIII	4.0	g/kW-hr		
SC-0159	US10 Facility	SC	7/9/2012	Emergency Generators	1,000	kW	Compliance With NSPS, Subpart IIII	6.4	g/kW-hr	kW-hr	

Table D-9. Emergency Generator RBLC Search Results - GHGs

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
AK-0076	Point Thomson Production Facility	AK	8/20/2012	Combustion Of Diesel By ICEs	1750	kW	Good Combustion Practices and NSPS Subpart IIII Requirements				
AK-0081	Point Thomson Production Facility	AK	6/12/2013	Combustion	610	hp	Good Combustion And Operating Practices				
IA-0105	Iowa Fertilizer Company	IA	10/26/2012	Emergency Generator	142	gal/hr	Good Combustion Practices	0.0001	g/kW-hr	Average Of 3 Stack Test Runs	
IA-0105	Iowa Fertilizer Company	IA	10/26/2012	Emergency Generator	142	gal/hr	Good Combustion Practices	788.50	tpy	Rolling 12 Month Total	
IA-0105	Iowa Fertilizer Company	IA	10/26/2012	Emergency Generator	142	gal/hr	Good Combustion Practices	1.55	g/kW-hr	Average Of 3 Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Emergency Generators	180	gal/hr	Good Combustion Practices	0.0001	g/kW-hr	Average Of Three (3) Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Emergency Generators	180	gal/hr	Good Combustion Practices	509.00	tpy	Rolling Twelve (12) Month Total	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Emergency Generators	180	gal/hr	Good Combustion Practices	1.55	lb/kW-hr	Average Of Three (3) Stack Test Runs	
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Two (2) Emergency Diesel Generators	1,006	hp each	Good Engineering Design And Fuel Efficient Design	1,186.00	tons	12 Consecutive Month Period	
IN-0158	St. Joseph Energy Center, LLC	IN	12/03/2012	Emergency Diesel Generator	2,012	hp	Good Engineering Design And Fuel Efficient Design	1,186.00	tons	12 Consecutive Month Period	
IN-0166	Indiana Gasification, LLC	IN	6/27/2012	Two (2) Emergency Generators	1,341	hp	Use Of Good Engineering Design And Efficient Engines Meeting Applicable NSPS And Mact Standards	84.00	tpy	Twelve Consecutive Months	
IN-0166	Oregon Clean Energy Center	OH	6/18/2013	Emergency Generator	2,250	kW		878.00	tpy	Per Rolling 12-Months	
OH-0352	Hickory Run Energy Station	PA	4/23/2013	Emergency Generator	7.8	MMBtu/hr		80.50	tpy	12-Month Rolling Basis	

Table D-10. Fire Pump Engine RBLC Search Results - CO

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
LA-0194	Sabine Pass LNG Terminal	LA	11/24/2004	Firewater Pump Diesel Engines 1-3	660	hp each	Good Engine Design And Proper Operating Practices	0.6	lb/hr	Hourly Maximum	
MI-0389	Karn Weadock Generating Complex	MI	12/29/2009	Fire Pump	525	hp	Engine Design And Operation. 15 ppm Sulfur Fuel	2.6	g/hp-hr	Test Method	
MI-0391	Karn Weadock Generating Complex	MI	12/29/2009	Fire Booster Pump	40	kW	Engine Design And Operation. 15 ppm Sulfur Fuel.	5.0	g/kW-hr	Test Method	
ID-0018	Power County Advanced Energy Center	ID	2/10/2009	500 kW Emergency Generator, Fire Pump	500	kW	Good Combustion Practices. EPA Certification Per NSPS IIII				
NC-0102	Forsyth Energy Plant	NC	9/29/2005	IC Engine, Emergency Firewater Pump	11.4	MMBtu/hr		9.7	lb/hr		
WI-0229	WPS - Weston Plant	WI	10/19/2004	Main Fire Pump (Diesel Engine)	460	hp	Good Combustion Practices, Ultra Low Sulfur Diesel Fuel Oil	3.1	lb/hr	200 H / 12 Mo. Rolling	
WV-0024	Maidsville	WV	3/2/2004	IC Engine, Fire Water Pump	85	hp	Good Combustion Practices	4.4	lb/hr		
IN-0166	Indiana Gasification, LLC	IN	6/27/2012	Three (3) Firewater Pump Engines	575	hp each	Good Combustion Practices And Limited Hours Of Non-Emergency Operation				

Table D-11. Fire Pump Engine RBLC Search Results - VOC

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
LA-0194	Sabine Pass LNG Terminal	LA	11/24/2004	Firewater Pump Diesel Engines 1-3	660	hp each	Good Combustion Practices	0.1	lb/hr	Hourly Maximum	
NC-0102	Forsyth Energy Plant	NC	9/29/2005	IC Engine, Emergency Firewater Pump	11.4	MMBtu/hr		1.0	lb/hr		
WI-0229	WPS - Weston Plant	WI	10/19/2004	Main Fire Pump (Diesel Engine)	460	hp	Good Combustion Practices, Ultra Low Sulfur Diesel Fuel Oil	1.1	lb/hr	200 H / 12 Mo. Rolling Limit	
WV-0024	Maidsville	WV	3/2/2004	IC Engine, Fire Water Pump	85	hp	Good Combustion Practices	0.6	lb/hr		
ID-0018	Langley Gulch Power Plant	ID	6/25/2010	Fire Pump Engine	235	kW	Tier 3 Engine-Based, Good Combustion Practices (GCP)	4.0	g/kW-hr		
LA-0254	Ninemile Point Electric Generating Plant	LA	8/16/2011	Emergency Fire Pump	350	hp	Ultra Low Sulfur Diesel And Good Combustion Practices	1.0	g/kW-hr	Annual Average	

Table D-12. Fire Pump Engine RBLC Search Results - GHGs

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
IN-0166	Indiana Gasification, LLC	IN	6/27/2012	Three (3) Firewater Pump Engines	575	hp	Use Of Good Engineering Design And Efficient Engines Meeting Applicable NSPS And MACT Standards	84.0	tpy	Twelve Consecutive Months	

Table D-13. Fuel Gas Heater RBLC Search Results - CO

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
AK-0062	Badami Development Facility	AK	8/19/2005	Natco Miscible Injection Heater	14.9	MMBtu/hr	Good Operational Practices	0.1	lb/MMBtu		
AK-0062	Badami Development Facility	AK	8/19/2005	Natco Production Heater	34.0	MMBtu/hr	Good Operational Practices	0.1	lb/MMBtu		
CO-0058	Cheyenne Station	CO	6/12/2004	Heaters	45.0	MMBtu/hr	Good Combustion Practices	0.04	lb/MMBtu	1-Hr Average	Not Comparable - Limit is for amine treatment unit hot oil heaters.
IA-0088	Adm Corn Processing - Cedar Rapids	IA	6/29/2007	Indirect-Fired DDGS Dryer	93.7	MMBtu/hr	Low NOx Burners And Flue Gas Recirculation	0.1	lb/MMBtu	Average Of 3 Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	0.02	lb/MMBtu	Average Of Three (3) Stack Test Runs	Not Comparable - Permit does not require performance testing to demonstrate compliance. Therefore, compliance with this BACT limit has not been demonstrated.
LA-0192	Crescent City Power	LA	6/6/2005	Fuel Gas Heaters (3)	19	MMBtu/hr	Good Combustion Practices	1.5	lb/hr	Hourly Average	
LA-0203	Oakdale OSB Plant	LA	6/13/2005	Auxiliary Thermal Oil Heater	66.5	MMBtu/hr	Use Of Natural Gas As Fuel And Good Combustion Practices	6.6	lb/hr	Hourly Maximum	
LA-0231	Lake Charles Gasification Facility	LA	6/22/2009	Shift Reactor Startup Heater	34.2	MMBtu/hr	Good Design And Proper Operation	2.8	lb/hr	Maximum	
LA-0231	Lake Charles Gasification Facility	LA	6/22/2009	Gasifier Startup Preheater Burners (5)	35.0	MMBtu/hr	Good Design And Proper Operation	2.0	lb/hr	Maximum (Each)	
LA-0231	Lake Charles Gasification Facility	LA	6/22/2009	Methanation Startup Heaters	56.9	MMBtu/hr	Good Design And Proper Operation	4.7	lb/hr	Maximum	
MD-0035	Dominion	MD	8/12/2005	Vaporization Heater			Each Vaporization Heater Shall Only Use Natural Gas For Fuel And Shall Use Good Combustion Operating Practices	0.03	lb/MMBtu		Not Comparable - Unit utilizes oxidation catalyst to meet VOC LAER limit.
MD-0036	Dominion	MD	3/10/2006	Fuel Gas Process Heater			Good Combustion Practices	143.0	ppmvd		
MD-0040	CPV St Charles	MD	11/12/2008	Heater	1.7	MMBtu/hr		0.08	lb/MMBtu		
MN-0070	Minnesota Steel Industries, LLC	MN	9/7/2007	Small Boilers & Heaters	99.0	MMBtu/hr		0.1	lb/MMBtu	1 Hour Average	
NE-0026	Nucor Steel Division	NE	6/22/2004	NNII Bilet Post-Heater	6.8	MMBtu/hr		0.01	lb/MMBtu		Not Comparable - RBLC specifies limit as Case-by-Case, not BACT
NE-0043	Natureworks, LLC	NE	4/29/2008	Hot Oil Heater	75	MMBtu/hr	Good Combustion Practices				
NV-0042	Capital Cabinet Corporation	NV	11/05/2004	Fuel Combustion	8.8	MMBtu/hr	Use Of Natural Gas As The Only Fuel For All Combustion Units	0.4	t/mo	Per Calendar Month	
NV-0050	MGM Mirage	NV	11/30/2009	Water Heaters	2	MMBtu/hr	Limiting The Fuel To Natural Gas Only And Good Combustion Practices	0.04	lb/MMBtu		Not Comparable - LAER Limit
OH-0355	General Electric Aviation, Evendale Plant	OH	5/7/2013	4 Indirect-Fired Air Preheaters				0.2	lb/MMBtu		
OK-0128	Mid American Steel Rolling Mill	OK	9/8/2008	Ladle Pre-Heater And Refractory Drying			Natural Gas Fuel	0.08	lb/MMBtu		
OK-0129	Chouteau Power Plant	OK	1/23/2009	Fuel Gas Heater (H2O Bath)	18.8	MMBtu/hr		0.4	lb/hr		
OK-0134	Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheaters No. 1	20	MMBtu/hr	Good Combustion Practices	1.65	lb/hr	1-Hr, 8-Hr	
OK-0134	Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheater No. 3	20	MMBtu/hr	Good Combustion	1.65	lb/hr	1-Hr/8-Hr	
OK-0135	Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheaters #1, #3, And #4	20	MMBtu/hr	Good Combustion Practices.	1.65	lb/hr	1-Hour/8-Hour	
OK-0136	Ponca City Refinery	OK	2/9/2009	TB-1, TB-2, TB-3	95	MMBtu/hr	Ultra-Low NOx Burners And Good Combustion Practice; 0.04 Lb/Mmbtu	3.80	lb/hr	365-Day Rolling Average	
SC-0111	Flakeboard America Limited - Bennettsville MDF	SC	12/22/2009	Face Primary Dryer	45	MMBtu/hr	Good Combustion Practices And Natural Gas As Fuel				
SC-0111	Flakeboard America Limited - Bennettsville MDF	SC	12/22/2009	Core Primary Dryer	45	MMBtu/hr	Good Combustion Practices And Natural Gas As Fuel				
SC-0112	Nucor Steel - Berkeley	SC	5/5/2008	Tunnel Furnace Burners	58	MMBtu/hr	Natural Gas Combustion With Good Combustion Practices Per Manufacturer Guidance.	0.08	lb/MMBtu		
SC-0114	GP Allendale LP	SC	11/25/2008	Propane Vaporizers (ID15)	5	MMBtu/hr	Tune-Ups And Inspections Will Be Performed As Outlined In The Good Management Practice Plan.	0.17	lb/hr		
SC-0114	GP Allendale LP	SC	11/25/2008	Natural Gas Space Heaters - 14 Units (ID18)	20.89	MMBtu/hr		1.67	lb/hr		

Table D-13. Fuel Gas Heater RBLC Search Results - CO

ID	Facility/Company	State	Permit Issuance Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
SC-0114	GP Allendale LP	SC	11/25/2008	75 Million Btu/Hr Backup Thermal Oil Heater	75	MMBtu/hr	Pollution Prevention Of Co Emissions Will Occur By Performing Scheduled Tune-Ups And Inspections As Outlined In The Good Management Practice Plan.	6.00	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	75 Million Btu/Hr Backup Thermal Oil Heater	75	MMBtu/hr	Tune-Ups And Inspections Will Be Performed As Outlined The Good Management Practice Plan.	6.00	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	Propane Vaporizers (ID14)	5	MMBtu/hr	Tune-Ups And Inspections Will Be Performed As Outlined In The Good Management Practice Plan.	0.17	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	Natural Gas Space Heaters - 14 Units (ID17)	20.89	MMBtu/hr		1.67	lb/hr		
WA-0301	BP Cherry Point Refinery	WA	4/20/2005	Process Heater, IHT	13.0	MMBtu/hr	Good Combustion Practices	70.0	ppm	7% O2, 24 Hr Ave	
WI-0223	Louisiana-Pacific Hayward	WI	6/17/2004	Thermal Oil Heater, GTS Energy, S31, B31	32	MMBtu/hr	Use Of Natural Gas / Distillate Oil, W/ Restriction On Oil Usage	2.70	lb/hr		
WI-0223	Louisiana-Pacific Hayward	WI	6/17/2004	Thermal Oil Heater, GTS Energy, S32, B32	32	MMBtu/hr	Use Of Natural Gas / Distillate Oil, W/ Restriction On Oil Usage	2.70	lb/hr		
WI-0227	Port Washington Generating Station	WI	10/13/2004	Gas Heater (P06, S06)	10.0	MMBtu/hr	Natural Gas Fuel	0.5	lb/hr		
WI-0228	WPS - Weston Plant	WI	10/19/2004	Natural Gas Station Heater 1 And 2	0.75	MMBtu/hr	Natural Gas	0.06	lb/hr		
WY-0066	Medicine Bow IGL Plant	WY	3/4/2009	Gasification Preheater 2	21.0	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	Hourly	
WY-0066	Medicine Bow IGL Plant	WY	3/4/2009	Gasification Preheater 3	21.0	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	Hourly	
WY-0066	Medicine Bow IGL Plant	WY	3/4/2009	Gasification Preheater 4	21.0	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	Hourly	
WY-0066	Medicine Bow IGL Plant	WY	3/4/2009	Gasification Preheater 5	21.0	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	Hourly	
WY-0066	Medicine Bow IGL Plant	WY	3/4/2009	Gasification Preheater 1	21.0	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	Hourly	
WY-0067	Echo Springs Gas Plant	WY	4/1/2009	Hot Oil Heater S38	84	MMBtu/hr	Good Combustion Practices	0.02	lb/MMBtu		Not Comparable - Limit is for hot oil heater.
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP07)	16.1	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	3-Hour Average	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP08)	16.1	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	3-Hour Average	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP09)	16.1	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	3-Hour Average	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP10)	16.1	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	3-Hour Average	
WY-0070	Cheyenne Prairie Generating Station	WY	8/28/2012	Inlet Air Heater (EP11)	16.1	MMBtu/hr	Good Combustion Practices	0.1	lb/MMBtu	3-Hour Average	

Table D-14. Fuel Gas Heater RBLC Search Results - VOC

ID	Facility/Company	State	Permit Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
CO-0058	Cheyenne Station	CO	6/12/2004	Heaters	45.0	MMBtu/hr	Good Combustion Practices	0.02	lb/MMBtu	1-Hr Average	
IA-0088	ADM Corn Processing - Cedar Rapids	IA	6/29/2007	Indirect-Fired DDGS Dryer	93.7	MMBtu/hr	Route Process Off-Gasses Through The Dryers Combustion Chamber	98	% reduction	Average Of 3 Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	0.001	lb/MMBtu	Average Of Three (3) Stack Test Runs	Not Comparable - Permit does not require performance testing to demonstrate compliance. Therefore, compliance with this BACT limit has not been demonstrated.
LA-0192	Crescent City Power	LA	6/6/2005	Fuel Gas Heaters (3)	19.0	MMBtu/hr	Good Combustion Practices	0.1	lb/hr	Hourly Maximum	
LA-0203	Oakdale OSB Plant	LA	6/13/2005	Auxiliary Thermal Oil Heater	66.5	MMBtu/hr	Use Of Natural Gas As Fuel And Good Combustion Practices	0.43	lb/hr	Hourly Maximum	
MD-0035	Dominion	MD	8/12/2005	Vaporization Heater			Natural Gas Combustion And A Catalytic Oxidation	0.002	lb/MMBtu		Not Comparable - Unit utilizes oxidation catalyst to meet VOC LAER limit.
MD-0036	Dominion	MD	3/10/2006	Fuel Gas Process Heater			Good Combustion Practices	143	ppmvd	3-Hour Average	
MD-0040	CPV St Charles	MD	11/12/2008	Heater	1.7	MMBtu/hr		0.005	lb/MMBtu		
NE-0026	Nucor Steel Division	NE	6/22/2004	NNII Bilet Post-Heater	6.8	MMBtu/hr		0.0055	lb/MMBtu		
NV-0050	MGM Mirage	NV	11/30/2009	Water Heaters	2.0	MMBtu/hr	Limiting The Fuel To Natural Gas Only And Good Combustion Practices	0.005	lb/MMBtu		
OH-0355	General Electric Aviation, Evendale Plant	OH	5/7/2013	4 Indirect-Fired Air Preheaters				0.005	lb/MMBtu		
OK-0128	Mid American Steel Rolling Mill	OK	9/8/2008	Ladle Pre-Heater And Refractory Drying			Natural Gas Fuel	0.006	lb/MMBtu		
OK-0129	Chouteau Power Plant	OK	1/23/2009	Fuel Gas Heater (H2O Bath)	18.8	MMBtu/hr		0.1	lb/hr		
OK-0134	Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheaters No. 1	20.0	MMBtu/hr	Good Combustion	0.11	lb/hr		
OK-0135	Pryor Plant Chemical	OK	2/23/2009	Nitric Acid Preheaters #1, #3, And #4	20	MMBtu/hr		0.11	lb/hr		
SC-0111	Flakeboard America Limited - Bennettsville MDF	SC	12/22/2009	Face Primary Dryer	45.0	MMBtu/hr	Good Combustion Practices And Natural Gas As Fuel				
SC-0111	Flakeboard America Limited - Bennettsville MDF	SC	12/22/2009	Core Primary Dryer	45.0	MMBtu/hr	Good Combustion Practices And Natural Gas As Fuel				
SC-0112	Nucor Steel - Berkeley	SC	5/5/2008	Tunnel Furnace Burners	58	MMBtu/hr	Natural Gas Combustion With Good Combustion Practices Per Manufacturer Guidance	0.0055	lb/MMBtu		
SC-0114	GP Allendale LP	SC	11/25/2008	Propane Vaporizers (ID15)	5.0	MMBtu/hr	Tune-Ups And Inspections Will Be Performed As Outlined In The Good Management Practice Plan.	0.04	lb/hr		
SC-0114	GP Allendale LP	SC	11/25/2008	Natural Gas Space Heaters - 14 Units (ID18)	20.9	MMBtu/hr		0.11	lb/hr		
SC-0114	GP Allendale LP	SC	11/25/2008	75 Million Btu/Hr Backup Thermal Oil Heater	75.0	MMBtu/hr	Good Combustion Practices Will Be Used As Control For VOC Emissions	0.39	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	75 Million Btu/Hr Backup Thermal Oil Heater	75	MMBtu/hr	Good Combustion Practices Will Be Used As Control For VOC Emissions.	0.39	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	Propane Vaporizers (ID14)	5	MMBtu/hr	Tune-Ups And Inspections Will Be Performed As Outlined In The Good Management Practice Plan.	0.04	lb/hr		
SC-0115	GP Allendale LP	SC	2/10/2009	Natural Gas Space Heaters - 14 Units	20.89	MMBtu/hr		0.11	lb/hr		
WI-0223	Louisiana-Pacific Hayward	WI	6/17/2004	Thermal Oil Heater, Gts Energy, S31, B31	32.0	MMBtu/hr	Use Of Natural Gas / Distillate Oil, W/ Restriction On Oil Usage	0.18	lb/hr		
WI-0223	Louisiana-Pacific Hayward	WI	6/17/2004	Thermal Oil Heater, Gts Energy, S32, B32	32.0	MMBtu/hr	Use Of Natural Gas / Distillate Oil, W/ Restriction On Oil Usage	0.18	lb/hr		
WI-0227	Port Washington Generating Station	WI	10/13/2004	Gas Heater (P06, S06)	10	MMBtu/hr	Natural Gas Fuel	0.06	lb/hr		
WI-0228	WPS - Weston Plant	WI	10/19/2004	B63, S63; B64, S64 - Natural Gas Station Heater 1 And 2	0.8	MMBtu/hr	Natural Gas	0.004	lb/hr		
WY-0067	Echo Springs Gas Plant	WY	4/1/2009	Hot Oil Heater S38	84	MMBtu/hr	Good Combustion Practices	0.02	lb/MMBtu		

Table D-15. Fuel Gas Heater RBLC Search Results - GHGs

ID	Facility/Company	State	Permit Date	Process Type	Capacity	Units	Control Type	Limit	Limit Units	Avg. Period	Note(s)
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	117	lb/MMBtu	Average Of Three (3) Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	0.002	lb CH4/MMBtu	Average Of Three (3) Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	0.001	lb N2O/MMBtu	Average Of Three (3) Stack Test Runs	
IA-0106	CF Industries Nitrogen, LLC - Port Neal Nitrogen Complex	IA	7/12/2013	Startup Heater	58.8	MMBtu/hr	Good Operating Practices & Use Of Natural Gas	345	tpy	Rolling Twelve (12) Month Total	
OH-0355	General Electric Aviation, Evendale Plant	OH	5/7/2013	4 Indirect-Fired Air Preheaters				74,000	tpy	Total For 2 Test Cells And 4 Preheaters	

Table D-16. Cost Estimate for CO_2 Pipeline

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline[1]	200	miles
Average Diameter of Pipeline[2 3]	12	inches
CO_2 emissions from NGCC combustion turbines (2)[4]	2,378,862	tpy
CO_2 Capture Efficiency[5]	90	%
Captured CO_2	2,140,976	tpy

CO_2 Pipeline Cost Estimate[6]

Cost Type	Units	Equation[7]	Cost[7]
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 * L * (330.5 * D² + 686.7 * D + 26,960)	$34,323,031
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 * L * (343.2 * D² + 2,074 * D + 170,013)	$101,456,572
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 * L * (8,417 * D + 7,234)	$38,392,548
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 * L * (577 * D +29,788)	$9,905,097
Other Capital Costs			
CO_2 Surge Tank	$	$1,150,636	$1,286,519
Pipeline Control System	$	$110,632	$123,697
Operation & Maintenance (O&M)			
Fixed O&M	$/mile/yr	$8,632	$1,930,276
		Total Pipeline Cost	**$187,417,739**

Amortized Cost Calculation - CO_2 Pipeline

Equipment Life[9]	20	years
Interest rate[10 11]	7.00	%
Capital Recovery Factor (CRF)[12]	0.09	
Total Pipeline Installation Cost (TCI)	$185,487,462	Pipeline Costs + Other Capital Costs
Amortized Installation Cost (TCI * CRF)	$17,508,704	per year
Amortized Installation + O&M Cost	$19,438,981	per year
CO_2 Transferred	2,140,976	tpy
Amortized control cost[13]	**9**	**$/ton**

[1] Distance between the Green River Generating Station in Central City, Kentucky, to the nearest potential CO_2 storage site in Decatur, Illinois.
[2] Carbon Capture and Sequestration Technologies Program, Massachusetts Institute of Technology. (2006, October).*Carbon Management GIS: CO_2 Pipeline Transport Cost Estimation.* Retrieved from http://sequestration.mit.edu/energylab/uploads/AaKal/transport_tool_paper-draft22Aug07_liw.doc
[3] Average Diameter of Pipeline per cited document, based on a CO_2 flow rate between 1.13 and 3.25 Mt/yr.
[4] The worst-case (i.e., lowest) PTE for CO_2 for all NGCC combustion turbine options, based on the worst-case scenario (i.e., with the lowest potential CO_2 emissions) of operation with maximum startups and shutdowns, is used conservatively.
[5] Rubin, E.S. & Haibo, Z. (2012, February). The Cost of Carbon Capture and Storage for Natural Gas Combined Cycle Power Plants.*Environmental Science & Technology, 46, 3077.*
[6] U.S. Department of Energy National Energy Technology Laboratory. (2010, March).*Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs.* Retrieved from http://www.netl.doe.gov/File Library/Research/Energy Analysis/Publications/DOE-NETL-2010-1447-QGESSCarbonDioxideTransportStorageCosts.pdf
[7] Equations based on June 2007 dollars, per cited document. Costs for the current analysis have been adjusted to 2013 dollars based on the U.S. Department of Labor, Bureau of Labor Statistics' Consumer Price Index (CPI), available at ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt
[9] Equipment life based on engineering estimate.
[10] U.S. EPA Office of Air Quality Planning and Standards. (2002, January).*EPA Air Pollution Control Cost Manual* (6th ed.). Retrieved from http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=910118CI.PDF
[11] Interest rate conservatively set at 7 percent per cited document.
[12] Capital Recovery Factor = Interest Rate (%) * (1+ Interest Rate (%)) ^ Equipment Life) / ((1 + Interest Rate (%)) ^ Equipment Life - 1)
[13] Cost estimate conservatively excludes capital and O&M costs associated with compression and processing equipment.

Table D-17. Carbon Capture and Sequestration (CCS) - Total Cost Estimate

Carbon Capture and Sequestration (CCS) System Component	Cost Factor[1,2,3] ($/ton CO_2)	Annual Throughput (tpy CO_2)	Total Annual Cost
CO_2 Capture and Compression System	$93.58	2,140,976	$200,359,140
CO_2 Transport Facilities (Pipeline)	$9.08	2,140,976	$19,438,981
CO_2 Storage System[4]	$0.39	2,140,976	$843,617
Total Cost:	$103.06	-	$220,641,738

Amortized Cost Calculation - Proposed NGCC Plant Project Capital Cost

Equipment Life[5]	20	years
Interest rate[6 7]	7.00	%
Capital Recovery Factor (CRF)[8]	0.09	
Total Capital Cost for the Proposed NGCC Plant Project	$700,000,000	equipment & control costs
O & M Cost (O&M)	$14,500,000	for equipment life
Amortized Installation Cost (TCI *CRF)	$66,075,048	per year
Amortized O & M Cost (O&M *CRF)	$1,368,697	per year
Amortized Installation + O&M Cost	**$67,443,745**	**per year (Project Capital Cost)**

Ratio of CCS Cost to Project Capital Cost on Annual Basis	**3.27**

[1] Interagency Task Force on Carbon Capture and Storage. (2010, August).*Report of the Interagency Task Force on Carbon Capture.* Retrieved from http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

[2] The cited document provides a range of costs for CO_2 transport and storage facilities. The Cost Factors used in the current analysis are conservatively based on the low end of each cost range.

[3] Cost Factors were converted from $/tonne and 2009 dollars in the source document to $/ton and 2013 dollars (based on the Consumer Price Index) for the current analysis.

[4] The Cost Factor for a CO_2 Storage System is limited to capital and operational costs and does not include potential costs associated with long-term liability.

[5] Equipment life based on engineering estimate.

[6] U.S. EPA, Office of Air Quality Planning and Standards. (2002, January).*EPA Air Pollution Control Cost Manual* (6th ed.). Retrieved from http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=910118CI.PDF

[7] Interest rate conservatively set at 7 percent per cited document.

[8] Capital Recovery Fraction = Interest Rate (%) * (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

Table D-18. Cost Estimate for Oxidation Catalyst to Control CO Emissions from Auxiliary Boiler

Capital Investment Cost Estimate - Oxidation Catalyst

Direct Costs[1,2]	
Purchased Equipment Cost	
Base Equipment Cost[3]	$82,594
Instrumentation (10% of Base Equipment Cost)	$8,259
Sales Tax (6% in Kentucky)	$4,956
Freight (5% of Base Equipment Cost)	$4,130
Total Purchased Equipment Cost (PEC)	**$99,939**
Direct Installation Costs	
Foundation and supports (8% of PEC)	$7,995
Handling and erection (14% of PEC)	$13,991
Electrical (4% of PEC)	$3,998
Piping (2% of PEC)	$1,999
Insulation for ductwork (1% of PEC)	$999
Painting (1% of PEC)	$999
Total Direct Installation Cost (DIC)	**$29,982**
Total Direct Costs (DC)	**$129,920**
Indirect Costs (Installation)[1,2]	
Engineering (10% of PEC)	$9,994
Construction and field expenses (5% of PEC)	$4,997
Contractor fees (10% of PEC)	$9,994
Start-up (2% of PEC)	$1,999
Performance test (1% of PEC)	$999
Contingencies (3% of PEC)	$2,998
Total Indirect Costs (IC)	**$30,981**
Total Capital Investment (TCI = DCC + ICC)	**$160,901**

Amortized Cost Calculation - Oxidation Catalyst for Control of CO

Direct Annual Costs	
Operating Labor[4]	
Operator (0.5 hr/shift, 3 shifts/day, 183 days/yr for 50% utilization @ $30.20/man-hr)	$8,289
Supervision (15% of Operator)	$1,243
Maintenance[4]	
Labor (0.5 hr/shift, 3 shifts/day, 183 days/yr for 50% utilization @ $19.81/man-hr)	$5,437
Material (100% of Maintenance Labor)	$5,437
Catalyst Cost[5]	$24,501
Total Direct Annual Costs (DAC)	**$44,906**
Indirect Annual Costs	
Overhead (60% of Operating Labor and Maintenance)	$12,243
Administrative Charges (2% of TCI)	$3,218
Property Taxes (1% of TCI)	$1,609
Insurance (1% of TCI)	$1,609
Capital Recovery (CRF x TCI)[6]	$22,909
Total Indirect Annual Costs (IAC)	**$41,588**
Total Annualized Cost (TAC = DAC + IAC)	**$86,495**

Cost Effectiveness Summary

Annual Control Cost	**$86,495**
Pollutant to be Removed [CO] (tpy)[7]	**29.5**
Control Cost Effectiveness ($/ton)	**$2,929**

[1] U.S. EPA, Office of Air Quality Planning and Standards. (2002, January). *EPA Air Pollution Control Cost Manual* (6th ed.). Retrieved from http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=910118CI.PDF

[2] Per Section 3.2, Chapter 2, *Table 2.8: Capital Cost Factors for Thermal and Catalytic Incinerators* and *Table 2.10 Annual Costs for Thermal and Catalytic Incinerators Example Problem* in the cited document.

[3] Equipment cost (in 2009 dollars) per PSD application (05040027) for Taylorville Energy Center submitted to the Illinois Environmental Protection Agency (IEPA) in November 2010. Costs adjusted to 2013 dollars based on the U.S. Department of Labor Consumer Price Index (CPI), and scaled using sixth-tenths power law to adjust for airflow.

[4] Labor rates per U.S Department of Labor, Bureau of Labor Statistics May 2012 State Occupational Employment and Wage Estimates for Kentucky (http://www.bls.gov/oes/current/oes_ky), for Occupation Codes 51-8013 (Power Plant Operators) and 49-0000 (Installation, Maintenance, and Repair Occupations).

[5] Catalyst costs based upon the following data:

Catalyst Cost:	$55,867
Catalyst Disposal Cost:	$5,079
Sales Tax (6% in Kentucky)	$3,352
Capital Recovery Factor	0.381

Catalyst costs per PSD application (05040027) for Taylorville Energy Center submitted to IEPA in November 2010. Costs adjusted to 2013 dollars based on the U.S. Department of Labor CPI and scaled using sixth-tenths power law to adjust for difference in airflow. Capital Recovery Factor for catalyst calculated based on 3 years at 7 percent interest.

[6] Capital Recovery Factor calculated based on 10 years at 7 percent interest.

[7] Based on a 90 percent control efficiency for CO.

Table D-19. Cost Estimate for Oxidation Catalyst to Control VOC Emissions from Auxiliary Boiler

Capital Investment Cost Estimate - Oxidation Catalyst

Direct Costs[1,2]	
Purchased Equipment Cost	
Base Equipment Cost[3]	$82,594
Instrumentation (10% of Base Equipment Cost)	$8,259
Sales Tax (6% in Kentucky)	$4,956
Freight (5% of Base Equipment Cost)	$4,130
Total Purchased Equipment Cost (PEC)	**$99,939**
Direct Installation Costs	
Foundation and supports (8% of PEC)	$7,995
Handling and erection (14% of PEC)	$13,991
Electrical (4% of PEC)	$3,998
Piping (2% of PEC)	$1,999
Insulation for ductwork (1% of PEC)	$999
Painting (1% of PEC)	$999
Total Direct Installation Cost (DIC)	**$29,982**
Total Direct Costs (DC)	**$129,920**
Indirect Costs (Installation)[1,2]	
Engineering (10% of PEC)	$9,994
Construction and field expenses (5% of PEC)	$4,997
Contractor fees (10% of PEC)	$9,994
Start-up (2% of PEC)	$1,999
Performance test (1% of PEC)	$999
Contingencies (3% of PEC)	$2,998
Total Indirect Costs (IC)	**$30,981**
Total Capital Investment (TCI = DCC + ICC)	**$160,901**

Amortized Cost Calculation - Oxidation Catalyst for Control of VOC

Direct Annual Costs	
Operating Labor[4]	
Operator (0.5 hr/shift, 3 shifts/day, 183 days/yr for 50% utilization @ $30.20/man-hr)	$8,289
Supervision (15% of Operator)	$1,243
Maintenance[4]	
Labor (0.5 hr/shift, 3 shifts/day, 183 days/yr for 50% utilization @ $19.81/man-hr)	$5,437
Material (100% of Maintenance Labor)	$5,437
Catalyst Cost[5]	$24,501
Total Direct Annual Costs (DAC)	**$44,906**
Indirect Annual Costs	
Overhead (60% of Operating Labor and Maintenance)	$12,243
Administrative Charges (2% of TCI)	$3,218
Property Taxes (1% of TCI)	$1,609
Insurance (1% of TCI)	$1,609
Capital Recovery (CRF x TCI)[6]	$22,909
Total Indirect Annual Costs (IAC)	**$41,588**
Total Annualized Cost (TAC = DAC + IAC)	**$86,495**

Cost Effectiveness Summary

Annual Control Cost	**$86,495**
Pollutant to be Removed [VOC] (tpy)[7]	**1.2**
Control Cost Effectiveness ($/ton)	**$71,694**

[1] U.S. EPA, Office of Air Quality Planning and Standards. (2002, January). *EPA Air Pollution Control Cost Manual* (6th ed.). Retrieved from http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=910118CI.PDF

[2] Per Section 3.2, Chapter 2, *Table 2.8: Capital Cost Factors for Thermal and Catalytic Incinerators* and *Table 2.10 Annual Costs for Thermal and Catalytic Incinerators Example Problem* in the cited document.

[3] Equipment cost (in 2009 dollars) per PSD application (05040027) for Taylorville Energy Center submitted to the Illinois Environmental Protection Agency (IEPA) in November 2010. Costs adjusted to 2013 dollars based on the U.S. Department of Labor Consumer Price Index (CPI), and scaled using sixth-tenths power law to adjust for airflow.

[4] Labor rates per U.S Department of Labor, Bureau of Labor Statistics May 2012 State Occupational Employment and Wage Estimates for Kentucky (http://www.bls.gov/oes/current/oes_ky), for Occupation Codes 51-8013 (Power Plant Operators) and 49-0000 (Installation, Maintenance, and Repair Occupations).

[5] Catalyst costs based upon the following data:

Catalyst Cost:	$55,867
Catalyst Disposal Cost:	$5,079
Sales Tax (6% in Kentucky)	$3,352
Capital Recovery Factor	0.381

Catalyst costs per PSD application (05040027) for Taylorville Energy Center submitted to IEPA in November 2010. Costs adjusted to 2013 dollars based on the U.S. Department of Labor CPI and scaled using sixth-tenths power law to adjust for difference in airflow. Capital Recovery Factor for catalyst calculated based on 3 years at 7 percent interest.

[6] Capital Recovery Factor calculated based on 10 years at 7 percent interest.

[7] Based on a 90 percent control efficiency for VOC.

APPENDIX E: CAM PLANS

E. NGCC COMBUSTION TURBINES – CO CAM PLAN

This section contains the CO CAM plans for the proposed NGCC combustion turbines. Each combustion turbine will use the same CO emission control and monitoring methods. Because the same CAM plan applies to each combustion turbine, the CAM plans for each have been combined into a single CAM plan in this section.

E.1. CO CAM BACKGROUND

Table E-1. Emission Unit and CO Controls

Source:	Kentucky Utilities Company/Green River Generating Station Central City, Kentucky Source ID 21-177-00001 (Agency Interest 3228)
Emission Unit Identification:	Emission Unit 09, Emission Point S09 Emission Unit 10, Emission Point S10
Description:	Natural gas-fired combined cycle combustion turbines Option A – 2,582 MMBtu/hr (per turbine) Option B – 2,868 MMBtu/hr (per turbine) Option C – 2,902 MMBtu/hr (per turbine)
CO Control:	Oxidation Catalyst

Table E-2. Applicable Regulations and Potential CO Emissions

Pollutant:	CO
Regulation:	401 KAR 51:017
Emission Limit:	EU09 (Proposed limit): 2.0 ppmvd at 15% O_2 based on a 3-hr average during normal operation EU10 (Proposed limit): 2.0 ppmvd at 15% O_2 based on a 3-hr average during normal operation
Pre-Controlled Emissions:	>100 tpy (per turbine) Estimated pre-controlled CO emissions for each combustion turbine are based on manufacturer emissions data.
Post-Controlled Emissions:	<100 tpy (per turbine, Option A) >100 tpy (per turbine, Options B and C) Estimated post-controlled CO emissions for each combustion turbine are based on manufacturer emissions data.
CAM Designation:	Small PSEU (Option A) Large PSEU (Options B and C)

E.2. CAM APPLICABILITY FOR CO

Each combustion turbine will be subject to a CO BACT limit under 401 KAR 51:017. Pursuant to 40 CFR 64.2(a), because each combustion turbine will use an oxidation catalyst to achieve compliance with the proposed CO BACT limit and potential pre-controlled CO emissions exceed 100 tpy (i.e., per combustion turbine), CAM will apply to each of the combustion turbines for CO. Proposed BACT limits listed in Table E-2 apply during normal operation only; therefore, the requirements of CAM are applicable only during normal operation of the combustion turbines.

E.3. MONITORING APPROACH FOR CO

CO emissions are a byproduct of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. KU will use an oxidation catalyst to control CO emissions from each combustion turbine. KU proposes to use temperature monitoring as the primary indicator of oxidation catalyst performance.

The monitoring approach outlined in Table E-3 will provide on-going assurance of compliance with the proposed CO BACT limit for each combustion turbine. Specific details regarding each monitoring method and monitoring performance criteria for each indicator are provided in Table E-4.

Because Kentucky utilizes a combined construction and Title V permitting program, KU is unable to complete initial compliance tests prior to the submittal of a Title V permit application with the requisite CAM plans. Therefore, certain aspects of the proposed monitoring approach cannot be finalized or implemented until start-up and initial performance testing are completed.

Table E-3. Oxidation Catalyst - Monitoring Approach Summary for CO Controls

Method	Indicator Parameter	Range	Frequency
Temperature Monitoring	Oxidation Catalyst Operating Temperature	Value provided by catalyst vendor	Continuous (Reading every 15 minutes)

Table E-4. Temperature Monitoring Criteria for CO Controls

Indicator	Oxidation Catalyst Operating Temperature (°F)
Measurement Approach	The temperature of the oxidation catalyst will be continuously recorded (data captured at least once every 15 minutes).
Indicator Range	An excursion will be defined to occur if the 3-hour average oxidation catalyst operating temperature falls below the value provided by the catalyst vendor during normal operation.
Corrective Actions	In response to an excursion, KU will complete an inspection of the oxidation catalyst system to determine the cause and will correct any revealed performance issues in the most expedient manner possible.
Data Representativeness	Temperature will be monitored at the catalyst bed inlet. Accuracy of temperature monitoring will be approximately ±1.5 °F or the industry standard.
Verification of Operational Status	KU will follow the installation, calibration, and startup procedures recommended by the manufacturer.
QA/QA Practices and Criteria	The monitoring device will be periodically calibrated in accordance with the manufacturer's recommended practices.
Monitoring Frequency	Temperature data will be captured at least once every 15 minutes when the system is in use.
Data Collection Procedure	The monitoring device will be equipped with a process logic controller that will capture readings electronically and send them to a data storage drive, where the information can be monitored and trended.
Averaging Period	Up to four readings (four 15-minute intervals) each hour and a minimum of two readings (two 15-minute intervals) will be averaged to yield an hourly average temperature for each operating hour.
Recordkeeping	➤ Electronic archives of temperature data. ➤ Causes and corrective actions taken associated with any excursions, noted in the maintenance log. ➤ Documentation and records of monitoring device calibrations.
Reporting	A summary of temperature readings and a tally of excursions will be provided in the Title V semiannual monitoring reports.

E.4. MONITORING APPROACH JUSTIFICATION

Rationale for Performance Indicator Selection

Monitoring of the oxidation catalyst operating temperature provides direct confirmation that the oxidation catalyst system is in operation. Because other variables associated with the operation of the oxidation catalyst system (e.g., size and characteristics of the catalyst bed) are relatively fixed, maintaining the operating temperature at a value that exceeds the lower threshold value specified by the manufacturer or established based on the most recent compliance stack test will help to ensure that CO emissions are kept to levels below the proposed BACT limit.

Rationale for Indicator Range Selection

Because the specific vendor and design for the oxidation catalyst system have not yet been selected and an initial performance test has not yet been completed, it is not possible to establish a lower threshold for the oxidation catalyst operating temperature. KU will comply with the initial CO compliance testing schedule specified in the issued Title V permit. KU anticipates that testing will occur within 180 days of start-up of the oxidation catalyst system. During the initial performance test, temperature will be continuously monitored simultaneous with the CO emissions testing, and monitoring data will be collected to establish an appropriate lower threshold for the oxidation catalyst operating temperature.

E. NGCC COMBUSTION TURBINES – VOC CAM PLAN

This section contains the VOC CAM plans for the proposed NGCC combustion turbines. Each combustion turbine will use the same VOC emission control and monitoring methods. Because the same CAM plan applies to each combustion turbine, the CAM plans for each have been combined into a single CAM plan in this section.

E.5. VOC CAM BACKGROUND

Table E-5. Emission Unit and VOC Controls

Source:	Kentucky Utilities Company/Green River Generating Station Central City, Kentucky Source ID 21-177-00001 (Agency Interest 3228)
Emission Unit Identification:	Emission Unit 09, Emission Point S09 Emission Unit 10, Emission Point S10
Description:	Natural gas-fired combined cycle combustion turbines Option A – 2,582 MMBtu/hr (per turbine) Option B – 2,868 MMBtu/hr (per turbine) Option C – 2,902 MMBtu/hr (per turbine)
VOC Control:	Oxidation Catalyst

Table E-6. Applicable Regulations and Potential VOC Emissions

Pollutant:	VOC
Regulation:	401 KAR 51:017
Emission Limit:	EU09 (Proposed limit): 2.0 ppmvd at 15% O_2 based on a 3-hr average during normal operation EU10 (Proposed limit): 2.0 ppmvd at 15% O_2 based on a 3-hr average during normal operation
Pre-Controlled Emissions:	>100 tpy (per turbine, Option B) Estimated pre-controlled VOC emissions for each combustion turbine are based on manufacturer emissions data.
Post-Controlled Emissions:	>100 tpy (per turbine, Option B) Estimated post-controlled VOC emissions for each combustion turbine are based on manufacturer emissions data.
CAM Designation:	Large PSEU (Option B)

E.6. CAM APPLICABILITY FOR VOC

Each combustion turbine will be subject to a VOC BACT limit under 401 KAR 51:017. Pursuant to 40 CFR 64.2(a), because each combustion turbine will use an oxidation catalyst to achieve compliance with the proposed VOC BACT limit and potential pre-controlled VOC emissions exceed 100 tpy (i.e., per combustion turbine) for Option B, CAM will apply to each of the combustion turbines for VOC if Option B is selected. Proposed BACT limits listed in Table E-6 apply during normal operation only; therefore, the requirements of CAM are applicable only during normal operation of the combustion turbines if Option B is selected.

Potential pre-controlled VOC emissions are less than 100 tpy (i.e., per combustion turbine) for Options A and C; therefore, the requirements of CAM will not be applicable to the combustion turbines for VOC if one of these turbine options is selected.

E.7. MONITORING APPROACH FOR VOC

VOC emissions are a byproduct of incomplete combustion. VOCs can encompass a wide spectrum of volatile organic compounds, some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. KU will use an oxidation catalyst to control VOC emissions from each combustion turbine. KU proposes to use temperature monitoring as the primary indicator of oxidation catalyst performance.

The monitoring approach outlined in Table E-7 will provide on-going assurance of compliance with the proposed VOC BACT limit for each combustion turbine. Specific details regarding each monitoring method and monitoring performance criteria for each indicator are provided in Table E-8.

Because Kentucky utilizes a combined construction and Title V permitting program, KU is unable to complete initial compliance tests prior to the submittal of a Title V permit application with the requisite CAM plans. Therefore, certain aspects of the proposed monitoring approach cannot be finalized or implemented until start-up and initial performance testing are completed.

Table E-7. Oxidation Catalyst - Monitoring Approach Summary for VOC Controls

Method	Indicator Parameter	Range	Frequency
Temperature Monitoring	Oxidation Catalyst Operating Temperature	Value provided by catalyst vendor	Continuous (Reading every 15 minutes)

Table E-8. Temperature Monitoring Criteria for VOC Controls

Indicator	Oxidation Catalyst Operating Temperature (°F)
Measurement Approach	The temperature of the oxidation catalyst will be continuously recorded (data captured at least once every 15 minutes).
Indicator Range	An excursion will be defined to occur if the 3-hour average oxidation catalyst operating temperature falls below the value provided by the catalyst vendor during normal operation.
Corrective Actions	In response to an excursion, KU will complete an inspection of the oxidation catalyst system to determine the cause and will correct any revealed performance issues in the most expedient manner possible.
Data Representativeness	Temperature will be monitored at the catalyst bed inlet. Accuracy of temperature monitoring will be approximately ±1.5 °F or the industry standard.
Verification of Operational Status	KU will follow the installation, calibration, and startup procedures recommended by the manufacturer.
QA/QA Practices and Criteria	The monitoring device will be periodically calibrated in accordance with the manufacturer's recommended practices.
Monitoring Frequency	Temperature data will be captured at least once every 15 minutes when the system is in use.
Data Collection Procedure	The monitoring device will be equipped with a process logic controller that will capture readings electronically and send them to a data storage drive, where the information can be monitored and trended.
Averaging Period	Up to four readings (four 15-minute intervals) each hour and a minimum of two readings (two 15-minute intervals) will be averaged to yield an hourly average temperature for each operating hour.
Recordkeeping	➤ Electronic archives of temperature data. ➤ Causes and corrective actions taken associated with any excursions, noted in the maintenance log. ➤ Documentation and records of monitoring device calibrations.
Reporting	A summary of temperature readings and a tally of excursions will be provided in the Title V semiannual monitoring reports.

E.8. MONITORING APPROACH JUSTIFICATION

Rationale for Performance Indicator Selection

Monitoring of the oxidation catalyst operating temperature provides direct confirmation that the oxidation catalyst system is in operation. Because other variables associated with the operation of the oxidation catalyst system (e.g., size and characteristics of the catalyst bed) are relatively fixed, maintaining the operating temperature at a value that exceeds the lower threshold value specified by the manufacturer or established based on the most recent compliance stack test will help to ensure that VOC emissions are kept to levels below the proposed BACT limit.

Rationale for Indicator Range Selection

Because the specific vendor and design for the oxidation catalyst system have not yet been selected and an initial performance test has not yet been completed, it is not possible to establish a lower threshold for the oxidation catalyst operating temperature. KU will comply with the initial VOC compliance testing schedule specified in the issued Title V permit. KU anticipates that testing will occur within 180 days of start-up of the oxidation catalyst system. During the initial performance test, temperature will be continuously monitored simultaneous with the VOC emissions testing, and monitoring data will be collected to establish an appropriate lower threshold for the oxidation catalyst operating temperature.

APPENDIX F: MODELING FILES ON CD

The CD included with this appendix contains all input and output data files used to generate the results from the air quality analyses presented in Sections 7 and 8. The following section provides a description of the contents of each folder included on the enclosed CD.

AERMAP

- Contains the AERMAP input (.inp), output (.out), and receptor (.rec) files for the Significance Analysis modeling grids described in Section 7.1.

AERMET

- Raw Data – contains the raw data files from the BWG surface station and BNA upper air station that were used to create the model-ready meteorological files used in this analysis, including files containing 1-minute wind data for the BWG surface station.
- Input - Contains the AERMET input and output files that were used to create the model-ready meteorological files based on BWG surface characteristics.
- Model Ready - Contains the model ready surface (.sfc) and profile (.pfl) meteorological data files based on BWG surface characteristics that were utilized in this modeling analysis.
- AERSURFACE
  - BWG – contains the NLCD92 data (.tif) and AERSURFACE input (.inp) and output (.dat) files for BWG based on average (A), wet (W), and dry (D) moisture conditions.
  - GR– contains the NLCD92 (raw and modified) data (.tif) and AERSURFACE input (.inp) and output (.dat) files for the GRGS based on average (A) moisture conditions.

BPIP

- Contains the input, output, and summary files from the building downwash analysis. This analysis includes all modeled sources and buildings at the GRGS.

Class II

- CO –
  - 1HR –includes a zip file containing the AERMOD input (.ami), output (.aml), and plot (.plt) files for the 1-hour CO Significance Analysis.
  - 8HR –includes a zip file containing the AERMOD input (.ami), output (.aml), and plot (.plt) files for the 8-hour CO Significance Analysis.
- Air Toxics –
  - Non-Cancer – includes a zip file containing the AERMOD input (.ami), output (.aml), and plot (.plt) files for the non-cancerous air toxics analysis.
  - Cancer - includes a zip file containing the AERMOD input (.ami), output (.aml), and plot (.plt) files for the cancerous air toxics analysis.

APPENDIX G: SURFACE CHARACTERISTICS COMPARISON

Table G-1. Sector-by-Sector, Season-by-Season Surface Characteristics for GRGS at Average Moisture Conditions

Season	Wind Dir.	Albedo	Bowen Ratio	Surf. Roughness
Winter	0-30	0.160	0.590	0.044
Winter	30-60	0.160	0.590	0.064
Winter	60-90	0.160	0.590	0.032
Winter	90-120	0.160	0.590	0.026
Winter	120-150	0.160	0.590	0.047
Winter	150-180	0.160	0.590	0.033
Winter	180-210	0.160	0.590	0.039
Winter	210-240	0.160	0.590	0.528
Winter	240-270	0.160	0.590	0.651
Winter	270-300	0.160	0.590	0.687
Winter	300-330	0.160	0.590	0.528
Winter	330-360	0.160	0.590	0.214
Spring	0-30	0.140	0.360	0.056
Spring	30-60	0.140	0.360	0.080
Spring	60-90	0.140	0.360	0.039
Spring	90-120	0.140	0.360	0.034
Spring	120-150	0.140	0.360	0.062
Spring	150-180	0.140	0.360	0.044
Spring	180-210	0.140	0.360	0.051
Spring	210-240	0.140	0.360	0.836
Spring	240-270	0.140	0.360	0.856
Spring	270-300	0.140	0.360	0.871
Spring	300-330	0.140	0.360	0.766
Spring	330-360	0.140	0.360	0.299
Summer	0-30	0.170	0.340	0.076
Summer	30-60	0.170	0.340	0.090
Summer	60-90	0.170	0.340	0.047
Summer	90-120	0.170	0.340	0.092
Summer	120-150	0.170	0.340	0.168
Summer	150-180	0.170	0.340	0.125
Summer	180-210	0.170	0.340	0.095
Summer	210-240	0.170	0.340	1.149
Summer	240-270	0.170	0.340	1.001
Summer	270-300	0.170	0.340	1.014
Summer	300-330	0.170	0.340	0.983
Summer	330-360	0.170	0.340	0.355
Autumn	0-30	0.170	0.590	0.076
Autumn	30-60	0.170	0.590	0.090
Autumn	60-90	0.170	0.590	0.047
Autumn	90-120	0.170	0.590	0.092
Autumn	120-150	0.170	0.590	0.168
Autumn	150-180	0.170	0.590	0.125
Autumn	180-210	0.170	0.590	0.095
Autumn	210-240	0.170	0.590	1.149
Autumn	240-270	0.170	0.590	1.001
Autumn	270-300	0.170	0.590	1.014
Autumn	300-330	0.170	0.590	0.983
Autumn	330-360	0.170	0.590	0.355
Average	**All Sectors**	**0.160**	**0.470**	**0.360**

Table G-2. Sector-by-Sector, Season-by-Season Surface Characteristics for BWG at Average Moisture Conditions

Season	Wind Dir.	Albedo	Bowen Ratio	Surf. Roughness
Winter	0-30	0.170	0.790	0.109
Winter	30-60	0.170	0.790	0.023
Winter	60-90	0.170	0.790	0.018
Winter	90-120	0.170	0.790	0.023
Winter	120-150	0.170	0.790	0.031
Winter	150-180	0.170	0.790	0.035
Winter	180-210	0.170	0.790	0.024
Winter	210-240	0.170	0.790	0.038
Winter	240-270	0.170	0.790	0.055
Winter	270-300	0.170	0.790	0.101
Winter	300-330	0.170	0.790	0.187
Winter	330-360	0.170	0.790	0.264
Spring	0-30	0.150	0.470	0.109
Spring	30-60	0.150	0.470	0.031
Spring	60-90	0.150	0.470	0.025
Spring	90-120	0.150	0.470	0.029
Spring	120-150	0.150	0.470	0.038
Spring	150-180	0.150	0.470	0.045
Spring	180-210	0.150	0.470	0.032
Spring	210-240	0.150	0.470	0.047
Spring	240-270	0.150	0.470	0.072
Spring	270-300	0.150	0.470	0.101
Spring	300-330	0.150	0.470	0.187
Spring	330-360	0.150	0.470	0.264
Summer	0-30	0.170	0.510	0.109
Summer	30-60	0.170	0.510	0.037
Summer	60-90	0.170	0.510	0.030
Summer	90-120	0.170	0.510	0.034
Summer	120-150	0.170	0.510	0.045
Summer	150-180	0.170	0.510	0.071
Summer	180-210	0.170	0.510	0.052
Summer	210-240	0.170	0.510	0.059
Summer	240-270	0.170	0.510	0.132
Summer	270-300	0.170	0.510	0.101
Summer	300-330	0.170	0.510	0.187
Summer	330-360	0.170	0.510	0.264
Autumn	0-30	0.170	0.790	0.109
Autumn	30-60	0.170	0.790	0.031
Autumn	60-90	0.170	0.790	0.025
Autumn	90-120	0.170	0.790	0.029
Autumn	120-150	0.170	0.790	0.040
Autumn	150-180	0.170	0.790	0.064
Autumn	180-210	0.170	0.790	0.045
Autumn	210-240	0.170	0.790	0.053
Autumn	240-270	0.170	0.790	0.123
Autumn	270-300	0.170	0.790	0.101
Autumn	300-330	0.170	0.790	0.187
Autumn	330-360	0.170	0.790	0.264
Average	**All Sectors**	**0.165**	**0.640**	**0.085**

Table G-3. Sector-by-Sector, Season-by-Season Surface Characteristics Comparison between GRGS and BWG

Season	Wind Dir.	Albedo	Bowen Ratio	Surf. Roughness
Winter	0-30	0.94	0.75	0.40
Winter	30-60	0.94	0.75	2.78
Winter	60-90	0.94	0.75	1.78
Winter	90-120	0.94	0.75	1.13
Winter	120-150	0.94	0.75	1.52
Winter	150-180	0.94	0.75	0.94
Winter	180-210	0.94	0.75	1.63
Winter	210-240	0.94	0.75	13.89
Winter	240-270	0.94	0.75	11.84
Winter	270-300	0.94	0.75	6.80
Winter	300-330	0.94	0.75	2.82
Winter	330-360	0.94	0.75	0.81
Spring	0-30	0.93	0.77	0.51
Spring	30-60	0.93	0.77	2.58
Spring	60-90	0.93	0.77	1.56
Spring	90-120	0.93	0.77	1.17
Spring	120-150	0.93	0.77	1.63
Spring	150-180	0.93	0.77	0.98
Spring	180-210	0.93	0.77	1.59
Spring	210-240	0.93	0.77	17.79
Spring	240-270	0.93	0.77	11.89
Spring	270-300	0.93	0.77	8.62
Spring	300-330	0.93	0.77	4.10
Spring	330-360	0.93	0.77	1.13
Summer	0-30	1.00	0.67	0.70
Summer	30-60	1.00	0.67	2.43
Summer	60-90	1.00	0.67	1.57
Summer	90-120	1.00	0.67	2.71
Summer	120-150	1.00	0.67	3.73
Summer	150-180	1.00	0.67	1.76
Summer	180-210	1.00	0.67	1.83
Summer	210-240	1.00	0.67	19.47
Summer	240-270	1.00	0.67	7.58
Summer	270-300	1.00	0.67	10.04
Summer	300-330	1.00	0.67	5.26
Summer	330-360	1.00	0.67	1.34
Autumn	0-30	1.00	0.75	0.70
Autumn	30-60	1.00	0.75	2.90
Autumn	60-90	1.00	0.75	1.88
Autumn	90-120	1.00	0.75	3.17
Autumn	120-150	1.00	0.75	4.20
Autumn	150-180	1.00	0.75	1.95
Autumn	180-210	1.00	0.75	2.11
Autumn	210-240	1.00	0.75	21.68
Autumn	240-270	1.00	0.75	8.14
Autumn	270-300	1.00	0.75	10.04
Autumn	300-330	1.00	0.75	5.26
Autumn	330-360	1.00	0.75	1.34
Average	**All Sectors**	**0.97**	**0.73**	**4.23**

Table G-4. One Sector Seasonal Average Surface Characteristics Comparison between GRGS and BWG

Season	Albedo	Bowen Ratio	Surf. Roughness
Winter	0.94	0.75	3.19
Spring	0.93	0.77	4.08
Summer	1.00	0.67	4.63
Autumn	1.00	0.75	4.85

APPENDIX H: MODELED GRGS EMISSION SOURCE INVENTORY

Table H-1. Complete List of Modeled Sources for GRGS

Model ID	Description	Source Type
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	Point
CT1OP2	Combined Cycle Combustion Turbine #1 - 75% Load	Point
CT1OP3	Combined Cycle Combustion Turbine #1 - 50% Load	Point
CT1SUSD	Combined Cycle Combustion Turbine #1 - Startup/Shutdown	Point
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	Point
CT2OP2	Combined Cycle Combustion Turbine #2 - 75% Load	Point
CT2OP3	Combined Cycle Combustion Turbine #2 - 50% Load	Point
CT2SUSD	Combined Cycle Combustion Turbine #2 - Startup/Shutdown	Point
EG1	Emergency Generator #1	Point
BOILER	Auxiliary Boiler	Point
FP1	Fire Pump Engine #1	Point
HEATER	Fuel Gas Heater	Point

Table H-2. List of Stack Parameters and Emission Rates for 1-hour CO SIL Analysis (English Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (ft)	Emission Rate (lb/hr)	Stack Height (ft)	Stack Temp.[a] (°F)	Exit Velocity[a] (ft/s)	Diameter (ft)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	440.00	13.78	180.00	201.43	59.81	21.00
CT1OP2	Combined Cycle Combustion Turbine #1 - 75% Load	488954.10	4135366.90	440.00	10.84	180.00	185.22	40.82	21.00
CT1OP3	Combined Cycle Combustion Turbine #1 - 50% Load	488954.10	4135366.90	440.00	8.33	180.00	175.86	36.16	21.00
CT1SUSD	Combined Cycle Combustion Turbine #1 - Startup/Shutdown	488954.10	4135366.90	440.00	991.06	180.00	135.00	36.86	21.00
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	440.00	13.78	180.00	201.43	59.81	21.00
CT2OP2	Combined Cycle Combustion Turbine #2 - 75% Load	488983.10	4135320.60	440.00	10.84	180.00	185.22	40.82	21.00
CT2OP3	Combined Cycle Combustion Turbine #2 - 50% Load	488983.10	4135320.60	440.00	8.33	180.00	175.86	36.16	21.00
CT2SUSD	Combined Cycle Combustion Turbine #2 - Startup/Shutdown	488983.10	4135320.60	440.00	991.06	180.00	135.00	36.86	21.00
EG1	Emergency Generator #1	488899.70	4135368.80	440.00	0.55	11.00	950.00	270.00	0.67
BOILER	Auxiliary Boiler	488866.50	4135344.90	440.00	7.49	42.00	622.00	60.00	3.50
FP1	Fire Pump Engine #1	488835.80	4135426.90	445.00	0.80	10.00	905.00	270.00	0.50
HEATER	Fuel Gas Heater	488890.00	4135183.00	440.00	1.26	10.00	1000.00	63.34	1.33

[a] Each of the sources are modeled at the temperature and exit velocity corresponding to the worst-case emission rate for the given load condition.

Table H-3. List of Stack Parameters and Emission Rates for 8-hour CO SIL Analysis (English Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (ft)	Emission Rate (lb/hr)	Stack Height (ft)	Stack Temp.[a] (°F)	Exit Velocity[a] (ft/s)	Diameter (ft)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	440.00	13.78	180.00	201.43	59.81	21.00
CT1OP2	Combined Cycle Combustion Turbine #1 - 75% Load	488954.10	4135366.90	440.00	10.84	180.00	185.22	40.82	21.00
CT1OP3	Combined Cycle Combustion Turbine #1 - 50% Load	488954.10	4135366.90	440.00	8.33	180.00	175.86	36.16	21.00
CT1SUSD	Combined Cycle Combustion Turbine #1 - Startup/Shutdown	488954.10	4135366.90	440.00	135.80	180.00	135.00	36.86	21.00
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	440.00	13.78	180.00	201.43	59.81	21.00
CT2OP2	Combined Cycle Combustion Turbine #2 - 75% Load	488983.10	4135320.60	440.00	10.84	180.00	185.22	40.82	21.00
CT2OP3	Combined Cycle Combustion Turbine #2 - 50% Load	488983.10	4135320.60	440.00	8.33	180.00	175.86	36.16	21.00
CT2SUSD	Combined Cycle Combustion Turbine #2 - Startup/Shutdown	488983.10	4135320.60	440.00	135.80	180.00	135.00	36.86	21.00
EG1	Emergency Generator #1	488899.70	4135368.80	440.00	0.55	11.00	950.00	270.00	0.67
BOILER	Auxiliary Boiler	488866.50	4135344.90	440.00	7.49	42.00	622.00	60.00	3.50
FP1	Fire Pump Engine #1	488835.80	4135426.90	445.00	0.80	10.00	905.00	270.00	0.50
HEATER	Fuel Gas Heater	488890.00	4135183.00	440.00	1.26	10.00	1000.00	63.34	1.33

[a] Each of the sources are modeled at the temperature and exit velocity corresponding to the worst-case emission rate for the given load condition.

Table H-4. List of Stack Parameters and Emission Rates for 1-hour CO SIL Analysis (Metric Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp.[a] (K)	Exit Velocity[a] (m/s)	Diameter (m)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	134.11	1.74	54.86	367.28	18.23	6.40
CT1OP2	Combined Cycle Combustion Turbine #1 - 75% Load	488954.10	4135366.90	134.11	1.37	54.86	358.27	12.44	6.40
CT1OP3	Combined Cycle Combustion Turbine #1 - 50% Load	488954.10	4135366.90	134.11	1.05	54.86	353.07	11.02	6.40
CT1SUSD	Combined Cycle Combustion Turbine #1 - Startup/Shutdown	488954.10	4135366.90	134.11	124.87	54.86	330.37	11.23	6.40
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	134.11	1.74	54.86	367.28	18.23	6.40
CT2OP2	Combined Cycle Combustion Turbine #2 - 75% Load	488983.10	4135320.60	134.11	1.37	54.86	358.27	12.44	6.40
CT2OP3	Combined Cycle Combustion Turbine #2 - 50% Load	488983.10	4135320.60	134.11	1.05	54.86	353.07	11.02	6.40
CT2SUSD	Combined Cycle Combustion Turbine #2 - Startup/Shutdown	488983.10	4135320.60	134.11	124.87	54.86	330.37	11.23	6.40
EG1	Emergency Generator #1	488899.70	4135368.80	134.11	0.07	3.35	783.15	82.30	0.20
BOILER	Auxiliary Boiler	488866.50	4135344.90	134.11	0.94	12.80	600.93	18.29	1.07
FP1	Fire Pump Engine #1	488835.80	4135426.90	135.64	0.10	3.05	758.15	82.30	0.15
HEATER	Fuel Gas Heater	488890.00	4135183.00	134.11	0.16	3.05	810.93	19.30	0.41

[a] Each of the sources are modeled at the temperature and exit velocity corresponding to the worst-case emission rate for the given load condition.

Table H-5. List of Stack Parameters and Emission Rates for 8-hour CO SIL Analysis (Metric Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (m)	Emission Rate (g/s)	Stack Height (m)	Stack Temp.[a] (K)	Exit Velocity[a] (m/s)	Diameter (m)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	134.11	1.74	54.86	367.28	18.23	6.40
CT1OP2	Combined Cycle Combustion Turbine #1 - 75% Load	488954.10	4135366.90	134.11	1.37	54.86	358.27	12.44	6.40
CT1OP3	Combined Cycle Combustion Turbine #1 - 50% Load	488954.10	4135366.90	134.11	1.05	54.86	353.07	11.02	6.40
CT1SUSD	Combined Cycle Combustion Turbine #1 - Startup/Shutdown	488954.10	4135366.90	134.11	17.11	54.86	330.37	11.23	6.40
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	134.11	1.74	54.86	367.28	18.23	6.40
CT2OP2	Combined Cycle Combustion Turbine #2 - 75% Load	488983.10	4135320.60	134.11	1.37	54.86	358.27	12.44	6.40
CT2OP3	Combined Cycle Combustion Turbine #2 - 50% Load	488983.10	4135320.60	134.11	1.05	54.86	353.07	11.02	6.40
CT2SUSD	Combined Cycle Combustion Turbine #2 - Startup/Shutdown	488983.10	4135320.60	134.11	17.11	54.86	330.37	11.23	6.40
EG1	Emergency Generator #1	488899.70	4135368.80	134.11	0.07	3.35	783.15	82.296	0.203
BOILER	Auxiliary Boiler	488866.50	4135344.90	134.11	0.94	12.80	600.93	18.29	1.07
FP1	Fire Pump Engine #1	488835.80	4135426.90	135.64	0.10	3.05	758.15	82.296	0.152
HEATER	Fuel Gas Heater	488890.00	4135183.00	134.11	0.16	3.05	810.93	19.30	0.41

[a] Each of the sources are modeled at the temperature and exit velocity corresponding to the worst-case emission rate for the given load condition.

Table H-6. Summary of Modeled Source Groups in the Significance Analysis

Scenario	CO 1-hr/8-hr S1	CO 1-hr/8-hr S2	CO 1-hr/8-hr S3	CO 1-hr/8-hr S4	CO 1-hr/8-hr S5	CO 1-hr/8-hr S6	CO 1-hr/8-hr S7	CO 1-hr/8-hr S8
Sources	CT1OP1 CT2OP1 EG1 BOILER FP1 HEATER	CT1OP2 CT2OP2 EG1 BOILER FP1 HEATER	CT1OP3 CT2OP3 EG1 BOILER FP1 HEATER	CT1SUSD CT2SUSD EG1 BOILER FP1 HEATER	CT1OP1 CT2OP2 EG1 BOILER FP1 HEATER	CT1OP1 CT2OP3 EG1 BOILER FP1 HEATER	CT1OP1 CT2SUSD EG1 BOILER FP1 HEATER	CT1OP2 CT2OP1 EG1 BOILER FP1 HEATER

Scenario	CO 1-hr/8-hr S9	CO 1-hr/8-hr S10	CO 1-hr/8-hr S11	CO 1-hr/8-hr S12	CO 1-hr/8-hr S13	CO 1-hr/8-hr S14	CO 1-hr/8-hr S15	CO 1-hr/8-hr S16
Sources	CT1OP2 CT2OP3 EG1 BOILER FP1 HEATER	CT1OP2 CT2SUSD EG1 BOILER FP1 HEATER	CT1OP3 CT2OP1 EG1 BOILER FP1 HEATER	CT1OP3 CT2OP2 EG1 BOILER FP1 HEATER	CT1OP3 CT2SUSD EG1 BOILER FP1 HEATER	CT1SUSD CT2OP1 EG1 BOILER FP1 HEATER	CT1SUSD CT2OP2 EG1 BOILER FP1 HEATER	CT1SUSD CT2OP3 EG1 BOILER FP1 HEATER

APPENDIX I: AIR TOXICS MODELING ANALYSIS SUPPORTING DOCUMENTATION

Table I-1. Maximum Potential HAP/Toxic Emissions Summary - Non-Cancer Cbronic (English Units)

Pollutant	CAS No.	Potential Emission Rate TURBINE[a] ER_{Aj} (lb/hr)	BOILER[b] ER_{Aj} (lb/hr)	HEATER[c] ER_{Aj} (lb/hr)	Resident Air Screening Level - Non-Cancer[d] RSL_{NCj} (ug/m³)	RSL-Normalized Emission Rate TURBINE ER_{Aj}/RSL_{NCj} (lb/hr)/(ug/m³)	BOILER ER_{Aj}/RSL_{NCj} (lb/hr)/(ug/m³)	HEATER ER_{Aj}/RSL_{NCj} (lb/hr)/(ug/m³)
1,3-Butadiene	106-99-0	1.66E-04			2.10	7.90E-05		
Acetaldehyde	75-07-0	1.18E-01			9.40	1.26E-02		
Acrolein	107-02-8	1.53E-02			0.021	7.30E-01		
Ammonia	7664-41-7	1.95E+01			100	1.95E-01		
Arsenic	7440-38-2		2.00E-05	3.01E-06	0.016		1.25E-03	1.88E-04
Barium	7440-39-3		4.41E-04	6.62E-05	0.52		8.48E-04	1.27E-04
Benzene	71-43-2	3.58E-02	2.10E-04	3.16E-05	31.0	1.15E-03	6.79E-06	1.02E-06
Beryllium	7440-41-7		1.20E-06	1.80E-07	0.021		5.72E-05	8.59E-06
Cobalt	7440-48-4		8.41E-06	1.26E-06	0.0063		1.34E-03	2.01E-04
Ethylbenzene	100-41-4	6.26E-02			1,000	6.26E-05		
Formaldehyde	50-00-0	7.26E-01	7.51E-03	1.13E-03	10.0	7.26E-02	7.51E-04	1.13E-04
Hexane	110-54-3		1.80E-01	2.71E-02	730.0		2.47E-04	3.71E-05
Lead	7439-92-1		5.01E-05	7.52E-06	0.15		3.34E-04	5.01E-05
Mercury	7439-97-6		2.60E-05	3.91E-06	0.31		8.40E-05	1.26E-05
Naphthalene	91-20-3	1.74E-03	6.11E-05	9.17E-06	3.1	5.60E-04	1.97E-05	2.96E-06
Nickel	7440-02-0		2.10E-04	3.16E-05	0.094		2.24E-03	3.36E-04
Pentane	109-66-0		2.60E-01	3.91E-02	1,000		2.60E-04	3.91E-05
Propylene Oxide	75-56-9	7.84E-02			31.0	2.53E-03		
Selenium	7782-49-2		2.40E-06	3.61E-07	21.0		1.14E-07	1.72E-08
Toluene	108-88-3	1.86E-01	3.41E-04	5.11E-05	5,200	3.58E-05	6.55E-08	9.83E-09
Vanadium	7440-62-2		2.30E-04	3.46E-05	0.10		2.30E-03	3.46E-04
Xylene (Total)	1330-20-7	1.78E-01			100	1.78E-03		
Total RSL-Normalized Emission Rate $ER_{NCi} = \sum ER_{Aj} / RSL_{NCj}$						**1.02**	**9.74E-03**	**1.46E-03**

[a] Hourly potential turbine TAP emission rates based on worst-case controlled annual potential emission rate of the three (3) turbine options in ton per year (tpy) divided by 8,760 hr/yr.

[b] Hourly potential boiler TAP emission rates based on maximum heat input capacity (MMBtu/hr) multiplied by AP-42, Chapter 1.4 reference emission factors for natural gas combustion.

[c] Hourly potential fuel-gas heater TAP emission rates based on maximum heat input capacity (MMBtu/hr, HHV) multiplied by AP-42, Chapter 1.4 reference emissions factors for natural gas combustion.

[d] U.S. EPA Region 3 Mid-Atlantic Risk Assessment, Risk-Based Screening Table, November 2013
(available at http://www.epa.gov/reg3hwmd/risk/human/rh-concentration_table/Generic_Tables/index.htm)

Table I-2. Maximum Potential HAP/Toxic Emissions Summary - Cancer Chronic (English Units)

Pollutant	CAS No.	Potential Emission Rate TURBINE[a] ER_{Aj} (lb/hr)	 BOILER[b] ER_{Aj} (lb/hr)	 HEATER[c] ER_{Aj} (lb/hr)	Resident Air Screening Level - Cancer[d] RSL_{Cj} (ug/m^3)	RSL-Normalized Emission Rate TURBINE ER_{Aj}/RSL_{Cj} (lb/hr)/(ug/m^3)	 BOILER ER_{Aj}/RSL_{Cj} (lb/hr)/(ug/m^3)	 HEATER ER_{Aj}/RSL_{Cj} (lb/hr)/(ug/m^3)
1,3-Butadiene	106-99-0	1.66E-04			0.081	2.05E-03		
3-Methylchloranthrene	56-49-5		1.80E-07	2.71E-08	0.00015		1.20E-03	1.80E-04
7,12-Dimethylbenz(a)anthracene	57-97-6		1.60E-06	2.41E-07	0.000014		1.14E-01	1.72E-02
Acetaldehyde	75-07-0	1.18E-01			1.10	1.07E-01		
Arsenic	7440-38-2		2.00E-05	3.01E-06	0.00057		3.51E-02	5.28E-03
Benzene	71-43-2	3.58E-02	2.10E-04	3.16E-05	0.31	1.15E-01	6.79E-04	1.02E-04
Benzo(a)anthracene	56-55-3		1.80E-07	2.71E-08	0.0087		2.07E-05	3.11E-06
Benzo(a)pyrene	50-32-8		1.20E-07	1.80E-08	0.00087		1.38E-04	2.07E-05
Benzo(b)fluoranthene	205-99-2		1.80E-07	2.71E-08	0.0087		2.07E-05	3.11E-06
Benzo(k)fluoranthene	207-08-9		1.80E-07	2.71E-08	0.0087		2.07E-05	3.11E-06
Beryllium	7440-41-7		1.20E-06	1.80E-07	0.001		1.20E-03	1.80E-04
Chrysene	218-01-9		1.80E-07	2.71E-08	0.087		2.07E-06	3.11E-07
Cobalt	7440-48-4		8.41E-06	1.26E-06	0.00027		3.12E-02	4.68E-03
Dibenzo(a,h)anthracene	53-70-3		1.20E-07	1.80E-08	0.0008		1.50E-04	2.26E-05
Ethylbenzene	100-41-4	6.26E-02			0.97	6.45E-02		
Formaldehyde	50-00-0	7.26E-01	7.51E-03	1.13E-03	0.19	3.82E+00	3.95E-02	5.94E-03
Indeno(1,2,3-cd)pyrene	193-39-5		1.80E-07	2.71E-08	0.0087		2.07E-05	3.11E-06
Naphthalene	91-20-3	1.74E-03	6.11E-05	9.17E-06	0.072	2.41E-02	8.49E-04	1.27E-04
Nickel	7440-02-0		2.10E-04	3.16E-05	0.0094		2.24E-02	3.36E-03
Propylene Oxide	75-56-9	7.84E-02			0.66	1.19E-01		
Total RSL-Normalized Emission Rate $ER_{Ci} = \sum ER_{Aj} / RSL_{Cj}$						**4.25**	**0.25**	**0.037**

[a] Hourly potential turbine TAP emission rates based on worst-case controlled annual potential emission rate of the three (3) turbine options in ton per year (tpy) divided by 8,760 hr/yr.

[b] Hourly potential boiler TAP emission rates based on maximum heat input capacity (MMBtu/hr) multiplied by AP-42, Chapter 1.4 reference emission factors for natural gas combustion.

[c] Hourly potential fuel-gas heater TAP emission rates based on maximum heat input capacity (MMBtu/hr, HHV) multiplied by AP-42, Chapter 1.4 reference emissions factors for natural gas combustion.

[d] U.S. EPA Region 3 Mid-Atlantic Risk Assessment, Risk-Based Screening Table, November 2013
(available at http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/Generic_Tables/index.htm)

Table I-3. Maximum Potential HAP/Toxic Emissions Summary - Non-Cancer Chronic (Metric Units)

Pollutant	CAS No.	Potential Emission Rate TURBINE[a] ER_{Aj} (g/s)	Potential Emission Rate BOILER[b] ER_{Aj} (g/s)	Potential Emission Rate HEATER[c] ER_{Aj} (g/s)	Resident Air Screening Level - Non-Cancer[d] RSL_{NCj} (ug/m^3)	RSL-Normalized Emission Rate TURBINE ER_{Aj}/RSL_{NCj} (g/s)/(ug/m^3)	RSL-Normalized Emission Rate BOILER ER_{Aj}/RSL_{NCj} (g/s)/(ug/m^3)	RSL-Normalized Emission Rate HEATER ER_{Aj}/RSL_{NCj} (g/s)/(ug/m^3)
1,3-Butadiene	106-99-0	2.09E-05			2.10	9.95E-06		
Acetaldehyde	75-07-0	1.49E-02			9.40	1.58E-03		
Acrolein	107-02-8	1.93E-03			0.021	9.20E-02		
Ammonia	7664-41-7	2.46E+00			100	2.46E-02		
Arsenic	7440-38-2		2.52E-06	3.79E-07	0.016		1.58E-04	2.37E-05
Barium	7440-39-3		5.55E-05	8.34E-06	0.52		1.07E-04	1.60E-05
Benzene	71-43-2	4.51E-03	2.65E-05	3.98E-06	31.0	1.45E-04	8.55E-07	1.28E-07
Beryllium	7440-41-7		1.51E-07	2.27E-08	0.021		7.21E-06	1.08E-06
Cobalt	7440-48-4		1.06E-06	1.59E-07	0.0063		1.68E-04	2.53E-05
Ethylbenzene	100-41-4	7.89E-03			1,000	7.89E-06		
Formaldehyde	50-00-0	9.14E-02	9.46E-04	1.42E-04	10.0	9.14E-03	9.46E-05	1.42E-05
Hexane	110-54-3		2.27E-02	3.41E-03	730.0		3.11E-05	4.67E-06
Lead	7439-92-1		6.31E-06	9.47E-07	0.15		4.21E-05	6.32E-06
Mercury	7439-97-6		3.28E-06	4.93E-07	0.31		1.06E-05	1.59E-06
Naphthalene	91-20-3	2.19E-04	7.70E-06	1.16E-06	3.1	7.05E-05	2.48E-06	3.73E-07
Nickel	7440-02-0		2.65E-05	3.98E-06	0.094		2.82E-04	4.23E-05
Pentane	109-66-0		3.28E-02	4.93E-03	1,000		3.28E-05	4.93E-06
Propylene Oxide	75-56-9	9.88E-03			31.0	3.19E-04		
Selenium	7782-49-2		3.03E-07	4.55E-08	21.0		1.44E-08	2.17E-09
Toluene	108-88-3	2.35E-02	4.29E-05	6.44E-06	5,200	4.51E-06	8.25E-09	1.24E-09
Vanadium	7440-62-2		2.90E-05	4.36E-06	0.10		2.90E-04	4.36E-05
Xylene (Total)	1330-20-7	2.25E-02			100	2.25E-04		
Total RSL-Normalized Emission Rate $ER_{NCi} = \sum ER_{Aj} / RSL_{NCj}$						**0.13**	**1.23E-03**	**1.84E-04**

[a] Hourly potential turbine TAP emission rates based on worst-case controlled annual potential emission rate of the three (3) turbine options in ton per year (tpy) divided by 8,760 hr/yr.

[b] Hourly potential boiler TAP emission rates based on maximum heat input capacity (MMBtu/hr) multiplied by AP-42, Chapter 1.4 reference emission factors for natural gas combustion.

[c] Hourly potential fuel-gas heater TAP emission rates based on maximum heat input capacity (MMBtu/hr, HHV) multiplied by AP-42, Chapter 1.4 reference emissions factors for natural gas combustion.

[d] U.S. EPA Region 3 Mid-Atlantic Risk Assessment, Risk-Based Screening Table, November 2013
(available at http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/Generic_Tables/index.htm)

Table I-4. Maximum Potential HAP/Toxic Emissions Summary - Cancer Chronic (Metric Units)

Pollutant	CAS No.	Potential Emission Rate TURBINE[a] ER_{Aj} (g/s)	BOILER[b] ER_{Aj} (g/s)	HEATER[c] ER_{Aj} (g/s)	Resident Air Screening Level - Cancer[d] RSL_{Cj} (ug/m^3)	RSL-Normalized Emission Rate TURBINE ER_{Aj}/RSL_{Cj} (g/s)/(ug/m^3)	BOILER ER_{Aj}/RSL_{Cj} (g/s)/(ug/m^3)	HEATER ER_{Aj}/RSL_{Cj} (g/s)/(ug/m^3)
1,3-Butadiene	106-99-0	2.09E-05			0.081	2.58E-04		
3-Methylchloranthrene	56-49-5		2.27E-08	3.41E-09	0.00015		1.51E-04	2.27E-05
7,12-Dimethylbenz(a)anthracene	57-97-6		2.02E-07	3.03E-08	0.000014		1.44E-02	2.17E-03
Acetaldehyde	75-07-0	1.49E-02			1.10	1.35E-02		
Arsenic	7440-38-2		2.52E-06	3.79E-07	0.00057		4.43E-03	6.65E-04
Benzene	71-43-2	4.51E-03	2.65E-05	3.98E-06	0.31	1.45E-02	8.55E-05	1.28E-05
Benzo(a)anthracene	56-55-3		2.27E-08	3.41E-09	0.0087		2.61E-06	3.92E-07
Benzo(a)pyrene	50-32-8		1.51E-08	2.27E-09	0.00087		1.74E-05	2.61E-06
Benzo(b)fluoranthene	205-99-2		2.27E-08	3.41E-09	0.0087		2.61E-06	3.92E-07
Benzo(k)fluoranthene	207-08-9		2.27E-08	3.41E-09	0.0087		2.61E-06	3.92E-07
Beryllium	7440-41-7		1.51E-07	2.27E-08	0.001		1.51E-04	2.27E-05
Chrysene	218-01-9		2.27E-08	3.41E-09	0.087		2.61E-07	3.92E-08
Cobalt	7440-48-4		1.06E-06	1.59E-07	0.00027		3.93E-03	5.90E-04
Dibenzo(a,h)anthracene	53-70-3		1.51E-08	2.27E-09	0.0008		1.89E-05	2.84E-06
Ethylbenzene	100-41-4	7.89E-03			0.97	8.13E-03		
Formaldehyde	50-00-0	9.14E-02	9.46E-04	1.42E-04	0.19	4.81E-01	4.98E-03	7.48E-04
Indeno(1,2,3-cd)pyrene	193-39-5		2.27E-08	3.41E-09	0.0087		2.61E-06	3.92E-07
Naphthalene	91-20-3	2.19E-04	7.70E-06	1.16E-06	0.072	3.04E-03	1.07E-04	1.61E-05
Nickel	7440-02-0		2.65E-05	3.98E-06	0.0094		2.82E-03	4.23E-04
Propylene Oxide	75-56-9	9.88E-03			0.66	1.50E-02		
Total RSL-Normalized Emission Rate $ER_{Ci} = \sum ER_{Aj} / RSL_{Cj}$						**0.54**	**0.03**	**0.005**

[a] Hourly potential turbine TAP emission rates based on worst-case controlled annual potential emission rate of the three (3) turbine options in ton per year (tpy) divided by 8,760 hr/yr.

[b] Hourly potential boiler TAP emission rates based on maximum heat input capacity (MMBtu/hr) multiplied by AP-42, Chapter 1.4 reference emission factors for natural gas combustion.

[c] Hourly potential fuel-gas heater TAP emission rates based on maximum heat input capacity (MMBtu/hr, HHV) multiplied by AP-42, Chapter 1.4 reference emissions factors for natural gas combustion.

[d] U.S. EPA Region 3 Mid-Atlantic Risk Assessment, Risk-Based Screening Table, November 2013
(available at http://www.epa.gov/reg3hwmd/risk/human/rb-concentration_table/Generic_Tables/index.htm)

Table I-5. Air Toxics Modeling - Non-Cancer Chronic (English Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (ft)	Normalized Emission Rate (lb/hr)/(ug/m3)	Stack Height (ft)	Stack Temperature (°F)	Exit Velocity (ft/s)	Diameter (ft)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	440.00	1.016774E+00	180.00	201.43	59.81	21.00
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	440.00	1.016774E+00	180.00	201.43	59.81	21.00
BOILER	Auxiliary Boiler	488866.50	4135344.90	440.00	9.736678E-03	42.00	622.00	60.00	3.50
HEATER	Fuel Gas Heater	488890.00	4135183.00	440.00	1.461964E-03	10.00	1000.00	63.34	1.33

Table I-6. Air Toxics Modeling - Cancer Chronic (English Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (ft)	Normalized Emission Rate (lb/hr)/(ug/m3)	Stack Height (ft)	Stack Temperature (°F)	Exit Velocity (ft/s)	Diameter (ft)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	440.00	4.251446E+00	180.00	201.43	59.81	21.00
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	440.00	4.251446E+00	180.00	201.43	59.81	21.00
BOILER	Auxiliary Boiler	488866.50	4135344.90	440.00	2.469916E-01	42.00	622.00	60.00	3.50
HEATER	Fuel Gas Heater	488890.00	4135183.00	440.00	3.708583E-02	10.00	1000.00	63.34	1.33

Table I-7. Air Toxics Modeling - Non-Cancer Chronic (Metric Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (m)	Normalized Emission Rate (g/s)/(ug/m3)	Stack Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Diameter (m)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	134.11	1.281107E-01	54.86	367.28	18.23	6.40
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	134.11	1.281107E-01	54.86	367.28	18.23	6.40
BOILER	Auxiliary Boiler	488866.50	4135344.90	134.11	1.226794E-03	12.80	600.93	18.29	1.07
HEATER	Fuel Gas Heater	488890.00	4135183.00	134.11	1.842034E-04	3.05	810.93	19.30	0.41

Table I-8. Air Toxics Modeling - Cancer Chronic (Metric Units)

Model ID	Description	UTM East (m)	UTM North (m)	Elevation (m)	Normalized Emission Rate (g/s)/(ug/m3)	Stack Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Diameter (m)
CT1OP1	Combined Cycle Combustion Turbine #1 - 100% Load	488954.10	4135366.90	134.11	5.356704E-01	54.86	367.28	18.23	6.40
CT2OP1	Combined Cycle Combustion Turbine #2 - 100% Load	488983.10	4135320.60	134.11	5.356704E-01	54.86	367.28	18.23	6.40
BOILER	Auxiliary Boiler	488866.50	4135344.90	134.11	3.112026E-02	12.80	600.93	18.29	1.07
HEATER	Fuel Gas Heater	488890.00	4135183.00	134.11	4.672712E-03	3.05	810.93	19.30	0.41

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 82

Witness: Gregory J. Meiman

Q-82. Reference Mr. Meiman's testimony, page 4, lines 13-16. What changes in the currently proposed CPCN would need to be made in order to take full advantage of the Kentucky tax incentives, and what are the possible implications of those changes.

A-82. No changes are needed in the proposed CPCN. The limiting factor to taking full advantage of the Kentucky tax incentives is the nature of the tax incentives that Kentucky offers and the Companies' overall Kentucky tax position. Kentucky offers tax incentives which may include (i) tax relief up to 100% of the Kentucky state income tax arising from income earned by the project, (ii) sales and use tax refunds up to 100% of tax paid on materials, machinery and equipment, used to construct the project, or (iii) a wage assessment of up to 4% of gross wages on associated employees whose jobs were created as a result of the project.

The Companies stated that the practical opportunities for use of incentives may be limited or unavailable. In this regard, the Kentucky state income tax arising from the project is anticipated to be limited. Also, the Companies believe there will be little sales and use tax paid on this project as a result of other available exemptions. Finally, it is anticipated at this time that there will be a limited amount of wages from employees whose jobs were created with this solar project. The Companies will monitor all three of these incentive options and will seek to take advantage of them if possible.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 83

Witness: John N. Voyles, Jr.

Q-83. Will the temperature of the water currently discharged from the Green River site be more than 5 degrees different than the water to be discharged if the facility proposed is constructed? If so, what will the proposed temperature of the water from the facility be?

A-83. The proposed Green River NGCC will use a cooling tower to limit discharge flow back to the Green River. The existing Green River units 3 and 4 are using once through cooling discharging about 98 million gallons per day on a summer day. Replacing the existing Green River units 3 and 4 with Green River NGCC will result in a 95% reduction in flow at a discharge temperature within 5^0F of the existing units.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 84

Witness: John N. Voyles, Jr.

Q-84. Reference the testimony of Mr. Voyles at page 5, lines 1-3, whereat the witness states: "At this time, the Companies do not expect circumstances that would require new high voltage electric transmission lines for which transmission CPCNs from the Commission would be required, **but this issue is being studied."** (Emphasis added.)

a. When do the companies anticipate concluding this study? And

b. If the study finds that upgrades are needed, can the companies currently provide an estimate on the projected costs?

A-84.

a. The study requested of the Companies' Independent Transmission Organization (ITO), as required under the Companies' OATT, is currently expected to start March 31, 2014 and be completed approximately in July 2014.

b. Based on preliminary studies conducted by the Companies' Transmission engineers, upgrades have been identified with preliminary cost estimates. None of the currently identified upgrades have met the definitions specified for transmission CPCN processes. Once the ITO study is complete and final upgrades are identified, the Companies will begin more detailed engineering of the required work and can provide an estimate of any additional upgrades beyond those already identified and include them in the final projected cost estimates.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 85

Witness: John N. Voyles, Jr.

Q-85. Reference the testimony of Mr. Voyles at page 5, lines 12-13 whereat the witness tates that: "approximately 120 acres will need to be purchased for siting setback requirements."

a. From whom will this land be purchased?

b. Have the Companies secured contractual agreement(s) to purchase the land?, and

c. If so, has that cost been included in the application?

A-85. See the response to PSC 1-33.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 86

Witness: John N. Voyles, Jr.

Q-86. Reference the testimony of Mr. Voyles at page 5, lines 21-23, whereat the witness states: "Construction of the Green River NGCC (which will be a designated resource for the Companies) at the current Green River site reduces the need to rely more heavily on the transmission grid." Explain this statement in detail.

A-86. See the response to Question No. 33.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 87

Witness: John N. Voyles, Jr.

Q-87. Reference the testimony of Mr. Voyles at page 10, lines 9 -10, whereat the witness states: "The Companies anticipate an approximately 11-mile route mostly along existing electric transmission rights-of-way as depicted in Exhibit 4 to the Joint Application."

a. Is part of the land along the possible route for the gas transmission line owned by non-Companies' entities?

b. If so, who owns the land?

c. Have the Companies secured contractual agreement(s) to purchase the land?, and

d. If so, has that cost been included in the application?

A-87.

a. Yes, the parcels of land along the possible gas transmission route are owned by a number of individual property owners.

b. Muhlenberg County PVA records were used to produce the attached table of property ownership. Final route selection and pipeline design may result in changes to the list.

c. No.

d. The estimated cost of the right-of-way acquisition has been included in the application.

GREEN RIVER 5 GAS TRANSMISSION PROPOSED ROUTES (1 & 2) PVA LANDOWNER LIST on 11 x 17

	Common Parcels on routes 1&2	Easement New or Existing	161 KV Elect Trans Str#	69KV Elect Tran Str#	Map Page #	County	PVA Parcel ID#	Last Name	First Name	Spouse	Other Name	Name Corp/Legal	Street #	Street Name	City	State	Zip	Mailing Street Number	Mailing Street Name	Mailing City	Mailing State	Mailing Zip	PVA PARCEL ACREAGE
1	common	Existing	2-3			Muhlenburg	138-00-00-003.000	Dunlap	Ray C.									190	Rumsey Lane	Greenville	KY	42345	123
2	common	Existing	4-5			Muhlenburg	120-00-00-008.002	Brewer	Jackie D.	Mary K.			12485	US Hwy 431 N	Central City	KY	42330						3.87
3	common	Existing	6			Muhlenburg	120-00-00-008.004	Brewer	Richard H.				12291	US Hwy 431 N	Central City	KY	42330						283
4	common	Existing	7			Muhlenburg	120-00-00-008.003	Richey	Don	Joy			2400	State Rt 81	Central City	KY	42330						98
5	common	Existing	8-9			Muhlenburg	120-00-00-009.000	Richey	Don	Joy			2400	US Hwy Rt 81	Central City	KY	42330	2400	State Rt 81	Central City	KY	42330	84
6	common	Existing	10-11			Muhlenburg	121-00-00-002.000	Richey	Don	Joy	Leon Sylvester Harrison		2400	Railroad LN	Central City	KY	42330	2400	State Rt 81	Central City	KY	42330	783
7	common	Existing	12-14			Muhlenburg	121-00-00-001.000	Alward	Bill	Molly			555	Main Street	Central City	KY	42330		PO Box 135	South Carrollton	KY	42374	0
8	common	Existing	15-17			Muhlenburg	103-00-00-010.000	Harris	Sherman					State Rt 2584 O	Central City	KY	42330	95	Hayes Lane	Central City	KY	423330	101.7
9	common	Existing	18			Muhlenburg	103-00-00-024-010	Rosso	W.A.					Wolcut Lan	Central City	KY	42330	455	Charlie Brown Rd	Central City	KY	423330	146.26
10	common	Existing	18-22			Muhlenburg	103-00-00-024.011	Rosso	W.A.					Wolcut Lan	Central City	KY	42330	455	Charlie Brown Rd	Central City	KY	423331	60
11	common	Existing	23-24			Muhlenburg	103-00-00-021.000	Nelson	Dwight	Audra			1384	Billy Drake Rd	Central City	KY	42330						55 62
12	common	Existing	25-26			Muhlenburg	103-00-00-006.000	Clouse	William L.	Vickie L.	Michael D & Audrey F Clouse			Billy Drake Rd	Central City	KY	42330	205	State Rt 593	Calhoun	KY	42327	55 62
13	common	Existing	27			Muhlenburg	103-00-00-006.020	Clouse	William L.	Vickie L.	Michael D & Audrey F Clouse			Billy Drake Rd	Central City	KY	42330	205	State Rt 593	Calhoun	KY	42327	0
14	common	Existing	27			Muhlenburg	103-00-00-006.021	Clouse	William L.	Vickie L.	Michael D & Audrey F Clouse			Billy Drake Rd	Central City	KY	42330	205	State Rt 593	Calhoun	KY	42327	0
15	common	Existing	28			Muhlenburg	103-00-00-006.001	Lambert	James A					Billy Drake Rd	Central City	KY	42330	8144	Hwy 764 S	Whitesville	KY	42378	14
16	common	Existing	29-30			Muhlenburg	085-00-00-036.000	Richey	Odessa				400	Muddy Fork Lane	Central City	KY	42330	587	Baker Rd	Bremen	KY	42325	37 06
17	common	Existing	30			Muhlenburg	103-00-00-001.000	Vinson	Barry				500	Billy Drake Rd	Central City	KY	42330	1200	State Rt 81	Sacremento	KY	42372	41 87
18	common	Existing	30			Muhlenburg	085-00-00-036.003	Haire	John	Doris			210	Muddy Fork Lane	Central City	KY	42330						3.205
19	common	Existing	31-32			Muhlenburg	085-00-00-031.000	Craig	William				3029	State Rt 81	Central City	KY	42330						72
20	common	Existing	33			Muhlenburg	085-00-00-028.005	Gossett	Mary Belle Hagan				3140	State Rt 81	Central City	KY	42330						21
21	common	Existing	33			Muhlenburg	085-00-00-030.000	Gossett	Robert H	Mary			3140	State Rt 81	Central City	KY	423330						0
22	common	Existing	34			Muhlenburg	085-00-00-028.004	Smith	Ramona Myrtle						Central City	KY	42330	128	Pennington Ln	Corbin	KY	40701	21
23	common	Existing	34-35			Muhlenburg	085-00-00-028.003	Hagan	Joseph D.						Central City	KY	42330	341	Spring Valley Dr.	Cottontown	TN	37048	21

	Common Parcels on routes 1&2	Easement New or Existing	161 KV Elect Trans Str#	69KV Elect Tran Str#	Map Page #	County	PVA Parcel ID#	Last Name	First Name	Spouse	Other Name	Name Corp/Legal	Street #	Street Name	City	State	Zip	Mailing Street Number	Mailing Street Name	Mailing City	Mailing State	Mailing Zip	PVA PARCEL ACREAGE
24	common	Existing	36-37			Muhlenburg	085-00-00-028.002	Harris	Norma Esther		C/O Mary Gossett. 3140 St Rd 81 Central City, KY 42330				Central City	KY	42330	3140	St Rt 81	Central City	KY	42330	21
25	common	Existing	69kv only			Muhlenburg	085-00-00-028.001	Hagan	Miles Silas		C/o Mary Gossett				Central City	KY	42330	3141	St Rt 81	Central City	KY	42331	21
26	common	Existing	38			Muhlenburg	085-00-00-021.001	Bullock	Payton						Central City	KY	42330	2380	KY Hwy 550	Sacremento	KY	42372	66
27	common	Existing	39-42			Muhlenburg	085-00-00-018.000	Jones	J.C.						Central City	KY	42330	374	Cherry Grove Ln	Greenville	KY	42345	89
28	common	Existing	43			Muhlenburg	068-00-00-037.000	Bullock	Payton						Central City	KY	42330	2380	KY Hwy 550	Sacremento	KY	42372	34
29	common	Existing	44			Muhlenburg	068-00-00-034.000	Jones	J.C.					State Rt 81	Central City	KY	42330	374	Cherry Grove Ln	Greenville	KY	42345	3
30	common	Existing	44			Muhlenburg	068-00-00-033.000	**CEMETERY**				**CEMETERY**											0
31	common	Existing	44			Muhlenburg	068-00-00-031.000					CAL Maine Partnership LTD	11500	N. State Rt 81	Central City	KY	42330		PO Box 2960	Jackson	MS	39207	76
32	common	Existing	45			Muhlenburg	068-00-00-032.000	Shavers	Chapel					State Rt 81	Central City	KY	42330						0
33	common	Existing	45-47			Muhlenburg	068-00-00-021.000	Jones	J.C.		Otis Jones		11233	State Rt 81	Central City	KY	42330	374	Cherry Grove Ln	Greenville	KY	42345	88
34	common	Existing	48			Muhlenburg	068-00-00-039.000	Rhoades	Joe H.	Jean			10725	State Rt 81	Central City	KY	42330	10725	St Rt 81	Bremen	KY	42325	33
35	common	Existing	48			Muhlenburg	068-00-00-024.000	Rhoades	Robert B.				315	Bennett Ln	Central City	KY	42330						127.47
36	common	Existing	48			Muhlenburg	068-00-00-019.000	Hendricks	Timothy J.	Jacqueline Ann						KY	42330	5550	State Rt 175 N	Sacremento	KY	42372	41
37	common	Existing	49-50			Muhlenburg	068-00-00-018.000	Hendricks	Timothy J.	Jacqueline Ann						KY	42330	5550	State Rt 175 N	Sacremento	KY	42372	43
38	common	Existing	51			Muhlenburg	068-00-00-023.000	Hendricks	Timothy J.	Jacqueline Ann						KY	42330	5550	State Rt 175 N	Sacremento	KY	42372	62
39	common	Existing	51-52			Muhlenburg	068-00-00-017.000	Hendricks	Timothy J.	Jacqueline Ann						KY	42330	5550	State Rt 175 N	Sacremento	KY	42372	50
40	common	Existing	52			Muhlenburg	068-00-00-016.000	Jones	J.C.							KY	42330	374	Cherry Grove Ln	Greenville	KY	42345	34
41	common	Existing	53-55			Muhlenburg	051-00-00-038.000	Jones	J.C.	Juanita						KY	42330	374	Cherry Grove Ln	Greenville	KY	42345	63
42	common	Existing	56-57			Muhlenburg	051-00-00-034.000	Jarvis	John Gary	Susan				St Rt 2551		KY	42330		PO Box 68	Bremen	KY	42325	105
43	common	Existing	58			Muhlenburg	051-00-00-036.000					BB&D Timber Co % Jean Brown		St Rt 2551 O		KY	42330	3567	Willie Simmons Rd	Falls of Rough	KY	40119	185
44	common	Existing	58-59			Muhlenburg	051-00-00-035.000					BB&D Timber Co % Jean Brown		St Rt 2551		KY	42330	3567	Willie Simmons Rd	Falls of Rough	KY	40120	0
45	common	Existing	59-60			Muhlenburg	051-00-00-020.000	Vincent	Wayne	Candy			2162	St Rt 2551	Bremen	KY	42325						14
46	common	Existing	60			Muhlenburg	051-00-00-019.000	Hobgood	Malcolm Arthur				2218	St Rt 2551	Bremen	KY	42325						15
47	common	Existing	61			Muhlenburg	051-00-00-017.000	Yates	Francis J.	Kimberly J.			2274	St Rt 2551	Bremen	KY	42325						56

	Common Parcels on routes 1&2	Easement New or Existing	161 KV Elect Trans Str#	69KV Elect Tran Str#	Map Page #	County	PVA Parcel ID#	Last Name	First Name	Spouse	Other Name	Name Corp/Legal	Street #	Street Name	City	State	Zip	Mailing Street Number	Mailing Street Name	Mailing City	Mailing State	Mailing Zip	PVA PARCEL ACREAGE
48	common	Existing	62-63			Muhlenburg	052-00-00-002.000	Jones	Doris				2636	St Rt 2551	Bremen	KY	42325						87
49	common	Existing	64-65			Muhlenburg	052-00-00-001.000	Grogan	Darren Charles	Lisa Gwyn			1100	Miller Rd	Bremen	KY	42325						163.6
50	common	Existing	66-67			Muhlenburg	037-00-00-037.000	Jarvis	Thomas J.	Maureen			2918	State Rt 2551	Bremen	KY	42325						28
51	common	Existing	68			Muhlenburg	037-00-00-037.001	Stogner	Scotty				1491	Miller Rd	Bremen	KY	42325						18 906
52	common	Existing	69-75			Muhlenburg	037-00-00-008.000					Ken American Resources, Inc	175	St Rt N	Bremen	KY	42325	153	Highway 7 S	Powhatan Point	OH	43942	1071
53	common	Existing	76-77			Muhlenburg	037-00-00-001.000	Zoellick	Brian M.				2383	St Rt 175 N	Bremen	KY	42325	60	Toombs Ln	Bremen	KY	42325	54.41
54	common	Existing	76			Muhlenburg	037-00-00-002.001	Hobgood	Charles	Anna Ruth			2514	St Rt 175 N	Bremen	KY	42325						0.91
55	common	Existing	78			Muhlenburg	037-00-00-048.000	Caudill	Ray	Margie			3171	Phillipstown Rd	Bremen	KY	42325						38.748
56	common	Existing	79-81			Muhlenburg	023-00-00-001.001	Caudill	Dwayne	Tammy Lynn			1378	Phillipstown Rd	Bremen	KY	42325						57.76
57	common	Existing	69kv only			Muhlenburg	023-00-00-005.000	Caudill	Archie G.	Reva A.				Phillipstown Rd	Bremen	KY	42325	1376	Yellow Springs Fairfield Rd	Fairborn	OH	45324	4.5
58	common	Existing	69kv only			Muhlenburg	023-00-00-002-000	Miller	Fred C.				6034	Phillipstown Rd	Bremen	KY	42325	6034	St Rt 70 W	Bremen	KY	42325	48
59	common	Existing	81-85			Muhlenburg	023-00-00-001.000					Western Land Co LLC C/o Armstrong Coal Company		St Rt 70 W	Bremen	KY	42325	407	Brown Rd	Madisonville	KY	42431	3108

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 88

Witness: David S. Sinclair

Q-88. Reference the testimony of Mr. Voyles at page 10, lines 13-16, whereat the witness states: "Additionally, the Companies have had discussions with Texas Gas and ANR Pipeline Company about providing the interstate gas transportation necessary to supply the Green River NGCC and the meter station that will be necessary at the delivery point. Those discussions are ongoing."

a. When do the Companies contemplate reaching an agreement?

b. What are the costs upon which the Companies anticipate agreeing? (Specify each type of cost and the amount.)

c. Have the companies provided this information in the record? If so, where?

A-88.

a. The Companies expect to execute a contract for firm gas transportation in the first quarter of 2015.

b. The Companies assumed $22.4 million in 2018 and this amount escalates at 2 percent annually.

c. See Appendix A on page 49 of Exhibit DSS-1. Firm gas transportation costs in Appendix A are in 2015 dollars.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 89

Witness: David S. Sinclair

Q-89. Reference the testimony of Mr. Voyles at page 11, lines 8-10, whereat the witness states: "The Green River NGCC is expected to generate approximately 4,900 GWh per year beginning in 2018, resulting in an annual total fixed and non-fuel operating cost of approximately $14.5 million." Provide a detailed breakdown of each and every fixed and non-fuel operating cost by type and cost.

A-89. See the response to PSC 1-34.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 90

Witness: John N. Voyles, Jr.

Q-90. Reference the testimony of Mr. Voyles at page 12, lines 4-9, whereat the witness states: "The estimated electric transmission cost of all projects which may be required in 2018 or earlier to support the Green River NGCC is approximately $100 million. It is important to note that this cost estimate continues to be refined as new information becomes available and further engineering is performed. Of course, to the extent Commission approval is required for any electric transmission work, timely application will be made."

a. On what do the Companies base their estimate of $100 million?

b. When do the Companies anticipate concluding its cost estimate?

A-90.

a. Based on preliminary studies conducted by the Companies' Transmission engineers, anticipated upgrades were identified, along with preliminary cost estimates, which would be required by 2018 to support the Green River NGCC. (See the response to Question No. 179 for additional details.) However, finalization of those upgrade projects and associated cost estimates cannot be made until the completion of the Generator Interconnection Study to be conducted by the ITO. (See the response to Question No. 84(a).)

b. See the response to Question No. 84 (b).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Question No. 91

Witness: John N. Voyles, Jr.

Q-91. Reference the testimony of Mr. Voyles at page 13, lines 16-22, whereat the witness states: "The transmission and distribution infrastructure already in place at Brown means that the Companies do not anticipate any significant modifications or upgrades will be necessary to transmit power produced by the 10 MW solar facility. As with the Green River NGCC, the Companies will file as appropriate, an interconnect request with TranServ to identify what modifications, if any, will be required. However, at this time, the Companies expect that the existing transmission and distribution infrastructure at Brown will be adequate to handle the additional power."

a. When will the Companies know whether any significant modifications or upgrades will be necessary?

b. Could there be additional costs not included in the application with the modifications or upgrades?

c. When will the Companies know what modifications to the interconnect will be necessary?

d. Could there be additional costs not included in the application with the interconnect?

A-91.

a. Based on a preliminary review conducted by the Companies' Transmission engineers, the Companies do not believe significant modifications or upgrades will be necessary. The Companies will know if significant modifications or upgrades will be necessary upon completion of the Generator Interconnection System Impact Study per the Companies' OATT to be performed by the ITO.

b. There could be additional costs not included in the application. However, based on preliminary studies conducted by the Companies' Transmission engineers, these costs are not expected to be material.

c. The Companies will know if significant modifications to the interconnect will be necessary upon completion of the Generator Interconnection System Impact Study to be performed by the ITO.

d. There could be additional costs not included in the application. However, based on preliminary studies conducted by the Companies' Transmission engineers, these costs are not expected to be material.

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KENTUCKY UTILITIES COMPANY

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Question No. 92

Witness: John N. Voyles, Jr.

Q-92. Reference the testimony of Mr. Voyles at page 14, lines 4-11, whereat the witness states: "With that deadline in place, the Companies have contracted with HDR to develop a conceptual design. An OE for the project will be selected in early 2014 to develop detailed specifications for the site preparation requirements, solar panel systems and associated electrical inverter connections. We expect to take those specifications to the EPC marketplace thereafter. The total project cost is estimated to be approximately $36 million pending final site sizing and preparation, consisting of approximately $26 million for solar generating system equipment, $3 million for site preparation work, and $7 million for owner's costs."

A-92. Nothing in Question No. 92, as written, asks a question to which the Companies can respond.

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Question No. 93

Witness: John N. Voyles, Jr.

Q-93. Provide a detailed overview of HDR, including its history with the solar industry (with all projects listed in which it has participated whether financially profitable or not).

a. When will an actual design be developed rather than one that is merely conceptual in nature?

b. Upon what do the Companies "estimate" the total project costs?

c. When do the Companies project the total costs will be known?

d. Provide a detailed breakdown by type and cost for the solar generating system equipment.

e. Provide a detailed breakdown by type of work and cost for the $3 million for site preparation work.

f. Describe in detail the costs associated with the $7 million in owner's costs.

A-93. HDR is an engineering firm, not a solar developer, and as such does not own any projects so they do not participate financially in solar projects.

a. Detailed design is anticipated to occur in 2015.

b. See the response to PSC 1-31.

c. The projected costs of the Brown Solar Facility are based on a conceptual estimate at this time. Firm project costs will be developed after the project has been issued for bid to the market in 2015.

d. See the response to PSC 1-31.

e. The site will be graded to a gentle southern slope with limited and consistent east to west grade changes. Access roads will also be constructed.

f. See the response to PSC 1-31.

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Question No. 94

Witness: David S. Sinclair

Q-94. Reference the testimony of Mr. Voyles at page 14, lines 18-21, whereat the witness states: "In the Resource Assessment, conceptual fixed and variable operating and maintenance costs for the Brown Solar Facility are assumed to be $12.50/kW-year and $0.80/MWh, respectively. Based on these numbers, the annual total operating cost will be approximately $140,000."

a. When will the Companies have actual costs versus conceptual costs?

b. Provide a detailed breakdown for each and every fixed and variable cost.

A-94.

a. Actual cost will not be known until the Brown Solar Facility is operational.

b. See the response to PSC 1-35b.

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Question No. 95

Witness: Gary H. Revlett

Q-95. Reference the testimony of Mr. Revlett at page 4, lines 10-16, whereat the witness states: "The newest rule that affected the Companies' analysis is the Proposed Greenhouse Gas Rule, which will impose the first carbon-dioxide emissions restrictions on electric generating units in the United States. It applies only to new, not existing, electric generating units. As I describe further below, the proposed restrictions will effectively eliminate utilities' ability to build economical coal units in the foreseeable future, making NGCC the fossil-fuel technology of choice in situations where other non-coal-fired alternatives are not more economical." Stated in other terms, is the witness testifying that, going forward, new coal-fired generation is simply uneconomical and will not be built under the current regulations?

A-95. The process of carbon capture and storage (CCS) for new coal generation is considered uneconomical on both a capital and an operational basis. The capital concerns are primarily associated with the cost of equipment necessary for removal of CO_2 and the cost to construct pipeline and deep-well sequestration of the carbon dioxide. The operational costs are primarily associated with the additional energy use required to operate the CO_2 collection equipment. Together, these costs would increase the price of electricity by as much as 80% according to the Department of Energy (DOE)/National Energy Technology Laboratory (NETL), "Carbon Dioxide Capture and Storage RD&D Roadmap" (Dec. 2010).

Reliability and feasibility issues with CCS additionally play a large role in determining that the proposed Greenhouse Gas Rule for new coal fired generation will prohibit the construction of new coal-fired electric generating units. The technology has not been demonstrated in the United States on full scale coal-fired, electric generating facilities and concerns remain with liability issues associated with injecting millions of tons of CO_2 annually underground make this process impracticable.

Therefore, as a result, of the combination of economics, lack of demonstrated feasibility and long-term reliability risk associated with the required CCS in the proposed regulations, the construction of any new coal based generation is highly unlikely.

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Question No. 96

Witness: Daniel K. Arbough / Edwin R. Staton

Q-96. With reference the testimony of Mr. Staton, pages 3 and 4, and Table 11, page 17 of the application. Please provide the following:

a. The workpapers (in hard copy and Microsoft Excel) used to develop the proposed capital structure percentages of 45.7% long-term debt and 54.3% equity;

b. The proposed percentage of short-term and long-term debt included in the debt portion of the capital structure;

c. What is the timeline of the proposed of debt and equity financings that will be required to finance the project;

d. How the Companies determined that a return on equity of 10.5% was appropriate for the proposed project.

A-96.

a. See attached.

b. See subpart a. There is no short-term debt in the actual capitalization at year end 2011, and therefore none was used in calculating the proposed capital structure.

c. The Companies do not project finance individual projects. Long-term debt will be issued when the short-term debt balances begin to approach $250 million at an individual Company which is the minimum amount for a long-term debt to become index eligible and achieve the most attractive interest rates. LG&E and KU Energy LLC, the parent company of the Companies, would make equity contributions to the Companies on a quarterly basis if needed to maintain the capital structure near the Companies' target capital structure.

d. The cost of the proposed projects will impact all of the jurisdictions that the Companies' serve. The average allowed return on equity across all of these jurisdictions was approximately 10.5% at year-end 2011. The return on equity is used to compute the revenue requirement discount rate. A slightly higher or lower return on equity would not have a material impact on the ranking of the alternatives.

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Question No. 97

Witness: Daniel K. Arbough

Q-97. With reference the testimony of Mr. Staton, pages 3 and 4, and Table 11, page 17 of the application, how it was determined that the proposed capital structure is required to " … allow the Companies to maintain their strong investment-grade credit ratings."

A-97. The Companies strive to maintain a capital structure that aligns with the guidelines established by major rating agencies to maintain their strong investment-grade credit ratings. A strong investment-grade credit rating translates to a credit rating in the "A" category. Most recently, Moody's Investor Services published an updated Rating Methodology for Regulated Electric and Gas Utilities dated December 23, 2013 which is attached. In the table presented on page 24 of the article, Moody's notes that an A rated utility should maintain a Debt/Capitalization ratio in the range of 35%-45%. The proposed capital structure is actually slightly more aggressive than the prescribed range from Moody's. However, it is consistent with the Companies historical capital structure and no negative ratings impact is expected with the proposed capital structure.

DECEMBER 23, 2013

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

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Summary

This rating methodology explains Moody's approach to assessing credit risk for regulated electric and gas utilities globally and is intended to provide general guidance that helps companies, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for companies in the regulated electric and gas utility industry. This document does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology replaces[1] the Rating Methodology for Regulated Electric and Gas Utilities published in August 2009. While reflecting many of the same core principles as the 2009 methodology, this updated document provides a more transparent presentation of the rating considerations that are usually most important for companies in this sector and incorporates refinements in our analysis that better reflect credit fundamentals of the industry. No rating changes will result from publication of this rating methodology.

This report includes a detailed rating grid and illustrative examples that compare the mapping of rated public companies against the factors in the grid. The grid is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the illustrative mapping examples in this document use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

1 This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains fonr key factors that are important in our assessment for ratings in the regulated electric and gas ntility sector, and a notching factor for structural subordination at holding companies:

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

Some of these factors also encompass a number of sub-factors. Since an issuer's scoring on a particular grid factor or sub-factor often will not match its overall rating, in Appendix C we include a discussion of some of the grid "outliers" – companies whose grid-indicated rating for a specific sub-factor differs significantly from the actual rating – in order to provide additional insights.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid nsed for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that would map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), a list of the companies included in our illustrative sample universe of issuers with their ratings, grid-indicated ratings and country of domicile (Appendix B), tables that illustrate the application of the grid to the sample universe of issuers, with explanatory comments on some of the more significant differences between the grid-implied rating for each sub-factor and our actual rating (Appendix C)[2], our approach to ratings within a utility family (Appendix D), a description of the various types of companies rated under this methodology (Appendix E), key industry issues over the intermediate term (Appendix F), regional and other considerations (Appendix G), and treatment of power purchase agreements (Appendix H).

[2] In general, the rating (or other indicator of credit strength) utilized for comparison to the grid-implied rating is the senior unsecured rating for investment-grade issuers, the Corporate Family Rating (CFR) for speculative-grade issuers and the Baseline Credit Assessment (BCA) for Government Related Issuers (GRIs). Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. Related documents that provide additional insight in this area are the rating methodologies "Loss Given Default for Speculative Grade Non-Financial Companies in the US, Canada and EMEA", published June 2009, and "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers", published February 2007.

What's Changed

While incorporating many of the core principles of the 2009 version, this methodology updates how the four key rating factors are defined, and how certain sub-factors are weighted in the grid.

More specifically, this methodology introduces four equally weighted sub-factors into the two rating factors that are related to regulation –the Regulatory Framework and the Ability to Recover Costs and Earn Returns – in order to provide more granularity and transparency on the overall regulatory environment, which is the most important consideration for this sector.

The weighting of the grid indicators for diversification are unchanged, but the proposed descriptive criteria have been refined to place greater emphasis on the economic and regulatory diversity of each utility's service area rather than the diversity of operations, because we think this emphasis better distinguishes credit risk. We have refined the definitions of the Generation and Fuel Diversity sub-factor to better incorporate the full range of challenges that can affect a particular fuel type.

While the overall weighting of the Financial Strength factor is unchanged, the weighting for two sub-factors that seek to measure debt in relation to cash flow has increased. The 15% weight for CFO Pre-WC/Debt reflects our view that this is the single most predictive financial measure, followed in importance by CFO Pre-WC - Dividends/Debt with a 10% grid weighting. The additional weighting of these ratios is balanced by the elimination of a separate liquidity sub-factor that had a 10% weighting in the prior grid.

Liquidity assessment remains a key focus of our analysis. However, we consider it as a qualitative assessment outside the grid because its credit importance varies greatly over time and by issuer and accordingly is not well represented by a fixed grid weight. See "Other Rating Considerations" for insights on liquidity analysis in this sector.

Lower financial metric thresholds have been introduced for certain utilities viewed as having lower business risk, for instance many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers). The low end of the scale in the methodology grid has been extended from B to Caa to better capture our views of more challenging regulatory environments and weaker performance.

We have introduced minor changes to financial metric thresholds at the lower end of the scale, primarily to incorporate this extension of the grid.

We have incorporated scorecard notching for structural subordination at holding companies. Ratings already incorporated structural subordination, but including an adjustment in the scorecard will result in a closer alignment of grid-indicated outcomes and ratings for holding companies.

Treatment of first mortgage bonds (primarily in the US), which was the subject of a Request for Comment in 2009 and adopted subsequent to the 2009 methodology, is summarized in Appendix G.

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found here.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[3] electric and gas utilities that are not Networks[4]. Regulated Electric and Gas Utilities are companies whose predominant[5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas ntilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix E, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the snb-sovereign level is often more accessible for participation by interveners, including disaffected cnstomers and the politicians who want their votes. Onr views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.

3 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

4 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

5 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

Other Related Methodologies

» Regulated Electric and Gas Networks

» Unregulated Utilities and Power Companies

» Natural Gas Pipelines

» US Public Power Electric Utilities with Generation Ownership Exposure

» US Electric Generation & Transmission Cooperatives

» US Municipal Joint Action Agencies

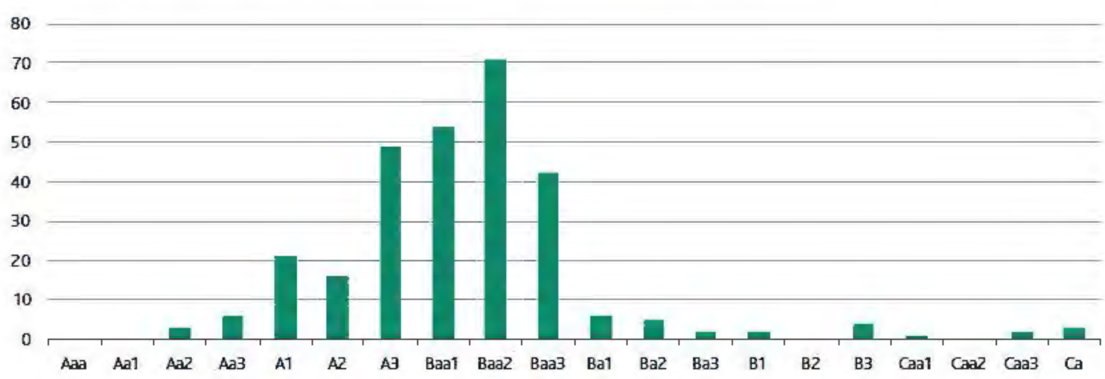
» Government Related Issuers: Methodology Update

» Global Regulated Water Utilities

The rated universe includes approximately 315 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. These companies account for about US$730 billion of total outstanding long-term debt instruments.

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments. Additional information about the ratings and default performance of the sector can be found in our publication "Infrastructure Default and Recovery Rates, 1983-2012H1". As shown on the following table, the ratings spectrum for issuers in the sector (both holding companies and operating companies) ranges from Aaa to Ca:

EXHIBIT 1
Regulated Electric and Gas Utilities' Senior Unsecured Ratings Distribution



Source: Moody's Investors Service, ratings as of December 2013

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in seven sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
		Holding Company Structural Subordination	0 to -3

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

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in this document to illustrate the application of the rating grid. All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.

For definitions of Moody's most common ratio terms please see Moody's Basic Definitions for Credit Statistics, User's Guide (June 2011, document #78480). For a description of Moody's standard adjustments, please see Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations December 2010 (128137). These documents can be found at www.moodys.com under the Research and Ratings directory.

In most cases, the illustrative examples in this document use historic financial data from a recent three year period. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the snb-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

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

In Appendix C, we provide a table showing how each company in the sample set of issuers maps to grid-indicated ratings for each rating sub-factor and factor. We highlight companies whose grid-indicated performance on a specific sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss the general reasons for such positive and negative outliers for a particular sub-factor.

5. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 wonld have a Ba2 grid-indicated rating. We nsed a similar procedure to derive the grid indicated ratings shown in the illustrative examples.

7. Appendices

The Appendices provide illnstrative examples of grid-indicated ratings based on historical financial information and also provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

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

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[6] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or jndicial decisions have created a body of precedent that will help determine future rate-making. Since the focns of our scoring is on each issuer, we consider

6 In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit-supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.
Ba	**B**	**Caa**	
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.	

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second-guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision-making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa	
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.	

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

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and bnsiness decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assnrance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness. Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time. For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the nnmber of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or indnstry. In onr assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub-factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to economically shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score higher in this sub-factor. Issners that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will score lower.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issner that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sonrces. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sonrces, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resonrces plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	"Challenged Sources" are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	"Threatened Sources" are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non-utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income. Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities. However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

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

The cash flow interest coverage ratio is an indicator for a ntility's ability to cover the cost of its borrowed capital. The numerator in the ratio calcnlation is the snm of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi-permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with Moody's standard adjustments[7], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[8]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation ntilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

7 In certain circumstances, analysts may also apply specific adjustments.

8 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos preseut their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the gronp's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-streamed by the OpCos[9]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non-financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[10] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issnance at the OpCo level is another reason that structural subordination is usnally a more serious concern in the utility sector than for investment grade issners in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structnral subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural snbordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

- Regulatory or other barriers to cash movement from OpCos to HoldCo
- Specific ring-fencing provisions
- Strict financial covenants at the OpCo level
- Higher leverage at the OpCo level
- Higher leverage at the HoldCo level[11]
- Significant dividend limitations or potential limitations at an important OpCo
- HoldCo exposnre to snbsidiaries with high business risk or volatile cash flows

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[9] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[10] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[11] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix D has additional insights on ratings within a utility family.

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

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

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liqnidity position.

Other Rating Considerations

Moody's considers other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider onr assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending dnring the 2007-2009 recession. Dividends represent a quasi-permanent ontlay, since utilities will typically only rarely cnt their dividend. Liqnidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity has generally not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides Moody's with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structnre and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the sнccess of ntilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[12]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid-indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

[12] See also the cross-sector methodology How Sovereign Credit Quality May Affect Other Ratings, February 2012.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accnracy of audited financial statements to assign and monitor ratings in this sector. Snch accuracy is only possible when companies have sufficient internal controls, inclnding centralized operations, the proper tone at the top and consistency in acconnting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 45 representative utilities shown in the illustrative mapping examples, the grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

» 33% or 15 companies map to their assigned rating

» 49% or 22 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating

» 16% or 7 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

» 2% or 1 company has a grid-indicated rating that is within three alpha-numeric notches of its assigned rating

Grid Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch
American Electric Power Company, Inc.	Appalachian Power Company
China Longyuan Power Group Corporation Ltd.	Arizona Public Service Company
Chubu Electric Power Company, Incorporated	China Resources Gas Group Limited
Entergy Corporation	Duke Energy Corporation
FortisBC Holdings Inc.	Florida Power & Light Company
Great Plains Energy Incorporated	Georgia Power Company
Hokuriku Electric Power Company	Hawaiian Electric Industries, Inc.
Madison Gas & Electric	Idaho Power Company
MidAmerican Energy Company	Kansai Electric Power Company, Incorporated
Mississippi Power Company	Korea Electric Power Corporation
Newfoundland Power Inc.	MidAmerican Energy Holdings Co.
Oklahoma Gas and Electric Company	Niagara Mohawk Power Corporation
Osaka Gas Co., Ltd.	Northern States Power Minnesota
Saudi Electricity	Okinawa Electric Power Company, Incorporated
Wisconsin Public Service Corporation	PacifiCorp
	Pennsylvania Electric Company
	PNG Companies
	Public Service Company of New Mexico
	SCANA
	Southwestern Public Service Company
	UGI Utilities, Inc.
	Virginia Electric Power Company

Map to Within Two Notches	Map to Within Three or More Notches
Ameren Illinois Company	Western Mass Electric Co.
Consumers Energy Company	
Distribuidora de Electricidad La Paz S.A.	
Empresa Electrica de Guatemala, S.A. (EEGSA)	
Gail (India) Ltd	
Gas Natural Ban, S.A.	
Ohio Power Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.
Ba	**B**	**Caa**	
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.	

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Regulated Electric and Gas Utilities – Assigned Ratings and Grid-Indicated Ratings for a Selected Cross-Section of Issuers

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift*[13]	Grid Indicated Rating	Country
1	Ameren Illinois Company	RUR-Up	Baa2	-	A3	USA
2	American Electric Power Company, Inc.	RUR-Up	Baa2	-	Baa2	USA
3	Appalachian Power Company	RUR-Up	Baa2	-	Baa1	USA
4	Arizona Public Service Company	RUR-Up	Baa1	-	A3	USA
5	China Longyuan Power Group Corporation	Stable	Baa3	*Ba1*	Ba1	China
6	China Resources Gas Group Ltd.	Stable	Baa1	*Baa2*	Baa1	China
7	Chubu Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa2	Japan
8	Consumers Energy Company	RUR-Up	(P)Baa1	-	A2	USA
9	Distribuidora de Electricidad La Paz S.A.	Stable	Ba3	-	Ba1	Bolivia
10	Duke Energy Corporation	RUR-Up	Baa1	-	Baa2	USA
11	Empresa Electrica de Guatemala, S.A.	Positive	Ba2	-	Baa3	Guatemala
12	Entergy Corporation	Stable	Baa3	-	Baa3	USA
13	Florida Power & Light Company	RUR-Up	A2	-	A1	USA
14	FortisBC Holdings Inc.	Negative	Baa2	-	Baa2	Canada
15	Gail (India) Ltd	Stable	Baa2	*Baa2*	A3	India
16	Gas Natural BAN, S.A.	Negative	B3	-	B1	Argentina
17	Georgia Power Company	Stable	A3	-	A2	USA
18	Great Plains Energy Incorporated	RUR-Up	Baa3	-	Baa3	USA
19	Hawaiian Electric Industries, Inc.	RUR-Up	Baa2	-	Baa1	USA
20	Hokuriku Electric Power Company	Negative	A3	*Baa2*	Baa2	Japan
21	Idaho Power Company	RUR-Up	Baa1	-	A3	USA
22	Kansai Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa3	Japan
23	Korea Electric Power Corporation	Stable	A1	*Baa2*	Baa3	Korea
24	Madison Gas & Electric	RUR-Up	A1	-	A1	USA
25	MidAmerican Energy Company	RUR-Up	A2	-	A2	USA
26	MidAmerican Energy Holdings Co.	RUR-Up	Baa1	-	A3	USA
27	Mississippi Power Company	Stable	Baa1	-	Baa1	USA
28	Niagara Mohawk Power Corporation	RUR-Up	A3	-	A2	USA
29	Newfoundland Power Inc.	Stable	Baa1	-	Baa1	Canada
30	Northern States Power Minnesota	RUR-Up	A3	-	A2	USA
31	Ohio Power Company	Stable	Baa1	-	A2	USA
32	Okinawa Electric Power Company, Inc.	Stable	Aa3	*A2*	A3	Japan
33	Oklahoma Gas & Electric Company	RUR-Up	A2	-	A2	USA
34	Osaka Gas Co., Ltd.	Stable	Aa3	*A1*	A1	Japan

[13] BCA means a Baseline Credit Assessment for a government related issuer. Please see Government Related Issuers: Methodology Update, July 2010. In addition, certain companies in Japan receive a ratings uplift due to country-specific considerations. Please see "Support system for large corporate entities in Japan can provide ratings uplift, with limits" in Appendix G.

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift*[13]	Grid Indicated Rating	Country
35	PacifiCorp	RUR-Up	Baa1	-	A3	USA
36	Pennsylvania Electric Company	Stable	Baa2	-	Baa1	USA
37	PNG Companies LLC	RUR-Up	Baa3	-	Baa2	USA
38	Public Service Company of New Mexico	RUR-Up	Baa3	-	Baa2	USA
39	Saudi Electricity Company	Stable	A1	*Baa1*	Baa1	Saudi Arabia
40	SCANA Corporation	Stable	Baa3	-	Baa2	USA
41	Southwestern Public Service Company	RUR-Up	Baa2	-	Baa1	USA
42	UGI Utilities, Inc.	RUR-Up	A3	-	A2	USA
43	Virginia Electric and Power Company	RUR-Up	A3	-	A2	USA
44	Western Massachusetts Electric Company	RUR-Up	Baa2	-	A2	USA
45	Wisconsin Public Service Corporation	RUR-Up	A2	-	A2	USA

Appendix C: Regulated Electric and Gas Utility Grid Outcomes and Outlier Discussion

In the table below positive or negative "outliers" for a given sub-factor are defined as issuers whose grid sub-factor score is at least two broad rating categories higher or lower than a company's rating (e.g. a B-rated company whose rating on a specific sub-factor is in the Baa-rating category is flagged as a positive outlier for that sub-factor). Green is nsed to denote a positive outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories higher than Moody's rating. Red is used to denote a negative outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories lower than Moody's rating.

Grid-Indicated Ratings

					Factor 1a	Factor 1b		Factor 2a	Factor 2b		Factor 3a	Factor 3b		Factor 4a	Factor 4b	Factor 4c	Factor 4d	
		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	12.50 %	12.50 %	Indicated Factor 2 Rating	12.50 %	12.50 %	Indicated Factor 3 Rating	5.00 %	5.00 %	Indicated Factor 4 Rating	7.50 %	15.00 %	10.00 %	7.50 %	Hold-Co Notching for Structural Subor-dination
1	Ameren Illinois Company	Baa2	A3	Baa	A	Baa	Baa	Aa	Ba	Baa	Baa	-	A	Baa	A	Baa	Aa	n/a
2	American Electric Power Company, Inc.	Baa2	Baa2	A	A	A	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	-1
3	Appalachian Power Company	Baa2	Baa1	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
4	Arizona Public Service Company	Baa1	A3	A	A	A	Baa	A	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
5	China Longyuan Power Group Corporation Ltd.	Baa3 / *Ba1*	Ba1	Ba	Ba	Baa	A	Baa	A	Baa	Baa	A	Ba	Ba	Ba	Baa	B	-1
6	China Resources Gas Group Limited	Baa1 / *Baa2*	Baa1	Ba	Ba	Baa	Ba	Ba	Baa	Baa	Baa	-	A	Aaa	A	A	A	n/a
7	Chubu Electric Power Company, Incorporated	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	Ba	Aa	Ba	Ba	B	n/a
8	Consumers Energy Company	Baa1	A2	A	A	Aa	A	Aa	A	Ba	Baa	Ba	A	A	A	A	Baa	n/a
9	Distribuidora de Electricidad La Paz S.A.	Ba3	Ba1	B	B	Ba	B	B	Ba	B	B	-	A	Baa	A	A	A	n/a
10	Duke Energy Corp.	Baa1	Baa2	A	A	Aa	Baa	A	Baa	A	A	A	Baa	A	Baa	Baa	A	-2
11	Empresa Electrica de Guatemala, S.A. (EEGSA)	Ba2	Baa3	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba	-	Baa	A	Aa	B	A	n/a
12	Entergy Corp	Baa3	Baa3	Baa	A	Baa	Baa	Baa	Baa	A	A	Baa	A	A	A	A	Baa	-2
13	Florida Power & Light Company	A2	A1	A	A	Aa	A	Aa	Baa	A	A	A	Aa	Aaa	Aa	Aa	Aa	n/a
14	FortisBC Holdings Inc.	Baa2	Baa2	A	A	A	A	A	A	A	A	-	Ba	Ba	Ba	Ba	Ba	0
15	Gail (India) Ltd	Baa2 / *Baa2*	A3	Ba	Ba	Ba	Baa	Baa	Baa	Ba	Ba	-	Aa	Aaa	Aaa	Aaa	Aa	n/a
16	Gas Natural Ban, S.A.	B3	B1	Caa	Caa	Caa	Caa	Caa	Caa	B	B	-	A	Ba	A	Baa	Aaa	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
17	Georgia Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	Baa	A	n/a
18	Great Plains Energy Incorporated	Baa3	Baa3	A	A	A	Ba	Baa	Ba	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
19	Hawaiian Electric Industries, Inc.	Baa2	Baa1	A	A	A	A	Aa	A	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	-1
20	Hokuriku Electric Power Company	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Ba	Baa	Ba	Ba	Aa	Ba	Ba	B	n/a
21	Idaho Power Company	Baa1	A3	A	A	A	A	Aa	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	A	n/a
22	Kansai Electric Power Company, Incorporated	A3 / *Baa2*	Baa3	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	B	Ba	B	Ba	Caa	n/a
23	Korea Electric Power Corporation	A1 / *Baa2*	Baa3	Baa	Baa	Baa	Ba	Ba	Ba	A	A	A	Ba	Ba	Ba	Ba	Baa	n/a
24	Madison Gas & Electric	A1	A1	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	Aa	Aa	Aa	Aa	A	n/a
25	MidAmerican Energy Company	A2	A2	A	A	Aa	Ba	Ba	Baa	Baa	Baa	A	A	Aa	A	Aa	A	n/a
26	MidAmerican Energy Holdings Co.	Baa1	A3	A	A	A	Baa	Baa	Baa	A	A	Baa	Baa	Baa	Baa	A	Baa	0
27	Mississippi Power Company	Baa1	Baa1	A	A	A	A	Aa	Baa	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	n/a
28	Niagara Mohawk Power Corporation	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	-	A	Aa	A	A	Aa	n/a
29	Newfoundland Power Inc.	Baa1	Baa1	A	A	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
30	Northern States Power Minnesota	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
31	Ohio Power Company	Baa1	A2	A	A	A	Baa	Baa	A	Ba	Baa	B	A	A	Aa	A	A	n/a
32	Okinawa Electric Power Company, Incorporated	Aa3 / A2	A3	Aa	Aa	Aa	A	A	A	Ba	Ba	Ba	Baa	Aaa	Ba	Baa	B	n/a
33	Oklahoma Gas and Electric Company	A2	A2	A	A	Aa	Baa	Baa	A	Baa	Baa	Baa	A	A	A	A	A	n/a
34	Osaka Gas Co., Ltd.	Aa3 / *A1*	A1	Aa	Aa	Aa	A	A	A	A	A	-	A	Aaa	A	A	A	n/a
35	PacifiCorp	Baa1	A3	A	A	A	Baa	Aa	Ba	Baa	A	Baa	A	A	A	Baa	A	n/a
36	Pennsylvania Electric Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Baa	Baa	-	Baa	Baa	Baa	Ba	A	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
37	PNG Companies	Baa3	Baa2	A	A	A	Ba	Baa	Ba	Baa	Baa	-	Ba	Ba	Ba	Ba	Baa	n/a
38	Public Service Company of New Mexico	Baa3	Baa2	Baa	A	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	A	Baa	A	Baa	n/a
39	Saudi Electricity	A1 / *Baa1*	Baa1	Baa	Baa	A	Ba	Baa	Ba	A	Baa	Aaa	A	Aaa	A	A	Baa	n/a
40	SCANA	Baa3	Baa2	Aa	Aa	Aa	Baa	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
41	Southwestern Public Service Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa	A	n/a
42	UGI Utilities, Inc.	A3	A2	A	A	A	A	A	A	Baa	Baa	-	A	A	A	A	A	n/a
43	Virginia Electric Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
44	Western Mass Electric Co.	Baa2	A2	A	A	Aa	A	A	A	Ba	Ba	-	A	Aa	A	A	A	n/a
45	Wisconsin Public Service Corporation	A2	A2	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	A	A	n/a

Outliers in Legislative and Judicial Underpinnings of the Regulatory Framework

For Chubu Electric Power Company, Hokuriku Electric Power Company, Kansai Electric Power Company, and Okinawa Electric Power Company, our ratings consider the credit-supportive underpinnings in the Electric Utility Industries Law that have been balanced against higher leverage and lower returns than global peers.

For SCANA Corporation, the South Carolina Base Load Review Act provides strong credit support for companies engaging in nuclear new-build, which also affects the scoring for consistency and predictability of regulation. However, SCANA's rating also considers the size and complexity of the nuclear construction project, which is out of scale to the size of the company, as well as structural subordination.

Outliers in Consistency and Predictability of Regulation

Consumers Energy Company has benefitted from increasingly predictable regulatory decisions in Michigan, as well as improved timeliness due to forward test years and the ability to implement interim rates. However, the snbstantial debt at its parent, CMS Energy Corporation (Baa3, RUR-up), has weighed on the ratings.

Duke Energy Corporation has received generally consistent and predictable rate treatment at it subsidiary operating companies, but parent debt has impacted financial metrics

The shift in business mix at Western Massachusetts Electric Company will place a greater percentage of its rate base under the jurisdiction of the FERC, generally viewed as having greater consistency and predictability, which is somewhat tempered by its financial metrics.

Outliers in Timeliness of Recovery of Operating and Capital Costs

Ameren Illinois Company has a formula rate plan that has a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Hawaiian Electric Industries, Inc.'s timeliness has improved considerably due to the introduction in rate-making of a de-coupling mechanism, forward test year and an investment tracker at its utility subsidiary.

For Mississippi Power Company, a fully forward test year and the ability to recover some construction-work-in-progress in rates lead to strong scoring for timeliness. Ratings also consider risks associated with construction of a power plant that will utilize lignite and integrated gasification combined cycle technology, that has experienced material costs overruns and that represents a high degree of asset concentration for the utility.

For MidAmerican Energy Company, the absence of a fuel cost pass-through mechanism at the time of this writing results in its relatively low scoring on timeliness. However, the company has proposed a fuel clause in its current rate case, and the regulatory framework has generally been quite credit supportive, which has helped the utility generate good financial metrics.

The primary utility divisions of PacifiCorp have forward test years that have a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Outliers in Sufficiency of Rates and Returns

China Longyuan Power Group Corporation Ltd. has benefitted from a higher benchmark tariff for its wind power generation, balanced against a less well developed regulatory framework.

Outliers in Market Position

Okinawa Electric Power Company, Incorporated's service territory is a group of small islands with limited economic diversity, which negatively impacts its market position. Generation is highly dependent on coal and oil. These factors are balanced against a strong regulatory framework.

Outliers in Generation and Fuel Diversity

Ohio Power Company has been highly dependent on coal-fired generation but will be divesting generation assets in accordance with regulatory initiatives.

Outliers in Financial Strength

Distribuidora de Electricidad La Paz S.A. has strong historical financial metrics that are balanced against the somewhat unpredictable regulatory framework and the risk of government intervention in its business.

Gail (India) Limited has strong historical financial metrics that are balanced against higher business risk in its diversified, non-rate-regulated operations, including in oil and gas exploration and production. Financial metrics are expected to weaken somewhat relative to historical levels dne to debt funded capex and are thus expected to be more in line with its rating going forward.

Gas Natural BAN S.A. has strong historical financial metrics that are expected to deteriorate due to frozen tariff positions, reflected in weak scores for the regulatory environment. Its ratings are also impacted by debt matnrities that are concentrated in the short term and the Government of Argentina's B3 negative rating.

Appendix D: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structnre consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-ntility companies. Financing of these entities varies by region, in part due to the regnlatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in snbsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jnrisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[14] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utiliry family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity faciliry may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatns of external liquidiry or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

[14] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix E) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individnal results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity nnder more than one methodology. When non-ntility operations are less material but could still impact the overall credit profile, the difference in business risks and onr estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we cousider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposnres to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo nnder its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be cousidered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt. While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Currently, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, Energy Future Holdings Corp. (Caa3 senior unsecured) and its T&D subsidiary Oucor Electric Delivery Company LLC (Baa3 senior secured) have much wider notching due to the combiuation of regulatory imperatives and strong ring-fencing that includes a significaut minority shareholder who must agree to important corporate decisions, including a voluutary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to ratiug issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. Iu these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix E: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distributiou utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region. T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub-sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the fiual step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distiuguish LDCs from gas uetworks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas ntilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based ou the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology, and we expect that FERC-regulated transmission-only utilities in the US will also transition to the Regulated Networks when that methodology is updated (expected in 2014).

Utility Holding Company (Utility HoldCo): As detailed in Appendix D, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix F: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy. When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issners was curtailed dne to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a ntility from exposnre to price volatility of these fuels, bnt it does not insulate consumers. Consumers and regulators complained vociferously about utility rates dnring the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In mnch of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long-term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the cnrrent model under which electricity is generated and distributed to cnstomers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distribnting electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (np to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regnlatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers takiug electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distribnted generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be nnlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local ntility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions. Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for ntilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric ntility cnstomers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distribnted electric storage, could materially disrupt the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated (Ba3, negative), as well as all the nnclear utilities in the conntry. Japan previously generated abont 30% of its power from 50 reactors, bnt all are cnrrently either idled or shnt down, and utilities in the conntry face materially higher costs of replacement power, a credit negative. Japan also created a new Nuclear Regulation Authority (NRA), under the Ministry of the Environment to replace the Nnclear Safety Commission, which had been under the Ministry of Economy, Trade and Indnstry. The NRA has not yet set any schedule for completing safety checks at idled plants.

Fukushima Daiichi also had global conseqnences. Germany's response was to require that all nnclear power plants in the conntry be shut by 2022. Switzerland opted for a phase-ont by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nuclear license renewal decisions in the US are currently on hold until the Nuclear Regulatory Commission comes to a determination on the safety of spent fuel storage in the absence of a permanent repository. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. (Baa1, RUR-np) decided to permanently shut Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was permanently closed in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursne a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited (KHNP, A1 stable) and its parent Korea Electric Power Corporation (KEPCO, A1 stable), face a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be temporarily shut down starting in May 2013 and raises the risk the Korean public will lose confidence in nuclear power. However, more than 80% of substandard parts in the idled plants have been replaced, and a restart is expected in late 2013 or early 2014.

Appendix G: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers, February 2007), including a one notch differential between senior secured and senior unsecured debt. However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication Loss Given Default for Speculative-Grade Non-Financial Companies in the US, Canada and EMEA, June 2009).

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been uniqne to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The nse of securitization, a financing techniqne utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented secnritization frameworks include Arkansas, California, Connecticnt, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The ntility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, Moody's makes its own assessment of the appropriate credit representation bnt in most cases follows the accounting in audited statements under US Generally Accepted Acconnting Principles (GAAP), which is in turn considers the terms of enabling legislation. As a result, acconnting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even thongh it is technically non-recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it rednce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

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

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Moody's ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings (currently higher on average by about 2 notches), while utilities globally tend to be more evenly distributed above and below their actual ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

Appendix H: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While Moody's regards PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

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

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (snch that it is reported on the balance sheet, or disclosed as an operating lease and thus included in onr adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet. However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting pnrposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum Moody's treats a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. Moody's will particularly focus on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or we take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross-default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

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

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. Provided that the acconnting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the ntility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may nse a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

Industry Outlooks:

» US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)

» Asian Power Utilities (ex-Japan): Broad Stable Outlook; India an Outlier, March 2013 (149101)

Rating Methodologies:

» US Electric Generation & Transmission Cooperatives, April 2013, (151814)

» How Sovereign Credit Quality May Affect Other Ratings, February 2012 (139495)

» Unregulated Utilities and Power Companies, August 2009 (118508)

» Regulated Electric and Gas Networks, August 2009 (118786)

» Natural Gas Pipelines, November 2012 (146415)

» US Public Power Electric Utilities with Generation Ownership Exposure, November 2011 (135299)

» US Electric Generation & Transmission Cooperatives, April 2013 (151814)

» US Municipal Joint Action Agencies, October 2012 (145899)

» Government Related Issuers: Methodology Update, July 2010 (126031)

» Global Regulated Water Utilities, December 2009 (121311)

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

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

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MOODY'S
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LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 98

Witness: David S. Sinclair

Q-98. Provide the combined Companies' annual long-term peak and energy forecasts as prepared in each year since 2011.

A-98. See the table below. All amounts shown are after DSM.

	2012 LF		2013 LF		2014 LF	
	Energy (GWH)	Peak (MW)	Energy (GWH)	Peak (MW)	Energy (GWH)	Peak (MW)
2012	35,898	7,047				
2013	36,194	7,089	35,748	6,952		
2014	36,299	7,127	35,952	6,995	35,716	6,972
2015	36,582	7,165	36,162	7,040	35,892	7,028
2016	36,961	7,246	36,335	7,091	36,153	7,085
2017	37,268	7,289	36,503	7,147	36,383	7,142
2018	37,625	7,348	36,788	7,214	36,684	7,199
2019	37,981	7,398	37,101	7,282	36,998	7,257
2020	38,411	7,498	37,421	7,350	37,260	7,315
2021	38,718	7,540	37,669	7,418	37,479	7,374
2022	39,066	7,658	37,982	7,474	37,704	7,433
2023	39,406	7,704	38,323	7,540	37,922	7,488
2024	39,845	7,755	38,752	7,606	38,235	7,542
2025	40,215	7,836	39,083	7,673	38,478	7,598
2026	40,591	7,887	39,444	7,739	38,731	7,653
2027	40,992	7,975	39,806	7,806	38,990	7,709
2028	41,503	8,120	40,211	7,881	39,279	7,766
2029	41,986	8,213	40,582	7,957	39,543	7,822
2030	42,378	8,268	41,004	8,034	39,841	7,880
2031	42,836	8,382	41,364	8,111	40,084	7,937
2032	43,281	8,464	41,746	8,188	40,324	7,995
2033	43,804	8,635	42,140	8,257	40,596	8,054
2034	44,255	8,704	42,494	8,328	40,875	8,113
2035	44,761	8,807	42,894	8,398	41,162	8,172
2036	45,310	8,918	43,333	8,469	41,450	8,232
2037	45,833	9,012	43,740	8,541	41,663	8,292
2038	46,317	9,115	44,125	8,613	41,885	8,353
2039	46,825	9,285	44,518	8,685	42,111	8,414
2040	47,265	9,340	44,920	8,760	42,333	8,476
2041	47,902	9,141	45,338	8,834	42,556	8,538
2042			45,627	8,910	42,737	8,600
2043					42,893	8,663

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 99

Witness: David S. Sinclair

Q-99. Provide the combined Companies' actual coincident summer peak demand for each of the last 10 calendar years along with associated weather adjusted peak demands for each year if available.

A-99. See the table below for the combined Companies' summer peak demand for 2004-2013.

	Summer Peak Demand (MW)	WN Summer Peak Demand (MW)
2004	6,223	6,524
2005	6,833	6,791
2006	6,863	6,745
2007	7,132	6,876
2008	6,352	6,522
2009	6,367	6,518
2010	7,175	6,909
2011	6,756	6,694
2012	6,856	6,552
2013	6,434	6,480

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 100

Witness: David S. Sinclair

Q-100. Provide the combined Companies' actual annual native system energy sales for each of the last 10 calendar years along with associated weather adjusted peak demands for each year if available.

A-100. See table below for the combined Companies' actual annual native system energy sales for 2004-2013. These amounts are system energy requirements for Kentucky and Virginia, including wholesale municipals. See the response to Question No. 99 for weather adjusted peak demands.

	Energy Requirements After DSM (GWH)
2004	33,939
2005	35,377
2006	34,738
2007	36,387
2008	35,313
2009	33,600
2010	36,636
2011	34,755
2012	34,728
2013	35,042

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 101

Witness: David S. Sinclair

Q-101. Provide the combined Companies' actual monthly native system coincident peak demand and native system energy sales for each month since January of 2012.

A-101. See the table below for the combined Companies' actual monthly native system coincident peak demand and native system energy sales for each month since January of 2012. System energy sales amounts are system energy requirements for Kentucky and Virginia, including the wholesale municipal customers. Peak demand amounts are also for the total system, including Kentucky, Virginia, and the wholesale municipal customers

	Peak Demand (MW)	Energy Requirements After DSM (GWH)
Jan-2012	5,704	3,072
Feb-2012	5,395	2,754
Mar-2012	4,851	2,618
Apr-2012	4,756	2,441
May-2012	5,767	2,950
Jun-2012	6,856	3,092
Jul-2012	6,816	3,614
Aug-2012	6,603	3,327
Sep-2012	6,154	2,721
Oct-2012	4,499	2,570
Nov-2012	5,011	2,680
Dec-2012	5,264	2,888
Jan-2013	5,907	3,169
Feb-2013	5,901	2,838
Mar-2013	5,346	3,014
Apr-2013	4,540	2,515
May-2013	5,654	2,737
Jun-2013	6,288	2,995
Jul-2013	6,409	3,175
Aug-2013	6,333	3,260
Sep-2013	6,434	2,811
Oct-2013	5,235	2,658
Nov-2013	5,165	2,771
Dec-2013	5,721	3,098
Jan-2014	7,114	3,632
Feb-2014	6,290	3,024

	Peak Demand (MW)	Native System Sales (GWH)
Jan-2012	5,704	3,072
Feb-2012	5,395	2,754
Mar-2012	4,851	2,618
Apr-2012	4,756	2,441
May-2012	5,767	2,950
Jun-2012	6,856	3,092
Jul-2012	6,816	3,614
Aug-2012	6,603	3,327
Sep-2012	6,154	2,721
Oct-2012	4,499	2,570
Nov-2012	5,011	2,680
Dec-2012	5,264	2,888
Jan-2013	5,907	3,169
Feb-2013	5,901	2,838
Mar-2013	5,346	3,014
Apr-2013	4,540	2,515
May-2013	5,654	2,737
Jun-2013	6,288	2,995
Jul-2013	6,409	3,175
Aug-2013	6,333	3,260
Sep-2013	6,434	2,811
Oct-2013	5,235	2,658
Nov-2013	5,165	2,771
Dec-2013	5,721	3,098
Jan-2014	7,114	3,632
Feb-2014	6,290	3,024

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 102

Witness: David S. Sinclair

Q-102. Compare the 2013 base case peak demand forecast in this case to the base case peak demand forecast from the Companies 2011 IRP for years 2015 through 2025 and explain the major reasons why the 2013 forecast is significantly lower than the 2011 IRP forecast.

A-102. See the table below. All amounts shown are after DSM.

	2013 LF Peak Demand (MW)	2011 IRP Peak Demand (MW)	Difference
2015	7,040	7,059	(19)
2016	7,091	7,070	22
2017	7,147	7,135	13
2018	7,214	7,234	(20)
2019	7,282	7,393	(112)
2020	7,350	7,546	(196)
2021	7,418	7,616	(198)
2022	7,474	7,704	(230)
2023	7,540	7,819	(279)
2024	7,606	8,008	(402)
2025	7,673	8,156	(484)

The Companies have not analyzed the variances set forth in the table. However, the Companies disagree with the premise in the question that the 2013 forecast is significantly lower than the 2011 IRP forecast.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 103

Witness: John N. Voyles, Jr.

Q-103. Provide the following information for each generating unit owned by the Companies:

a. Commercial operation date,

b. Maximum Net Dependable Capacity Rating during summer,

c. Primary fuel type,

d. Annual net MWh generation for each of the last five years,

e. Annual average fuel cost ($/MWh) for each of the last five years

f. Scheduled retirement date,

g. Annual equivalent availability factor for each of the last five years, and

h. Annual average net heat rate (Btu/kWh) for each of the last five years.

A-103.

a.-h. See attached.

Station	Unit	Commercial Operation Date
		(Q.1.103.a.)
Brown	1	05/01/57
Brown	2	06/01/63
Brown	3	07/19/71
Brown	5	06/09/01
Brown	6	08/11/99
Brown	7	08/08/99
Brown	8	02/23/95
Brown	9	01/24/95
Brown	10	12/22/95
Brown	11	05/08/96
Cane Run	4	05/04/62
Cane Run	5	05/13/66
Cane Run	6	05/12/69
Cane Run	11	04/29/68
Dix Dam	1	11/24/25
Dix Dam	2	11/24/25
Dix Dam	3	11/24/25
Ghent	1	02/19/74
Ghent	2	04/20/77
Ghent	3	05/31/81
Ghent	4	08/18/84
Green River	3	04/06/54
Green River	4	07/08/59
Haefling	1	10/07/70
Haefling	2	10/21/70
Mill Creek	1	07/11/72
Mill Creek	2	06/11/74
Mill Creek	3	06/28/78
Mill Creek	4	07/15/82
Ohio Falls	1	01/01/28
Ohio Falls	2	01/01/28
Ohio Falls	3	01/01/28
Ohio Falls	4	01/01/28
Ohio Falls	5	01/01/28
Ohio Falls	6	01/01/28
Ohio Falls	7	01/01/28
Ohio Falls	8	01/01/28
Paddys Run	11	06/10/68
Paddys Run	12	07/16/68
Paddys Run	13	06/27/01
Trimble County	1	12/23/90
Trimble County	2	01/22/11
Trimble County	5	05/14/02
Trimble County	6	05/14/02
Trimble County	7	06/01/04
Trimble County	8	06/01/04
Trimble County	9	07/01/04
Trimble County	10	07/01/04
Zorn	1	05/23/69

Station	Unit	Maximum Net Demonstrated Capacity Summer 2014
		(Q.1.103.b.)
Brown	1	106
Brown	2	166
Brown	3	410
Brown	5	112
Brown	6	146
Brown	7	146
Brown	8	102
Brown	9	102
Brown	10	102
Brown	11	102
Cane Run	4	155
Cane Run	5	168
Cane Run	6	240
Cane Run	11	14
Dix Dam	1	8
Dix Dam	2	8
Dix Dam	3	8
Ghent	1	479
Ghent	2	495
Ghent	3	489
Ghent	4	469
Green River	3	68
Green River	4	93
Haefling	1	12
Haefling	2	12
Mill Creek	1	303
Mill Creek	2	301
Mill Creek	3	391
Mill Creek	4	477
Ohio Falls	1	6
Ohio Falls	2	6
Ohio Falls	3	6
Ohio Falls	4	6
Ohio Falls	5	8
Ohio Falls	6	8
Ohio Falls	7	8
Ohio Falls	8	6
Paddys Run	11	12
Paddys Run	12	23
Paddys Run	13	147
Trimble County	1	383
Trimble County	2	549
Trimble County	5	157
Trimble County	6	157
Trimble County	7	157
Trimble County	8	157
Trimble County	9	157
Trimble County	10	157
Zorn	1	14

Station	Unit	Primary Fuel Type (Q.1.103.c.)
Brown	1	coal
Brown	2	coal
Brown	3	coal
Brown	5	gas
Brown	6	gas
Brown	7	gas
Brown	8	gas
Brown	9	gas
Brown	10	gas
Brown	11	gas
Cane Run	4	coal
Cane Run	5	coal
Cane Run	6	coal
Cane Run	11	gas
Dix Dam	1	water
Dix Dam	2	water
Dix Dam	3	water
Ghent	1	coal
Ghent	2	coal
Ghent	3	coal
Ghent	4	coal
Green River	3	coal
Green River	4	coal
Haefling	1	gas
Haefling	2	gas
Mill Creek	1	coal
Mill Creek	2	coal
Mill Creek	3	coal
Mill Creek	4	coal
Ohio Falls	1	water
Ohio Falls	2	water
Ohio Falls	3	water
Ohio Falls	4	water
Ohio Falls	5	water
Ohio Falls	6	water
Ohio Falls	7	water
Ohio Falls	8	water
Paddys Run	11	gas
Paddys Run	12	gas
Paddys Run	13	gas
Trimble County	1	coal
Trimble County	2	coal
Trimble County	5	gas
Trimble County	6	gas
Trimble County	7	gas
Trimble County	8	gas
Trimble County	9	gas
Trimble County	10	gas
Zorn	1	gas

Station	Unit	Net Generation (MWh) 2009	Net Generation (MWh) 2010	Net Generation (MWh) 2011	Net Generation (MWh) 2012	Net Generation (MWh) 2013
		(Q 1 103 d)	(Q 1 103 d)	(Q 1 103 d)	(Q 1 103 d)	(Q 1 103 d)
Brown	1	217,008	411,311	317,251	324,035	378,905
Brown	2	547,458	763,280	616,832	721,085	875,868
Brown	3	1,740,829	1,828,361	1,563,842	1,323,503	1,599,792
Brown	5	2,380	8,061	3,634	6,618	3,382
Brown	6	36,780	48,131	28,481	127,748	50,307
Brown	7	26,632	46,851	33,892	95,198	42,879
Brown	8	7,658	7,864	4,340	2,561	2,834
Brown	9	1,509	5,196	4,718	7,403	5,316
Brown	10	2,370	4,365	1,741	2,188	875
Brown	11	4,551	8,529	1,301	5,671	1,299
Cane Run	4	947,128	927,127	967,087	653,192	696,743
Cane Run	5	952,330	1,110,385	952,048	928,589	864,302
Cane Run	6	1,335,527	1,233,866	1,287,984	1,084,657	995,291
Cane Run	11	210	228	198	296	200
Dix Dam	1	28,654	15,173	33,650	13,582	26,593
Dix Dam	2	32,019	14,736	13,098	5,416	39,906
Dix Dam	3	7,898	6,012	34,236	18,728	40,124
Ghent	1	2,867,642	3,295,876	3,394,813	3,166,600	3,298,654
Ghent	2	2,413,738	3,201,480	3,346,081	3,053,242	3,513,063
Ghent	3	3,182,388	3,431,840	2,866,840	3,333,292	3,294,839
Ghent	4	2,881,867	2,667,176	2,899,005	2,653,566	3,011,140
Green River	3	216,618	345,263	329,516	270,552	310,970
Green River	4	408,851	544,049	458,964	635,128	652,894
Haefling	1	(136)	175	143	585	383
Haefling	2	(147)	193	167	326	37
Mill Creek	1	2,106,620	2,009,037	2,044,329	2,016,171	1,466,563
Mill Creek	2	1,847,309	2,101,040	1,980,508	1,452,211	1,898,669
Mill Creek	3	2,786,525	2,914,876	1,875,925	2,611,560	2,212,407
Mill Creek	4	3,562,608	3,348,610	3,163,052	2,281,218	2,709,274
Ohio Falls	1	14,442	16,315	14,285	4,852	0
Ohio Falls	2	18,324	22,157	18,257	12,466	1,258
Ohio Falls	3	27,760	21,876	15,804	3,906	26,932
Ohio Falls	4	29,682	36,320	33,599	25,974	30,840
Ohio Falls	5	0	0	0	40,352	35,715
Ohio Falls	6	47,707	53,248	46,812	48,320	28,041
Ohio Falls	7	50,786	56,181	48,324	46,337	49,328
Ohio Falls	8	44,297	34,505	33,726	30,662	23,872
Paddys Run	11	12	279	95	221	(38)
Paddys Run	12	0	76	(272)	340	(182)
Paddys Run	13	1,247	14,831	31,411	56,710	29,267
Trimble County	1	2,300,055	2,722,317	2,410,890	2,899,985	2,604,629
Trimble County	2	-,---	-,---	3,116,818	2,506,228	3,140,516
Trimble County	5	43,455	129,011	59,355	226,311	66,372
Trimble County	6	28,243	100,288	66,423	259,618	89,149
Trimble County	7	39,368	108,211	72,925	100,026	72,123
Trimble County	8	33,230	98,266	54,521	102,009	27,346
Trimble County	9	29,731	125,065	75,141	259,734	84,647
Trimble County	10	21,366	103,882	47,533	86,050	26,433
Zorn	1	216	198	(74)	649	212

Note: Negative net values for minimally operated unit's indicate that the unit's aux power use exceeded the power actually generated.

Station	Unit	Average Fuel Cost ($/MWh) 2009 (Q 1 103 e)	Average Fuel Cost ($/MWh) 2010 (Q 1 103 e)	Average Fuel Cost ($/MWh) 2011 (Q 1 103 e)	Average Fuel Cost ($/MWh) 2012 (Q 1 103 e)	Average Fuel Cost ($/MWh) 2013 (Q 1 103 e)
Brown	1	39.41	38.37	39.99	38.67	38.01
Brown	2	34.61	35.18	37.55	34.55	33.33
Brown	3	34.44	37.57	38.23	35.79	35.17
Brown	5	159.83	88.83	106.16	54.77	99.12
Brown	6	76.00	146.37	76.32	33.14	51.67
Brown	7	70.48	75.35	77.01	34.72	49.64
Brown	8	97.10	109.93	150.03	64.94	81.17
Brown	9	170.32	104.38	139.73	51.59	78.94
Brown	10	167.87	113.33	132.87	76.99	153.70
Brown	11	125.69	91.52	129.32	53.15	157.80
Cane Run	4	20.30	23.75	23.76	28.16	26.86
Cane Run	5	19.81	22.18	22.11	25.08	24.76
Cane Run	6	19.95	22.29	22.18	24.87	24.78
Cane Run	11	294.29	359.29	234.42	465.53	669.38
Dix Dam	1	--.--	--.--	--.--	--.--	--.--
Dix Dam	2	--.--	--.--	--.--	--.--	--.--
Dix Dam	3	--.--	--.--	--.--	--.--	--.--
Ghent	1	25.58	23.19	23.61	24.45	23.65
Ghent	2	27.78	23.28	24.57	24.09	23.46
Ghent	3	27.50	24.48	24.49	24.85	24.56
Ghent	4	27.42	25.35	25.15	26.08	24.84
Green River	3	33.42	32.20	33.91	37.20	33.25
Green River	4	31.08	30.05	31.18	29.97	28.45
Haefling	1	--.--	260.13	399.02	121.61	153.50
Haefling	2	--.--	252.76	400.68	154.12	530.50
Mill Creek	1	19.50	20.01	21.46	25.06	25.96
Mill Creek	2	20.16	20.24	22.50	25.91	25.95
Mill Creek	3	19.55	20.12	22.20	24.93	26.08
Mill Creek	4	19.28	19.85	21.78	25.97	26.77
Ohio Falls	1	--.--	--.--	--.--	--.--	--.--
Ohio Falls	2	--.--	--.--	--.--	--.--	--.--
Ohio Falls	3	--.--	--.--	--.--	--.--	--.--
Ohio Falls	4	--.--	--.--	--.--	--.--	--.--
Ohio Falls	5	--.--	--.--	--.--	--.--	--.--
Ohio Falls	6	--.--	--.--	--.--	--.--	--.--
Ohio Falls	7	--.--	--.--	--.--	--.--	--.--
Ohio Falls	8	--.--	--.--	--.--	--.--	--.--
Paddys Run	11	10,730.67	5,028.43	--.--	645.83	--.--
Paddys Run	12	10,730.67	5,028.43	--.--	645.83	--.--
Paddys Run	13	89.48	99.67	84.14	50.71	73.41
Trimble County	1	21.71	23.68	24.06	24.88	26.02
Trimble County	2	--.--	--.--	22.25	24.16	23.66
Trimble County	5	91.91	68.73	110.35	44.12	105.01
Trimble County	6	123.77	67.94	93.88	45.61	101.16
Trimble County	7	91.16	77.77	96.39	66.27	97.04
Trimble County	8	117.35	70.56	105.92	47.93	96.99
Trimble County	9	97.04	71.67	102.29	42.14	100.92
Trimble County	10	107.41	70.02	118.16	43.67	95.76
Zorn	1	102.87	245.51	--.--	66.67	111.78

Note: Average fuel costs reflect unit starts, flame stabilization, and operation. For minimally operated units start fuel can be significant while megawatt-hours produced can be quite small. In these instances it is not uncommon for the math to produce high average costs.

Station	Unit	Scheduled Retirement Date
		(Q.1.103 f.)
Brown	1	na
Brown	2	na
Brown	3	na
Brown	5	na
Brown	6	na
Brown	7	na
Brown	8	na
Brown	9	na
Brown	10	na
Brown	11	na
Cane Run	4	05/01/15
Cane Run	5	05/01/15
Cane Run	6	05/01/15
Cane Run	11	na
Dix Dam	1	na
Dix Dam	2	na
Dix Dam	3	na
Ghent	1	na
Ghent	2	na
Ghent	3	na
Ghent	4	na
Green River	3	04/16/15
Green River	4	04/16/15
Haefling	1	na
Haefling	2	na
Mill Creek	1	na
Mill Creek	2	na
Mill Creek	3	na
Mill Creek	4	na
Ohio Falls	1	na
Ohio Falls	2	na
Ohio Falls	3	na
Ohio Falls	4	na
Ohio Falls	5	na
Ohio Falls	6	na
Ohio Falls	7	na
Ohio Falls	8	na
Paddys Run	11	na
Paddys Run	12	na
Paddys Run	13	na
Trimble County	1	na
Trimble County	2	na
Trimble County	5	na
Trimble County	6	na
Trimble County	7	na
Trimble County	8	na
Trimble County	9	na
Trimble County	10	na
Zorn	1	na

Station	Unit	Equiv. Avail. Factor (%) 2009 (Q.1.103.g.)	Equiv. Avail. Factor (%) 2010 (Q.1.103.g.)	Equiv. Avail. Factor (%) 2011 (Q.1.103.g.)	Equiv. Avail. Factor (%) 2012 (Q.1.103.g.)	Equiv. Avail. Factor (%) 2013 (Q.1.103.g.)
Brown	1	84.1	85.3	90.9	86.4	91.0
Brown	2	78.1	84.9	82.5	89.6	88.8
Brown	3	78.9	79.3	88.0	74.0	78.5
Brown	5	97.6	81.5	96.4	95.3	98.1
Brown	6	70.3	55.8	95.9	95.5	97.3
Brown	7	92.5	96.0	94.2	97.1	97.4
Brown	8	96.5	99.7	98.4	96.8	95.8
Brown	9	98.4	99.3	98.7	96.8	81.9
Brown	10	98.5	93.3	99.5	96.0	99.1
Brown	11	99.2	90.8	99.8	97.6	82.1
Cane Run	4	87.1	82.7	93.5	79.4	72.9
Cane Run	5	89.3	93.7	87.2	88.0	86.6
Cane Run	6	82.4	72.5	91.0	78.1	81.9
Cane Run	11	98.4	99.7	68.1	98.5	98.9
Dix Dam	1	63.9	96.4	89.6	46.1	76.6
Dix Dam	2	83.2	95.2	28.9	36.0	94.9
Dix Dam	3	25.9	65.1	87.9	90.2	95.1
Ghent	1	79.7	87.0	90.7	81.2	91.1
Ghent	2	76.3	94.5	94.6	79.7	94.5
Ghent	3	88.3	90.8	80.1	87.0	86.6
Ghent	4	89.9	75.3	90.3	86.4	84.7
Green River	3	86.5	80.0	96.6	89.3	96.6
Green River	4	81.3	91.5	75.4	88.9	86.5
Haefling	1	59.6	90.3	87.0	97.4	97.8
Haefling	2	80.3	98.7	86.5	98.3	97.5
Mill Creek	1	92.0	84.3	87.8	91.6	70.4
Mill Creek	2	83.9	88.7	87.4	71.1	88.5
Mill Creek	3	87.1	89.3	60.2	90.2	75.4
Mill Creek	4	91.8	83.2	81.8	66.1	80.5
Ohio Falls	1	34.7	37.6	36.5	14.9	0.0
Ohio Falls	2	40.0	43.4	37.2	22.2	2.1
Ohio Falls	3	56.2	35.5	27.7	8.8	36.3
Ohio Falls	4	52.0	55.0	52.1	43.6	58.2
Ohio Falls	5	0.0	0.0	0.0	70.7	53.2
Ohio Falls	6	69.2	68.8	59.7	64.7	43.3
Ohio Falls	7	71.0	70.8	61.5	61.5	69.9
Ohio Falls	8	70.6	50.9	51.0	46.2	39.4
Paddys Run	11	99.1	95.0	82.6	72.8	94.5
Paddys Run	12	99.0	77.7	60.2	84.7	95.0
Paddys Run	13	97.5	72.9	61.3	82.5	83.3
Trimble County	1	73.5	87.4	78.5	91.9	85.6
Trimble County	2	--.-	--.-	71.5	52.4	66.4
Trimble County	5	99.4	91.0	80.9	96.6	97.3
Trimble County	6	94.2	65.7	97.8	96.9	98.1
Trimble County	7	99.2	97.6	99.4	82.4	98.0
Trimble County	8	99.4	95.5	84.2	96.4	93.0
Trimble County	9	90.5	97.4	98.1	83.2	97.8
Trimble County	10	98.2	96.7	98.1	98.3	82.4
Zorn	1	62.8	99.7	69.4	81.3	99.7

Station	Unit	Average Net Heat Rate (Btu/Kwh) 2009	Average Net Heat Rate (Btu/Kwh) 2010	Average Net Heat Rate (Btu/Kwh) 2011	Average Net Heat Rate (Btu/Kwh) 2012	Average Net Heat Rate (Btu/Kwh) 2013
		(Q.1.103.h.)	(Q.1.103.h.)	(Q.1.103 h.)	(Q.1 103.h.)	(Q.1.103.h.)
Brown	1	11,682	11,064	12,021	12,092	12,026
Brown	2	10,414	10,293	10,825	10,710	10,457
Brown	3	10,534	10,815	11,154	11,267	11,308
Brown	5	23,867	17,401	24,738	18,529	24,324
Brown	6	12,583	13,095	14,822	11,507	9,689
Brown	7	11,546	13,698	12,977	11,560	12,117
Brown	8	17,357	17,650	20,569	21,175	20,979
Brown	9	28,521	19,671	22,337	17,585	17,924
Brown	10	20,463	20,873	31,003	23,499	38,448
Brown	11	18,038	11,418	38,470	18,458	31,950
Cane Run	4	10,830	10,418	10,602	11,764	11,556
Cane Run	5	10,648	10,748	10,720	10,713	10,858
Cane Run	6	10,823	10,718	10,593	11,286	10,841
Cane Run	11	20,943	144,188	21,328	28,638	38,642
Dix Dam	1	--,---	--,---	--,---	--,---	--,---
Dix Dam	2	--,---	--,---	--,---	--,---	--,---
Dix Dam	3	--,---	--,---	--,---	--,---	--,---
Ghent	1	10,437	10,329	10,413	10,705	10,784
Ghent	2	10,465	10,399	10,905	10,608	10,696
Ghent	3	11,131	10,801	10,768	10,905	11,080
Ghent	4	10,988	10,887	10,900	11,156	11,051
Green River	3	11,942	11,929	12,426	14,058	13,154
Green River	4	11,278	11,043	11,485	11,668	11,311
Haefling	1	--,---	--,---	--,---	--,---	--,---
Haefling	2	--,---	--,---	--,---	--,---	--,---
Mill Creek	1	10,639	10,684	10,622	10,607	10,658
Mill Creek	2	10,928	10,845	11,075	10,867	10,672
Mill Creek	3	10,619	10,738	10,602	10,436	10,504
Mill Creek	4	10,410	10,518	10,616	10,735	10,827
Ohio Falls	1	--,---	--,---	--,---	--,---	--,---
Ohio Falls	2	--,---	--,---	--,---	--,---	--,---
Ohio Falls	3	--,---	--,---	--,---	--,---	--,---
Ohio Falls	4	--,---	--,---	--,---	--,---	--,---
Ohio Falls	5	--,---	--,---	--,---	--,---	--,---
Ohio Falls	6	--,---	--,---	--,---	--,---	--,---
Ohio Falls	7	--,---	--,---	--,---	--,---	--,---
Ohio Falls	8	--,---	--,---	--,---	--,---	--,---
Paddys Run	11	151,188	42,947	74,663	43,968	--,---
Paddys Run	12	--,---	55,026	67,019	49,351	--,---
Paddys Run	13	11,886	10,956	11,100	11,571	11,355
Trimble County	1	10,554	10,695	10,665	10,705	10,763
Trimble County	2	--,---	--,---	9,560	9,435	9,359
Trimble County	5	11,833	11,529	10,925	11,178	13,196
Trimble County	6	12,592	11,766	11,576	11,188	12,975
Trimble County	7	10,809	14,835	10,560	11,819	13,033
Trimble County	8	12,222	11,755	10,861	11,352	12,653
Trimble County	9	12,346	11,678	11,057	10,589	13,659
Trimble County	10	13,512	11,570	10,720	11,533	10,680
Zorn	1	16,419	22,881	--,---	20,911	25,818

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Question No. 104

Witness: David S. Sinclair

Q-104. Provide the current normal dispatch order of the Companies' supply resources assuming each resource is available and indicate where the Cane Run and proposed Green River NGCC project will likely fit within the dispatch order.

A-104. The dispatch order will vary depending on the price of natural gas and coal. The dispatch order based on current coal and natural gas prices is provided in the table below.

Dispatch Order	Unit
1	Hydro (Ohio Falls and Dix Dam)
2	Trimble County 2
3	Green River 4
4	Mill Creek 2
5	Trimble County 1
6	Ghent 2
7	Mill Creek 1
8	Mill Creek 3
9	Mill Creek 4
10	Cane Run 5
11	Ghent 1
12	Ghent 3
13	Ghent 4
14	OVEC
15	Cane Run 6
16	Brown 2
17	Cane Run 4
18	Brown 1
19	Brown 3
20	Green River 3
21	Green River 5

22	Cane Run 7
23	Trimble County 5
24	Trimble County 6
25	Trimble County 7
26	Trimble County 8
27	Trimble County 9
28	Trimble County 10
29	Brown 6
30	Brown 7
31	Paddy's Run 13
32	Brown 5
33	Brown 9
34	Brown 10
35	Brown 8
36	Brown 11
37	Cane Run 11
38	Paddy's Run 11
39	Zorn 1
40	Paddy's Run 12
41	Haefling

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Question No. 105

Witness: John N. Voyles, Jr.

Q-105. Identify any must-run generating resources and provide operating policies that address the specific operating constraints applied to such units.

A-105. The Companies do not have any must-run generating resources.

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Question No. 106

Witnesses: John N. Voyles, Jr.

Q-106. Provide firm transmission import limits into the Companies' system and discuss the extent to which transmission constraints presently impact reliability of service to Kentucky ratepayers.

A-106. The Companies' transmission system has firm import capability from MISO, PJM, TVA, and OVEC. The chart below displays minimum and maximum effective Available Transfer Capability (ATC) as posted on the Companies' OASIS as of 3/18/2014. Beyond 18 months out, ATC limits are unknown and an OATT study would be required to calculate them based on specific resources and transmission paths.

:

POR to POD	Summer 2014 (min/max)	Winter 2014/15 (min/max)
MISO to LGEE	823/3,393	1,842/3,054
OVEC to LGEE	843/1,196	1,196/1,493
PJM to LGEE	858/2,850	2,580/3,159
TVA to LGEE	1,051/2,005	1,968/2,198

*These values presume capacity is available to be imported from these sources.

** These values presume Available Transfer Capability on the sources transmission system is available to export to the Companies' Transmission System.

Based on the current Companies' transmission system and existing import firm effective ATC, there are no transmission reliability constraints that negatively impact the Companies' ratepayers. However, real-time risk conditions may present changes to the transmission system, which could impact reliability of service within the region, where the generator is being proposed. See the response to Question No.33 for further clarification.

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Question No. 107

Witness: John N. Voyles, Jr.

Q-107. Provide the Companies' most recent long-term transmission planning study and identify major transmission projects which are planned to be constructed within the Companies' Kentucky service area over the next seven years.

A-107. The attached table lists transmission projects planned over the next seven years which are the most recently approved by the ITO for the Companies. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

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Question No. 108

Witness: David S. Sinclair

Q-108. Provide the total combined system energy supply mix by primary fuel type and including renewable resources and market energy purchases for each of the last three calendar years

A-108. See table below (values are in MWh).

Energy Supply Mix (%)	2011	2012	2013
Primary Fuel			
Coal	94.0%	91.5%	95.0%
Gas	1.4%	3.8%	1.4%
	95.3%	**95.4%**	**96.4%**
Renewable			
Hydro	0.8%	0.7%	0.9%
	0.8%	**0.7%**	**0.9%**
Purchases			
OVEC	3.2%	3.2%	3.2%
Market	0.7%	0.7%	0.7%
	3.8%	**3.9%**	**3.8%**
Total Supply	**100.0%**	**100.0%**	**100.0%**

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Case No. 2014-00002

Question No. 109

Witness: David S. Sinclair

Q-109. Provide summaries of each existing long-term (one-year or more) firm purchased power contracts, including:

a. Counterparty,

b. Term,

c. Annual capacity (MW) and energy purchased,

d. Capacity prices for remaining term of contract, and

e. Energy prices for remaining term of contract.

A-109.

a. The Companies have purchase agreements in place with Ohio Valley Electric Corporation ("OVEC").

b. The term of the agreement is the life of the Kyger and Clifty Creek plants.

c. In total, the Companies receive 8.13 percent of the OVEC capacity and energy. This equates to 172 MW at the time of summer peak.

d. and e. The purchase agreement does not specify capacity and energy prices. Instead, the Companies pay their share of fixed and variable costs of OVEC.

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Question No. 110

Witness: David S. Sinclair

Q-110. Provide summaries of each short-term (less than one-year) firm capacity purchase, for each of the last three calendar years and for 2014, including:

a. Counterparty,

b. Term,

c. Monthly capacity (MW) and energy purchased,

d. Capacity prices ($/kW-mo), and

e. Energy prices for ($/MWh).

A-110. The Companies have not purchased short-term firm capacity in the last three calendar years or in 2014.

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Question No. 111

Witness: David S. Sinclair

Q-111. Provide the volume (MWh) and average price ($/MWh) of market energy purchases for the combined Companies during on-peak hours for each month since January of 2012.

A-111. The following table contains the requested volume (MWh) and average price ($/MWh) of market energy purchases for the combined Companies during on-peak hours since January of 2012. Market purchases do not include ownership, imbalance, or payback purchases (Ohio Valley Electric Corporation, Transmission Owner, or Independent Power Producers).

Market Purchases								
	Peak	Average Price		Peak	Average Price		Peak	Average Price
Jan-12	-	$ -	Jan-13	27,493	$ 32.22	Jan-14	2,238	$ 522.19
Feb-12	100	$ 19.00	Feb-13	3,843	$ 33.71	Feb-14	900	$ 37.61
Mar-12	4,364	$ 27.26	Mar-13	8,344	$ 38.78			
Apr-12	10,549	$ 31.40	Apr-13	7,900	$ 36.69			
May-12	62,090	$ 46.15	May-13	425	$ 33.18			
Jun-12	14,085	$ 47.14	Jun-13	264	$ 46.78			
Jul-12	45,387	$ 68.08	Jul-13	1,050	$ 178.53			
Aug-12	26,258	$ 53.84	Aug-13	150	$ 33.06			
Sep-12	12,817	$ 34.84	Sep-13	888	$ 37.57			
Oct-12	17,238	$ 38.43	Oct-13	3,900	$ 29.90			
Nov-12	603	$ 30.72	Nov-13	752	$ 47.22			
Dec-12	19,497	$ 28.83	Dec-13	1,200	$ 17.00			

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Case No. 2014-00002

Question No. 112

Witness: David S. Sinclair

Q-112. Provide the volume (MWh) and average price ($/MWh) of market energy purchases for the combined Companies during off-peak hours for each month since January of 2012.

A-112. The following table contains the requested volume (MWh) and average price ($/MWh) of market energy purchases for the combined Companies during off-peak hours since January of 2012. For purposes of this response and consistent with industry practice, off-peak has been assumed to also include weekend hours. Market purchases do not include ownership, imbalance, or payback purchases (Ohio Valley Electric Corporation, Transmission Owner, or Independent Power Producers).

Market Purchases								
	O+W	Average Price		O+W	Average Price		O+W	Average Price
Jan-12	-	$ -	Jan-13	6,027	$ 23.47	Jan-14	550	$ 26.10
Feb-12	1,351	$ 22.54	Feb-13	1,453	$ 16.72	Feb-14	-	$ -
Mar-12	12,180	$ 19.09	Mar-13	1,650	$ 39.39			
Apr-12	31,351	$ 20.62	Apr-13	10,917	$ 28.28			
May-12	89,013	$ 24.72	May-13	3,500	$ 18.46			
Jun-12	9,225	$ 20.41	Jun-13	550	$ 17.18			
Jul-12	1,920	$ 75.00	Jul-13	1,300	$ 26.08			
Aug-12	-	$ -	Aug-13	650	$ 32.56			
Sep-12	916	$ 41.75	Sep-13	-	$ -			
Oct-12	1,100	$ 20.18	Oct-13	5,100	$ 19.60			
Nov-12	2,528	$ 30.44	Nov-13	1,738	$ 28.70			
Dec-12	16,791	$ 28.00	Dec-13	1,100	$ 17.73			

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Question No. 113

Witness: David S. Sinclair

Q-113. Provide the volume (MWh) and average price ($/MWh) of off-system sales for the combined Companies for each month since January of 2012.

A-113. The following table contains the requested volume (MWh) and average price ($/MWh) of off-system sales for the combined Companies since January of 2012.

	2012		2013		2014	
	Volume (MWh)	Avg. Price ($/MWh)	Volume (MWh)	Avg. Price ($/MWh)	Volume (MWh)	Avg. Price ($/MWh)
Jan	96,359	36.04	55,050	46.45	87,691	113.80
Feb	14,115	38.65	24,405	39.67	76,849	64.18
Mar	19,119	41.90	10,959	43.91	--	--
Apr	18,319	36.08	14,435	38.57	--	--
May	12,281	40.42	73,045	42.37	--	--
Jun	18,663	48.86	53,638	44.86	--	--
Jul	33,804	60.34	52,898	49.61	--	--
Aug	15,063	52.68	22,543	43.60	--	--
Sep	28,990	42.50	14,327	51.19	--	--
Oct	58,426	38.47	49,177	39.13	--	--
Nov	76,432	39.71	34,687	37.89	--	--
Dec	24,511	33.29	97,368	40.36	--	--

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Question No. 114

Witness: David S. Sinclair

Q-114. Provide the basis for the assumed reserve margin levels used to assess the Companies forecasted need for capacity.

A-114. The reserve margin analysis was performed as part of the 2011 Integrated Resource Plan ("2011 IRP"), filed with the Commission in April 2011 in Case No. 2011-00140. Refer to this document for the requested information.

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Question No. 115

Witness: David S. Sinclair

Q-115. Provide the planning reserve margin level (%) used for the Companies' 2011 IRP and Cane Run NGCC analysis.

A-115. In the 2011 IRP and Cane Run NGCC analysis, the Companies' utilized a planning reserve margin range of 15-17%.

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Question No. 116

Witness: David S. Sinclair

Q-116. Provide the current long-term forecast of peak demand and capacity reserve levels for MISO.

A-116. A discussion of MISO's current peak demand and capacity reserve levels can be found in the publicly available document "NERC 2013 Long- Term Reliability Assessment", December 2013, starting on page 52, which is available at the following link:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

Additional detail including all annual values for peak demand and capacity reserve levels through 2023 can be found by filtering on 'Year" as 2013 and 'Assessment Area' as MISO in the workbook "Capacity & Demand 2011-2013.xls", tab 'Schedule 3a' also publicly available on the NERC website:

http://www.nerc.com/pa/RAPA/ESD/Documents/ES_D_2013.zip

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Question No. 117

Witness: David S. Sinclair

Q-117. Reference Exhibit DSS-1, page 14, provide the Synapse Energy Economics report from which the referenced Mid CO_2 price forecast was derived.

A-117. See Exhibit DSS-1 at page 13, footnote 18. The Synapse report is available at http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

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Question No. 118

Witness: David S. Sinclair

Q-118. Explain why Synapse Energy Economics forecast was selected as the basis for the Companies' Mid CO_2 price forecast.

A-118. See the response to Question Nos. 36 and 78.

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Question No. 119

Witness: David S. Sinclair

Q-119. Provide any other CO_2 price forecasts that were reviewed by the Companies in an effort to assess the reasonableness of the 2012 Synapse Energy Economics CO_2 forecast.

A-119. See the response to Question No. 78.

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Question No. 120

Witness: David S. Sinclair

Q-120. Provide any independent analysis conducted by the Companies to assess the reasonableness of the underlying assumptions and results of the Synapse Energy Economics CO_2 forecast.

A-120. See the response to Question No. 78.

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Question No. 121

Witness: David S. Sinclair

Q-121. Provide the CO_2 forecasts used for the Companies' most recent IRP analysis and for the analysis of the new Cane Run NGCC facility.

A-121. CO_2 prices were not analyzed in the Companies' 2011 IRP nor were they considered in the analysis of the Cane Run NGCC facility.

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Question No. 122

Witness: David S. Sinclair

Q-122. Reference Mr. Sinclair's direct testimony, page 25, explain the basis for the assumed 0.5 likelihood assigned to the Mid CO_2 price forecast and provide any analysis supporting this assumption.

A-122. See Mr. Sinclair's testimony on page 26, lines 5-16.

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Question No. 123

Witness: David S. Sinclair

Q-123. Reference Mr. Sinclair's direct testimony, page 25, explain why CO_2 prices were included in the Companies' economic evaluation of the Green River NGCC project when there is not enough known about the potential for CO2 regulations to evaluate material changes to the Companies' existing generating fleet.

A-123. See the response to Question No. 38.

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Question No. 124

Witness: David S. Sinclair

Q-124. Provide the Companies' testimony from the Cane Run CCN case addressing forecasted CO_2 prices used for the analysis supporting the Can Run NGCC facility.

A-124. See the response to Question No. 121.

See also http://psc.ky.gov/PSCSCF/2011%20cases/2011-00375/20120203_LGE%20and%20KUs%20Rebuttal%20Testimony%20of%20David%20Sinclair.pdf at page 16.

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Question No. 125

Witness: David S. Sinclair

Q-125. Reference Exhibit DSS-1, page 6, identify each of the 72 proposals which remain valid and which could still be selected as alternatives to the proposed Green River NGCC project. For proposals which are no longer valid, explain why they are no longer valid.

A-125. The 72 proposals originated from 29 parties. On December 20th, 2012, 6 parties were notified that they were on the short list for further consideration. On December 20th and 21st, 2012, the remaining 23 parties were informed that their proposals were not a potential low-cost solution to the RFP process. On October 3rd, 2013 the short listed parties were informed that their proposals were not a potential low-cost solution to the RFP process. At no time in the RFP process did any party make a proposal that was "binding." Instead, all proposals were subject to negotiation and the execution of mutually agreeable definitive documents. The Companies do not know if any of the proposals provided in the RFP would still be "valid" for consideration at this time.

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Question No. 126

Witness: David S. Sinclair

Q-126. Reference Exhibit DSS-1, page 16, provide a sample calculation illustrating the referenced imputed debt adjustment used for PPAs.

A-126. See attached.

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Question No. 127

Witness: Edwin R. Staton

Q-127. Reference Exhibit DSS-1, page 16, provide the specific Commission findings from the Companies' last rate case that address imputed debt adjustments for PPAs.

A-127. The Companies' last rate cases (Case Nos. 2012-00221 and 2012-00222) were settled by agreement of all parties. The Commission approved the parties' Settlement Agreement, but there was no specific treatment of imputed debt adjustments for PPAs in the Settlement Agreement or in the Commission's Order approving the Settlement Agreement. However, in the testimony of Daniel K. Arbough the Companies explain that imputed debt adjustments for PPAs are incorporated into the target capital structure calculations because they are included by the rating agencies in their determination of the Companies' credit ratings.

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Question No. 128

Witness: David S. Sinclair

Q-128. Reference Exhibit DSS-1, page 27, provide the PVRR of the imputed debt cost included for each PPA evaluated for each of the alternatives presented in Table 21.

A-128. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

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Question No. 129

Witness: David S. Sinclair

Q-129. Explain why no self-build simple cycle combustion turbine alternatives were evaluated as a potential alternative to the proposed Green River NGCC facility.

A-129. The Companies received proposals in the RFP from SCCT assets that were priced below the cost of new build. Therefore, there was no need to develop a self-build SCCT option. See Appendix A in Section 6.1 of Exhibit DSS-1.

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Question No. 130

Witness: David S. Sinclair

Q-130. Reference Exhibit DSS-1, page 16, provide capital and operating cost assumptions used for the analysis of the Green River NGCC and Cane Run NGCC facilities comparable to the figures presented in Table 10, and explain the basis for any differences between the LGR assumptions and the Green River and Cane Run assumptions.

A-130. See the tables below. The LGR and Green River NGCC cost assumptions are provided in 2018 dollars. The operating cost assumptions for Green River NGCC and the NGCC (2x1) LGR units are the same. The capital cost for the NGCC (2x1) LGR unit was developed initially as the estimated cost of a generic brownfield facility. This cost was later refined for Green River NGCC to be Green River site-specific.

LGR and Green River NGCC Cost Assumptions ($2018)

	Capacity (MW)	**Capital ($M)**	**Fixed O&M ($/MW-Yr)**	**Variable O&M ($/MWh)**	**Long-term Service Agreement**	**Start Fuel (mmBtu/start)**
NGCC (2x1)	670	634	7,801[1]	0.37	Greater of $937/operating hour or $25,902/start	3,019
Green River NGCC (2x1)	670	650.4	7,801[1]	0.37	Greater of $937/operating hour or $25,902/start	3,019

[1]In addition to this cost, a rotor replacement is assumed every 16 years at a cost of $40,400/MW.

The cost assumptions for Cane Run 7 are summarized below. Capital costs are taken from the 2011 Resource Assessment; all other assumptions are taken from the 2013 Resource Assessment. After adjusting for the time value of money, the capital costs of the two units are similar. Compared to the Green River unit, total fixed and non-fuel operating costs are assumed to be lower for the Cane Run unit. At an approximately 85% capacity factor, total fixed and non-fuel operating costs are approximately $14.5 million for the Green River NGCC unit (see the response to PSC 1-34). The comparable cost for Cane Run 7 is approximately $11.3 million.

Cane Run 7 Cost Assumptions

	Capacity (MW)	Capital ($M; Sum of Nominal As-Spent Dollars)	Fixed O&M ($/MW-Yr; $2018)	Variable O&M ($/MWh; $2018)	Long-term Service Agreement ($2018)	Start Fuel (mmBtu/start)
Cane Run NGCC (2x1)	640	583	6,951	0.05	Greater of $821/operating hour or $23,763/start	3,019

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Question No. 131

Witness: David S. Sinclair

Q-131. Reference Exhibit DSS-1, Appendix B, provide electronic models with underlying assumptions and calculations supporting the Phase 1 Screening Analysis results presented for each alternative.

A-131. See the response to PSC 1-22. The path and filename for the Phase 1 screening model is 02_Analysis\Phase1\20121102_PhaseIScreeningAnalysis_0073D08.xlsx.

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Question No. 132

Witness: Gary H. Revlett

Q-132. Reference Exhibit DSS-1, page 6, provide the specific regulations and analysis supporting the assumption that the Green River NGCC unit would be subject to operating constraints (120 starts per year) if it is commissioned after 2018, indicate whether this constraint was applied to all NGCC resources evaluated that were commissioned after 2018, and provide the estimated PVRR impact of this assumed constraint for each NGCC alternative evaluated.

A-132. Per 401 KAR 51:017, the look back period used in the PSD netting analysis is the highest two-year annual average during the previous five period, beginning with the date of commencing construction. Under the current construction plans it is clear that a full two-year period of emissions from the existing Green River coal-fired plant would be available for netting as demonstrated in the PSD air permit application. However, if construction is delayed beyond 2018, then a full two-year period of existing unit emissions will not be available during the previous 5-year period and additional operating constraints would be required.

Since there are greater emissions during startup of the unit, the additional operating constraints generally include fewer starts per year. Based on a previously permitted greenfield combined-cycle unit in Kentucky the number of starts per year was limited to 120.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 133

Witness: David S. Sinclair

Q-133. Reference Exhibit DSS-1, page 18, provide each of the referenced costs for each proposal evaluated in the Phase 1 screening analysis.

A-133. Most of the referenced costs are listed in Appendix A at page 49 of Exhibit DSS-1. All cost assumptions are available electronically in the Excel workbook referenced in the response to AG 1-131 (20121102_PhaseIScreeningAnalysis_0073D08.xlsx). The following table provides information regarding the location of each cost assumption in this file.

Phase 1 Screening Cost Assumptions

Phase 1 Screening Cost	**Worksheet Name**	**Notes**
Fuel/Energy Costs	FuelForecast	Up to three scenarios were modeled for each fuel type.
Start Costs	RFPInputs or OwnershipInputs	
Hourly Operating Cost	RFPInputs or OwnershipInputs	
Variable O&M	RFPInputs, Schedules, or OwnershipInputs	If variable O&M is not escalated at a constant rate, it is defined by a schedule (and the proposal's variable O&M is listed in the Schedules worksheet).
Unit Capital Costs	RFPInputs or Ownership Inputs	
Fixed O&M	RFPInputs or Schedules	If fixed O&M is not escalated at a constant rate, it is defined by a schedule (and the proposal's fixed O&M is listed in the Schedules worksheet).
Capacity Charge	RFPInputs or Schedules	If capacity charge is not escalated at a constant rate, it is defined by a schedule (and the proposal's capacity charge is listed in the Schedules worksheet).
Firm Transmission	Transmission	
Firm Gas Transportation	GasTransport	

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 134

Witness: David S. Sinclair

Q-134. Reference Exhibit DSS-1, page 19, explain why coal resources were evaluated using a maximum 65% capacity factor and provide any analysis or historical basis for this assumption.

A-134. With one exception, the coal units referenced in the RFP responses were older units that would likely be dispatched later in the dispatch order. The capacity factor for this type of unit would generally not be expected to exceed 65%. Regardless, because only similar proposals were evaluated against each other in the Phase 1 screening analysis (e.g., coal proposals were evaluated only against other coal proposals), the capacity factor assumption did not have a significant impact on the Phase 1 screening results. All 5-year coal PPAs and all viable proposals to sell coal units were evaluated in the more detailed Phase 2 analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 135

Witness: David S. Sinclair

Q-135. Reference Exhibit DSS-1, page 19, explain why NGCC resources were evaluated using a maximum 85% capacity factor and provide any analysis or historical basis for this assumption.

A-135. The maximum 85% capacity factor was selected because it reflects a reasonable long term capacity factor assuming low natural gas prices and normal maintenance outages. Because only similar proposals were evaluated against each other in the Phase 1 screening analysis, the capacity factor assumption did not have a significant impact on the Phase 1 screening results.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 136

Witness: David S. Sinclair

Q-136. Reference Mr. Sinclair's direct testimony, pages 17-18, identify the specific conditions which the FERC placed on the acquisition of the Bluegrass Generation project and provide analysis which supports the Companies' conclusion that such conditions made the acquisition uneconomical.

A-136. See the response to PSC 1-15.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 137

Witness: David S. Sinclair

Q-137. Reference Mr. Sinclair's direct testimony, page 28, provide the referenced study and resultant cost estimate for the Brown Solar Facility.

A-137. HDR's conceptual siting study for the Brown Solar Facility is attached.

PPL companies

E.W. Brown 10 MW PV Solar Siting Study

February 11, 2014

HDR Project No. 221566

Revision A

Client Review Issue

Table of Contents

APPENDICES

E.W. BROWN 10 MW PV SOLAR SITING STUDY

1.0 EXECUTIVE SUMMARY

LG&E and KU Services Company (LG&E/KU) is conducting an evaluation of photovoltaic (PV) solar technology options applied for implementation of a 10 MW AC PV solar facility located at the E.W. Brown Generating Station which include:

- Fixed Tilt Thin Film Technology
- Fixed Tilt Multicrystalline Standard Efficiency Technology (300 W panel)
- Fixed Tilt Multicrystalline High Efficiency Technology (315+ W panel)
- Single Axis Tracking Thin Film Technology
- Single Axis Multicrystalline Standard Efficiency Technology (300 Watt panel)
- Single Axis Multicrystalline High Efficiency Technology (320+ Watt panel)

The proposed project site is the former Thurman Hardin Estate, a 152 acre parcel currently owned by LG&E-KU located adjacent to the E. W. Brown Station. The parcel consists primarily of rolling open field with several structures constructed.

The 13.2 kV CCRT E. W. Brown auxiliary power system currently planned will be utilized for the interconnection point and transmission system capacity.

A technology feasibility and economic evaluation was performed to determine the solar PV application most suitable for the project site and providing the lowest cost of generation. Prior to formal evaluation, the site topography slopes were determined to not be practical to construct single axis tracking systems. The site east/west slopes of 5% to 20% far exceed east/west maximum slope requirements of 2%.

The analysis was conducted based on fixed tilt systems employing thin film, standard efficiency multicrystalline and high efficiency multicrystalline module technology. A contour type mounting system is required to support an installation on the site terrain with a reasonable degree of site work. The maximum east/west slope criteria established for placement of the three module technologies is 12%. The analysis concluded the site can support the targeted 10 MW AC capacity utilizing standard efficiency and high efficiency multicrystalline modules. The nominal 50 acres of site suitable for solar module installation can support only 6.5 MW AC of thin film solar PV due to the low power density of the technology.

HDR modeled the generation of the three technologies plant using PVSYST solar modeling software, which is a widely utilized industry generation estimation tool. PVSYS applies hourly historic meteorological data that has been gathered to estimate the electric production of a PV system, based on specific OEM module performance at site conditions. Plant capital costs were developed to determine generation costs based on the MWHR production calculated for each option.

A summary of the capital costs and corresponding calculated cost of generation is provided in Table 1. Please note the thin film technology alternative is based on a nominal 6.5 MW AC.

Table 1
Capital Cost and Cost of Generation Summary

Description	Thin Film (6.5 MW AC)	Standard Efficiency	High Efficiency
EPC Direct Cost			
Site Preparation	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**
Panel Modules & Support	$11,000,000	$15,000,000	$19,000,000
500 kW Inverters	$3,000,000	$3,000,000	$3,000,000
Electrical Distribution System	$5,000,000	$5,000,000	$5,000,000
Electrical Interconnect	$500,000	$500,000	$500,000
Engineering, Permitting, Geotech	$2,500,000	$2,500,000	$2,500,000
EPC Cost	**$25,000,000**	**$29,000,000**	**$33,000,000**
Owner Cost			
Project Development	$650,000	$650,000	$650,000
Electrical Interconnect	$450,000	$450,000	$450,000
Construction Power	$50,000	$50,000	$50,000
Owners Project Management	$500,000	$500,000	$500,000
Owners Engineer	$170,000	$170,000	$170,000
Owners Legal Counsel	$250,000	$250,000	$250,000
Land	$500,000	$500,000	$500,000
Electric Transmission Service	$50,000	$50,000	$50,000
Site Security	$50,000	$50,000	$50,000
Spare Parts	$100,000	$100,000	$100,000
AFUDC (KU Ownership Portion)	$150,000	$150,000	$150,000
Contingency (15% of EPC)	$3,750,000	$4,350,000	$4,950,000
Owner Cost	**$6,670,000**	**$7, 270,000**	**$7,870,000**
Total Project Cost	**$31,670,000**	**$36,270,000**	**$40,870,000**
Total Cost $/kW (AC)	**$4872/kW**	**$3627/kW**	**$4087/kW**
Levelized Cost ($/MWHR)	**$226.57**	**$177.08**	**$189.38**

Notes:

1. **EPC Site Preparation cost based on conceptual level design utilizing available USGS topographic survey and boring logs resulting in an estimate accuracy level of -$1,500,000/+$5,000,000. Final design to be based on one (1) foot contour field topographic survey and geotechnical investigation.**

The results of the evaluation indicate the standard efficiency multicrystalline technology is the most economically attractive alternative providing the lowest cost of generation.

2.0 SITE

2.1 BACKGROUND AND DESIGN CRITERIA

The proposed project site is the former Thurman Hardin Estate, a 152 acre parcel currently owned by LG&E-KU located adjacent to the E. W. Brown Station. The parcel consists primarily of rolling open field with several structures constructed.

2.1.1 Basic Structural Design Criteria

The building code to be used for the project is the International Building Code (IBC) 2006.

Snow Loads

Snow design shall be in accordance with IBC 2006, section 1608, utilizing the inputs below:

- Minimum ground snow load = 15 lb/ft2

Wind loads

Wind design shall be in accordance with IBC 2006, section 1609, utilizing the inputs below:

- 3 second gust = 90 miles/hr
- Exposure category = B

Seismic Loads

Seismic design shall be in accordance with IBC 2006, section 1613, utilizing the inputs below:

- Occupancy category = III
- Site (soil) class = D
- Seismic design category = C or D, contractor to verify exact location and category with building official

Frost Penetration

All foundations shall have a minimum depth of 30 inches.

2.1.2 Precipitation

Point precipitation frequency estimates from NOAA Atlas 14 for Louisville, Kentucky:

- Annual average, inches 44.54
- 10 year, 24-hour, inches 6.9
- 25 year, 24-hour, inches 7.86
- 100 year, 24-hour, inches 9.34

2.1.3 Storm Water

Design the storm collection system for a 24 hour, 25 year point precipitation frequency.

3.0 ELECTRICAL INTERCONNECTION

The 10 MW AC solar plant output will be interconnected at 13.8 kV to the LG&E-KU E. W. Brown 13.2 kV auxiliary power system CCRT switchgear bus currently in development. The interconnection will consist of an approximately one mile long wood pole based 13.8 kV overhead line routed on LG&E-KU property. Each line end will include an underground riser to interface to the associated switchgear underground by insulated cable. All metering and protection required to interconnect to the electrical system will be provided,

For the specific electric power system configurations refer to One Line Diagrams 221566-CMP-E1001 and -221566-CMP-E1002 located in Appendix D.

4.0 SOLAR PHOTOVOLTAIC TECHNOLOGY EVALUATION

In general, two types of PV modules are available for consideration: mono/multi crystalline and thin film. There are tradeoffs associated with the different types of panels, such as higher capital costs for mono/multi crystalline panels with greater efficiency versus lower cost and lower efficiency for thin film panels.

PV systems are installed in a fixed position or are equipped with one or two-dimensional tracking systems which enable the panel to remain at a more optimized orientation with respect to the sun across the course of a day and/or season. Tracking systems add significant capital costs, demand more real estate than for fixed systems, and add more annual maintenance costs, but can produce additional generation depending on weather conditions, shading, and other factors.

Typically the quantity of land available and the cost to purchase the land influence the technology selected. High land costs or limited land availability tend to favor higher efficiency, higher cost panels as compared to projects with low land costs and adequate land area available tend to favor lower efficiency, lower cost panels. Tracking systems require a site with minimal grade fluctuations.

Initial photovoltaic (PV) solar technology options considered potentially viable for implementation of a 10 MW AC PV solar facility located at the E.W. Brown Generating Station include:

- Fixed Tilt Thin Film Technology
- Fixed Tilt Multicrystalline Standard Efficiency Technology (300 W panel)
- Fixed Tilt Multicrystalline High Efficiency Technology (315+ W panel)
- Single Axis Tracking Thin Film Technology
- Single Axis Multicrystalline Standard Efficiency Technology (300 Watt panel)
- Single Axis Multicrystalline High Efficiency Technology (320+ Watt panel)

An initial screening determined the E. W. Brown site topography slopes are not practical to construct single axis tracking systems. The site east/west slopes of 5% to 20% far exceed east/west maximum slope requirements of 2%. The analysis is based on fixed tilt systems employing thin film, standard efficiency multicrystalline and high efficiency multicrystalline module technology. A contour type mounting system is required to support an installation on the site terrain with a reasonable degree of site work. The maximum east/west slope criteria established for placement of the three module technologies is 12%.

The screening also concluded the site topography can support the targeted 10 MW AC capacity utilizing standard efficiency and high efficiency multicrystalline modules. The nominal 50 acres of site suitable for solar module installation can support only 6.5 MW AC of thin film solar PV due to the low power density of the technology.

A site arrangement for the standard efficiency multicrystalline based system is included within Appendix A. The nominal 50 acres required for the 10 MW AC standard efficiency multicrystalline layout serves as the basis for the plant footprint as it represents the extent of the available property suitable for solar development considering grade. This footprint can support a 6.5 MW thin film design and is approximately 5% to 10% larger than required for a high efficiency multicrystalline design.

4.1 SOLAR PV PERFORMANCE

HDR modeled the generation of the three technologies applied in a fixed tilt configuration for the proposed site using PVSYST solar modeling software, which is a widely utilized industry generation estimation tool. PVSYST applies hourly historic meteorological data that has been collected to estimate the production of a PV system, based on specific OEM module performance at site conditions.

The following PV system specifications were also utilized in the PVSYST evaluation of the site location for each of the three panel types:

- AC Rating: 10,000 kW (Thin Film analysis based on 6.5 MW due to site size limits)
- DC to AC Conversion Efficiency Factor: 0.80
- Array Tilt: 25 degrees
- Array Azimuth: 0 degrees

Energy produced from the solar array will vary on a monthly basis. The results of the PVSYST analysis for each of the three panels evaluated are included in Appendix C. A summary of the electrical production for each configuration is provided below in Table 2.

Table 2
PVSYST Model Annual Energy Production

Description	Thin Film (6.5 MW AC)	Standard Efficiency	High Efficiency
Panel Manufacturer	First Solar	JA Solar	SunPower
Panel Model	FS-390	JAP6-72-300	SPR.E19.320
Panel Capacity (Watt DC)	90	300	320
Nominal Efficiency	12.54%	15.57%	19.32%
Panel Quantity	86,660	39,995	37,505
Plant Output (kW DC)	7799	11,999	12,002
Plant Output (MW AC)	6.5	10	10
Annual Production (MWHR)	**10,428**	**15,216**	**15,979**

The PVSYST predicted annual electrical energy production supports the revenue portion of the economic analysis.

4.2 SOLAR PV PROJECT CAPITAL COST & SCHEDULE

Equipment pricing for major equipment, including the PV panels, inverters, transformers and switchgear, as well as recent equipment estimates from similar projects were utilized in developing the total project cost. Assumptions and project scope included in the estimate is summarized as follows:

- Packaged 500 kW inverters serving 13.8 kV underground direct buried electric distribution collector system
- Sales tax is included for non-production material
- No permanent office facilities or warehouse space is provided

The following Owner’s costs have also been established and are included in the estimate.

- Project Development
- Interconnection at 13.2 kV to E. W. Brown CCRT 13.8 kV switchgear
- Construction Power (Service Installation and Energy)
- Owner’s Project Management
- Owner’s Engineer
- Owner’s Legal Counsel
- Land Cost
- Site Security

- Operating Spare Parts
- AFUDC for KU Ownership Portion

An Owner's contingency of 15 percent of the total EPC project cost has been included within the project estimate.

The capital cost estimate developed for each of the three panel technologies evaluated is included in Appendix E.

A summary of the estimated plant EPC costs and Owner's costs are depicted in Table 3.

Table 3
Capital Cost Summary

Description	Thin Film (6.5 MW AC)	Standard Efficiency	High Efficiency
EPC Direct Cost			
Site Preparation	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**
Panel Modules & Support	$11,000,000	$15,000,000	$19,000,000
500 kW Inverters	$3,000,000	$3,000,000	$3,000,000
Electrical Distribution System	$5,000,000	$5,000,000	$5,000,000
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EPC Cost	**$25,000,000**	**$29,000,000**	**$33,000,000**
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Project Development	$650,000	$650,000	$650,000
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Owners Project Management	$500,000	$500,000	$500,000
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Land	$500,000	$500,000	$500,000
Electric Transmission Service	$50,000	$50,000	$50,000
Site Security	$50,000	$50,000	$50,000
Spare Parts	$100,000	$100,000	$100,000
AFUDC (KU Ownership Portion)	$150,000	$150,000	$150,000
Contingency (15% of EPC)	$3,750,000	$4,350,000	$4,950,000
Owner Cost	**$6,670,000**	**$7, 270,000**	**$7,870,000**
Total Project Cost	**$31,670,000**	**$36,270,000**	**$40,870,000**
Total Cost $/kW (AC)	**$4872/kW**	**$3627/kW**	**$4087/kW**

Notes:
1. **EPC Site Preparation cost based on conceptual level design utilizing available USGS topographic survey and boring logs resulting in an estimate accuracy level of -$1,500,000/+$5,000,000. Final design to be based on one (1) foot contour field topographic survey and geotechnical investigation.**

The solar PV facility's project schedule from full notice to proceed [FNTP] to commercial operation date has been estimated to be 18 months. This duration includes construction of the 13.8 kV interconnection to the E. W. Brown CCRT switchgear. A December 2016 commercial operation date is planned for the project, with site mobilization in the late summer of 2015.

4.3 SOLAR PV COST OF GENERATION

A life cycle cost analysis was generated for each of the three options under consideration.

The economic assumptions utilized in the analysis are summarized in Table 4.

Table 4 Economic Assumptions

Common Proforma Parameters	
Discount Rate	6.75%
Depreciation Schedule - Tax	20 Year MACRS
Depreciation Schedule - Book	30 Year SL
Amortization	30 Years
Project Life	30 Years
Capital Escalation	2.40%
Income Tax Rate	38.90%
IRR	6.75%
Debt	45.7%
Interest Rate	3.73%

The analysis is based on the following plant performance and operating inputs:

- Plant production as determined by PVSYST
- 1 percent plant degradation applied per year
- O&M is estimated to be $0.006 per kWh (2013$)
- The 30 percent investment tax credit was not included as these are currently set to expire in 2016. The investment tax credit has a substantial impact on the cost of generation for a PV plant. A 10 percent investment tax credit is included, as this is what the tax code will revert back to after 2016 if the credit is not extended. The full amount of the tax credit is applied in the first year of the project.
- A 5-year Modified Accelerated Cost-Recovery Depreciation (MACRS) schedule was applied based on current tax.

The electrical calculated cost of generation for each PV solar plant is summarized below in Table 5. The cost of generation is primarily a function of project capital costs.

Table 5
Cost of Generation Summary

Description	**Thin Film (6.5 MW AC)**	**Standard Efficiency**	**High Efficiency**
Levelized Cost ($/MWHR)	**$226.57**	**$177.08**	**$189.38**

The detailed life cycle cost analysis results are included in Appendix F.

4.4 SOLAR PV TECHNOLOGY SELECTION

The economic analysis concludes the standard efficiency multicrystalline based design provides the lowest life cycle costs. This technology is recommended for application at the E. W. Brown site primarily due to available footprint limitations due to site topography. Panel technology and cost generally change quickly in comparison to traditional power plant equipment, and application of higher efficiency panels may become comparable in cost to the current 300 Watt panel recommended at this time.

5.0 ENVIRONMENTAL REVIEW

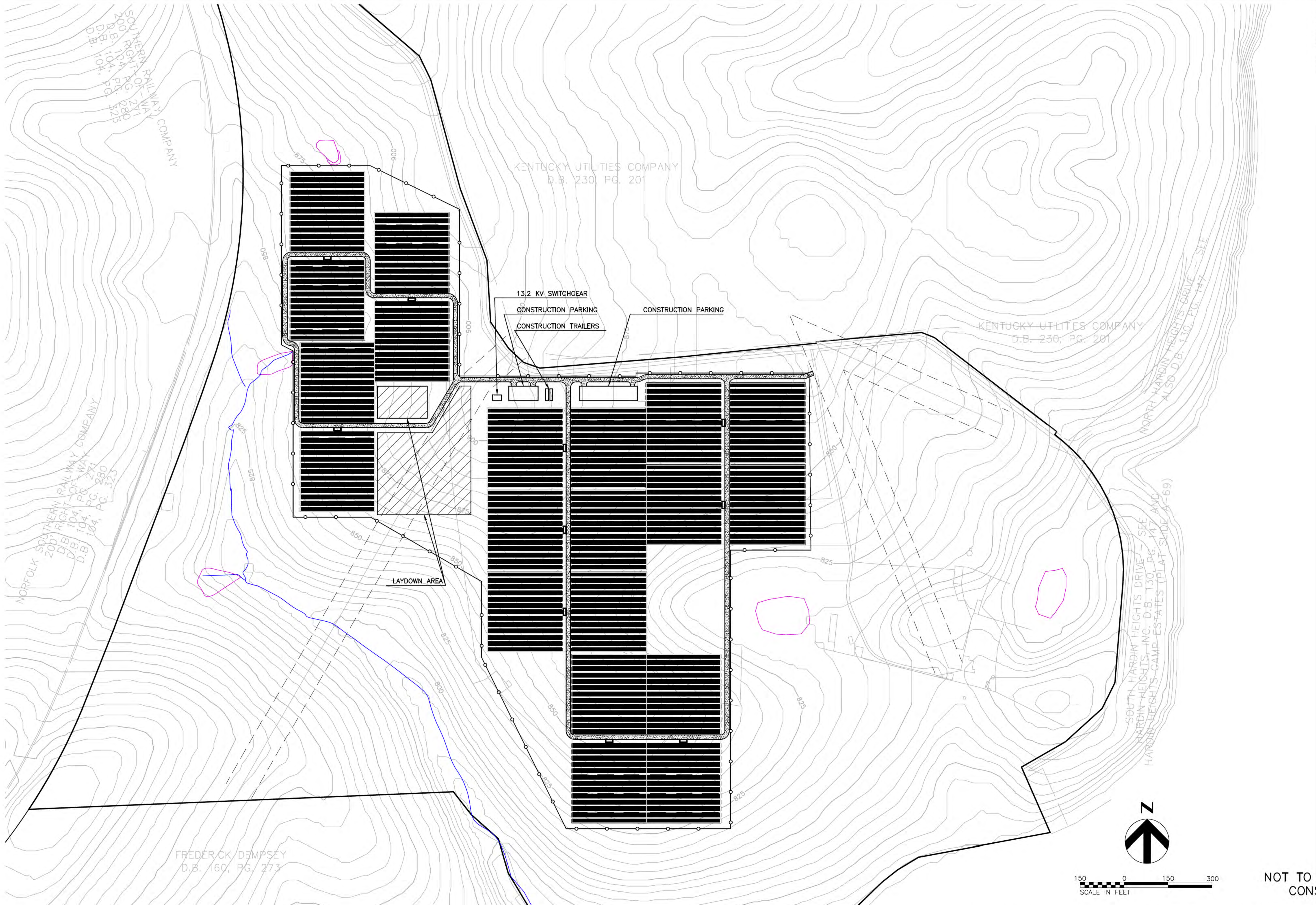
A high level environmental review of the recommended configuration was completed to identify potential project development constraints and is included in Appendix G.

APPENDICES

APPENDIX A

SITE ARRANGEMENT

- 221566-CGA-S1001(B) EW Brown Solar PV Project
  Site Arrangement – Standard Efficiency Crystalline



Revisions

A	05 DEC 2013 INITIAL ISSUE
B	31 JAN 2014 REVISED LAYDOWN AREA

NOT TO BE USED FOR CONSTRUCTION

FIXED-AXIS RACK	
TILT ANGLE	25°
GCR	0.60
AREA	49.7 ACRES
RACK (RBI)	TWO MODULES WIDTH IN PORTRAIT ORIENTATION

Location and Unit:

Scale: 1" = 150' | Contract No.: n/a

Engineering discipline: CIVIL | Drawing type:

LG&E® Generation Services
LOUISVILLE GAS & ELECTRIC COMPANY

Drawn: AMG 12 DEC 13
Checked:
Approved:
Released for: –
Alternate Drawing No: CGA-S1001

Title
EW BROWN STATION SOLAR PV PROJECT
SITE ARRANGEMENT – STANDARD EFFICIENCY
CRYSTALLINE

Originator: HDR ENGINEERING | Job or Project No: 221566 | Drawing No: 221566-CGA-S1001 | Rev.

DMS Version 2.0

APPENDIX B

PROPOSED CONTOUR TYPE MOUNTING SYSTEM

RBI SOLAR

Solar Mounting Systems

CONTOURED SYSTEMS GROUND MOUNT

ENGINEERING MANUFACTURING INSTALLATION

Ground Mount

Roof Mount

Landfill

Specialty Structures


ROW 20

APPENDIX C

SOLAR ARRAY PERFORMANCE PVSYST REPORTS

- Thin Film Technology 90 Watt Panel Technology PVSYST Report
- Multicrystalline Standard Efficiency Technology 300 Watt Panel Technology PVSYST Report
- Multicrystalline High Efficiency Technology 315 Watt Panel Technology PVSYST Report

Grid-Connected System: Simulation parameters

Project : **LGE Solar**

Geographical Site	**Lexington**		Country	**United States**
Situation	Latitude	38.0°N	Longitude	84.6°W
Time defined as	Legal Time	Time zone UT-5	Altitude	295 m
	Albedo	0.20		
Meteo data:	**Lexington**	Synthetic - Meteonorm 6.1		

Simulation variant : **LGE Unlimirted Sheds (90W)**

Simulation date 11/12/13 16h14

Simulation parameters

Collector Plane Orientation	Tilt	25°	Azimuth	0°
260 Sheds	Pitch	5.95 m	Collector width	3.94 m
Inactive band	Top	0.00 m	Bottom	0.00 m
Shading limit angle	Gamma	34.99 °	Occupation Ratio	66.2 %
Models used	Transposition	Perez	Diffuse	Measured
Horizon	Free Horizon			
Near Shadings	Mutual shadings of sheds			

PV Array Characteristics

PV module	CdTe Model	**FS-390**		
	Manufacturer	First Solar		
Number of PV modules	In series	14 modules	In parallel	6190 strings
Total number of PV modules	Nb. modules	86660	Unit Nom. Power	90 Wp
Array global power	Nominal (STC)	**7799 kWp**	At operating cond.	7356 kWp (50°C)
Array operating characteristics (50°C)	U mpp	635 V	I mpp	11579 A
Total area	Module area	**62395 m²**	Cell area	50980 m²
Inverter	Model	**Solar Ware 500 - PVL-L0500E**		
	Manufacturer	TMEIC		
Characteristics	Operating Voltage	450-950 V	Unit Nom. Power	500 kW AC
Inverter pack	Number of Inverter	13 units	Total Power	6500 kW AC

PV Array loss factors

Array Soiling Losses			Loss Fraction	3.0 %
Thermal Loss factor	Uc (const)	29.0 W/m²K	Uv (wind)	0.0 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	0.84 mOhm	Loss Fraction	1.4 % at STC
Module Quality Loss			Loss Fraction	0.0 %
Module Mismatch Losses			Loss Fraction	2.0 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Param.	0.05

System loss factors

External transformer	Iron loss (24H connexion)	7628 W	Loss Fraction	0.0 % at STC
	Resistive/Inductive losses	0.1 mOhm	Loss Fraction	1.0 % at STC

User's needs : Unlimited load (grid)

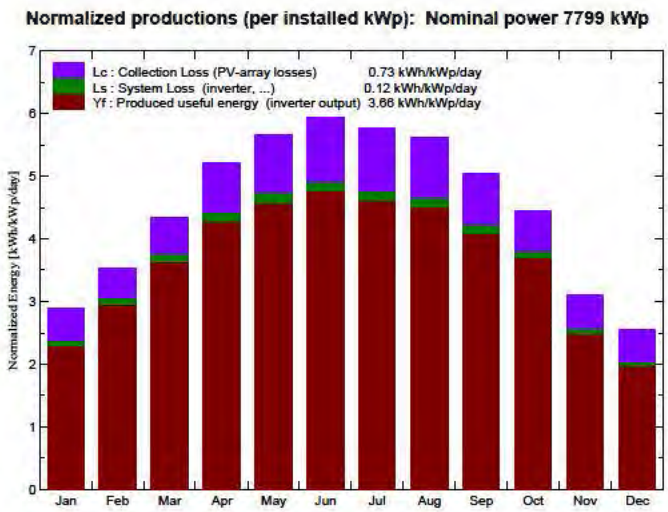
Grid-Connected System: Main results

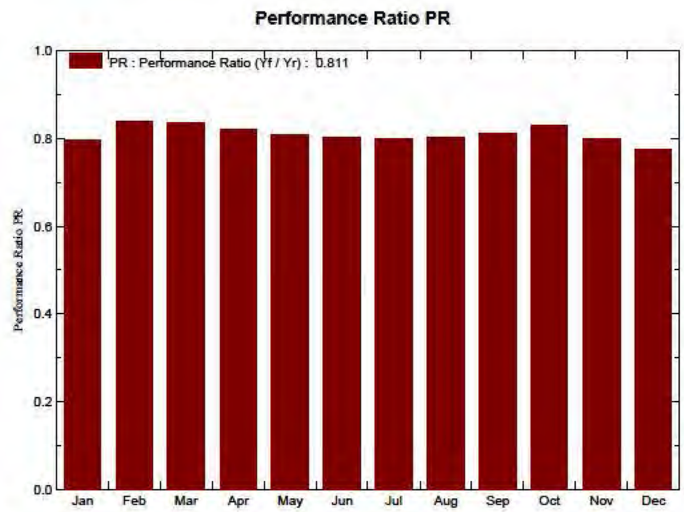
Project : **LGE Solar**

Simulation variant : **LGE Unlimirted Sheds (90W)**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	FS-390	Pnom	90 Wp
PV Array	Nb. of modules	86660	Pnom total	**7799 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	13.0	Pnom total	**6500 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**10428 MWh/year**	Specific prod.	1337 kWh/kWp/year
	Performance Ratio PR	81.1 %		





LGE Unlimirted Sheds (90W)

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	62.5	0.90	89.5	75.1	576	556	10.33	9.96
February	76.6	3.50	98.8	88.6	670	647	10.87	10.50
March	116.1	6.70	134.9	121.7	911	881	10.82	10.47
April	146.9	12.80	156.7	141.6	1035	1002	10.59	10.25
May	177.1	18.10	175.8	158.4	1145	1109	10.44	10.11
June	185.8	22.20	178.4	160.4	1153	1117	10.36	10.04
July	184.5	24.20	178.6	160.8	1151	1115	10.32	10.00
August	168.9	23.60	174.4	157.8	1127	1091	10.36	10.03
September	133.2	20.20	151.2	136.9	989	957	10.48	10.14
October	106.4	14.00	138.1	125.6	923	893	10.71	10.36
November	66.2	8.00	93.3	80.3	603	582	10.36	10.00
December	53.6	2.30	78.9	64.7	495	477	10.06	9.69
Year	1477.7	13.09	1648.6	1472.0	10780	10428	10.48	10.14

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

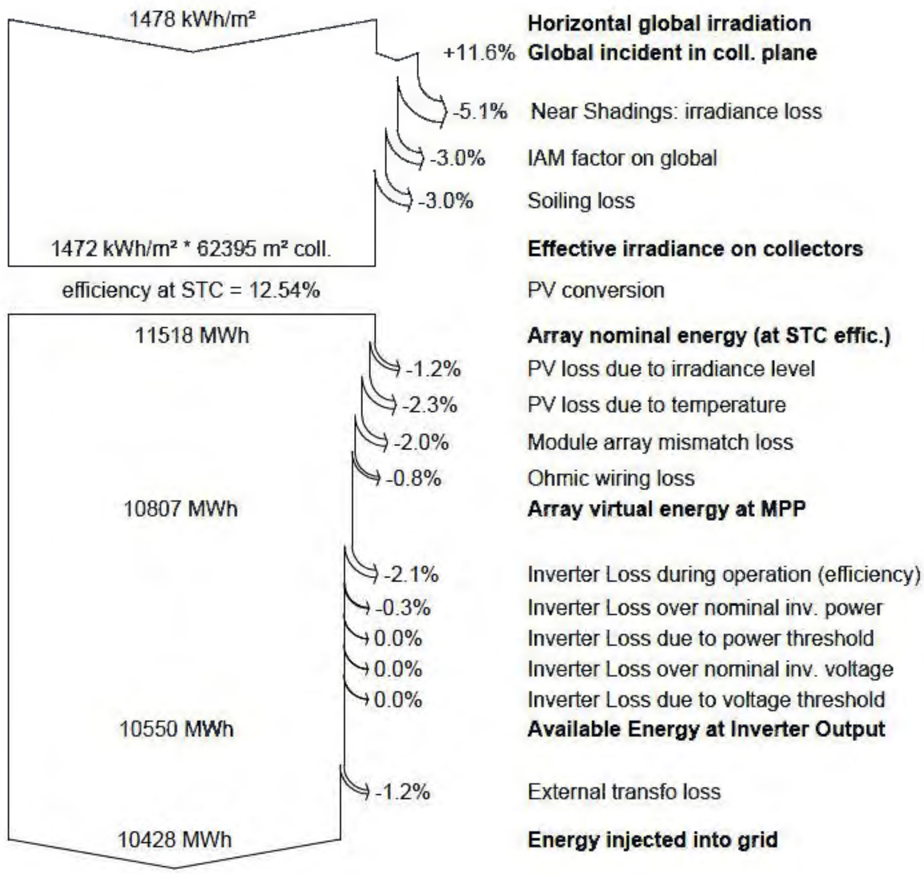
Grid-Connected System: Loss diagram

Project : **LGE Solar**

Simulation variant : **LGE Unlimirted Sheds (90W)**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	FS-390	Pnom	90 Wp
PV Array	Nb. of modules	86660	Pnom total	**7799 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	13.0	Pnom total	**6500 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **LGE Solar**

Geographical Site	**Lexington**		Country	**United States**
Situation	Latitude	38.0°N	Longitude	84.6°W
Time defined as	Legal Time	Time zone UT-5	Altitude	295 m
	Albedo	0.20		
Meteo data:	**Lexington**	Synthetic - Meteonorm 6.1		

Simulation variant : **LGE Solar Unlimited Sheds (300W)**

Simulation date 12/12/13 15h22

Simulation parameters

Collector Plane Orientation	Tilt	25°	Azimuth	0°
260 Sheds	Pitch	5.95 m	Collector width	3.94 m
Inactive band	Top	0.00 m	Bottom	0.00 m
Shading limit angle	Gamma	34.99 °	Occupation Ratio	66.2 %
Models used	Transposition	Perez	Diffuse	Measured
Horizon	Free Horizon			
Near Shadings	Mutual shadings of sheds			

PV Array Characteristics

PV module Si-poly	Model	**JAP6-72-300**		
	Manufacturer	JA Solar		
Number of PV modules	In series	19 modules	In parallel	2105 strings
Total number of PV modules	Nb. modules	39995	Unit Nom. Power	300 Wp
Array global power	Nominal (STC)	**11999 kWp**	At operating cond.	10609 kWp (50°C)
Array operating characteristics (50°C)	U mpp	618 V	I mpp	17172 A
Total area	Module area	**77526 m²**	Cell area	70079 m²
Inverter	Model	**Solar Ware 500 - PVL-L0500E**		
	Manufacturer	TMEIC		
Characteristics	Operating Voltage	450-950 V	Unit Nom. Power	500 kW AC
Inverter pack	Number of Inverter	20 units	Total Power	10000 kW AC

PV Array loss factors

Array Soiling Losses			Loss Fraction	3.0 %
Thermal Loss factor	Uc (const)	29.0 W/m²K	Uv (wind)	0.0 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	0.84 mOhm	Loss Fraction	2.1 % at STC
LID - Light Induced Degradation			Loss Fraction	2.5 %
Module Quality Loss			Loss Fraction	0.0 %
Module Mismatch Losses			Loss Fraction	2.0 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Param.	0.05

Grid-Connected System: Simulation parameters (continued)

System loss factors

External transformer	Iron loss (24H connexion)	11693 W	Loss Fraction	0.0 % at STC
	Resistive/Inductive losses	0.0 mOhm	Loss Fraction	1.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Main results

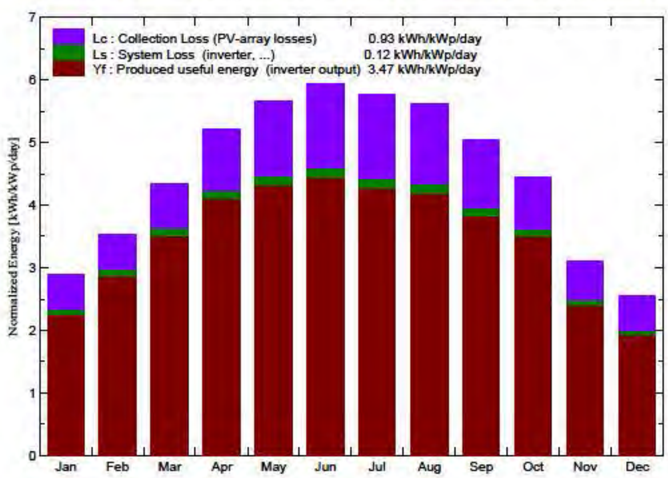
Project : **LGE Solar**

Simulation variant : **LGE Solar Unlimited Sheds (300W)**

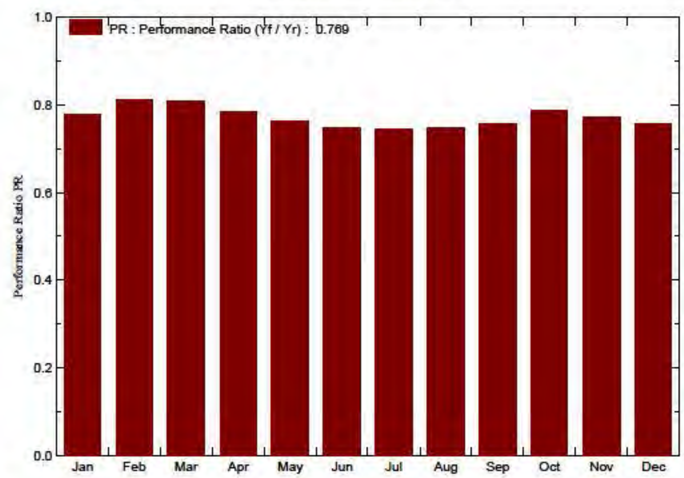
Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	JAP6-72-300	Pnom	300 Wp
PV Array	Nb. of modules	39995	Pnom total	**11999 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	20.0	Pnom total	**10000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**15215678 kWh/year**	Specific prod.	1268 kWh/kWp/year
	Performance Ratio PR	76.9 %		

Normalized productions (per installed kWp): Nominal power 11999 kWp



Performance Ratio PR



LGE Solar Unlimited Sheds (300W)

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_Grid kWh	EffArrR %	EffSysR %
January	62.5	0.90	89.5	75.1	868068	836917	12.52	12.07
February	76.6	3.50	98.8	88.6	997998	963823	13.03	12.58
March	116.1	6.70	134.9	121.7	1354542	1309646	12.95	12.52
April	146.9	12.80	156.7	141.6	1524315	1475281	12.55	12.15
May	177.1	18.10	175.8	158.4	1659549	1607685	12.18	11.80
June	185.8	22.20	178.4	160.4	1652844	1601414	11.95	11.58
July	184.5	24.20	178.6	160.8	1646903	1596074	11.89	11.53
August	168.9	23.60	174.4	157.8	1613162	1562687	11.93	11.56
September	133.2	20.20	151.2	136.9	1422035	1376949	12.13	11.74
October	106.4	14.00	138.1	125.6	1347124	1303294	12.58	12.17
November	66.2	8.00	93.3	80.3	895308	864265	12.38	11.95
December	53.6	2.30	78.9	64.7	745545	717643	12.18	11.73
Year	1477.7	13.09	1648.6	1472.0	15727394	15215678	12.31	11.91

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

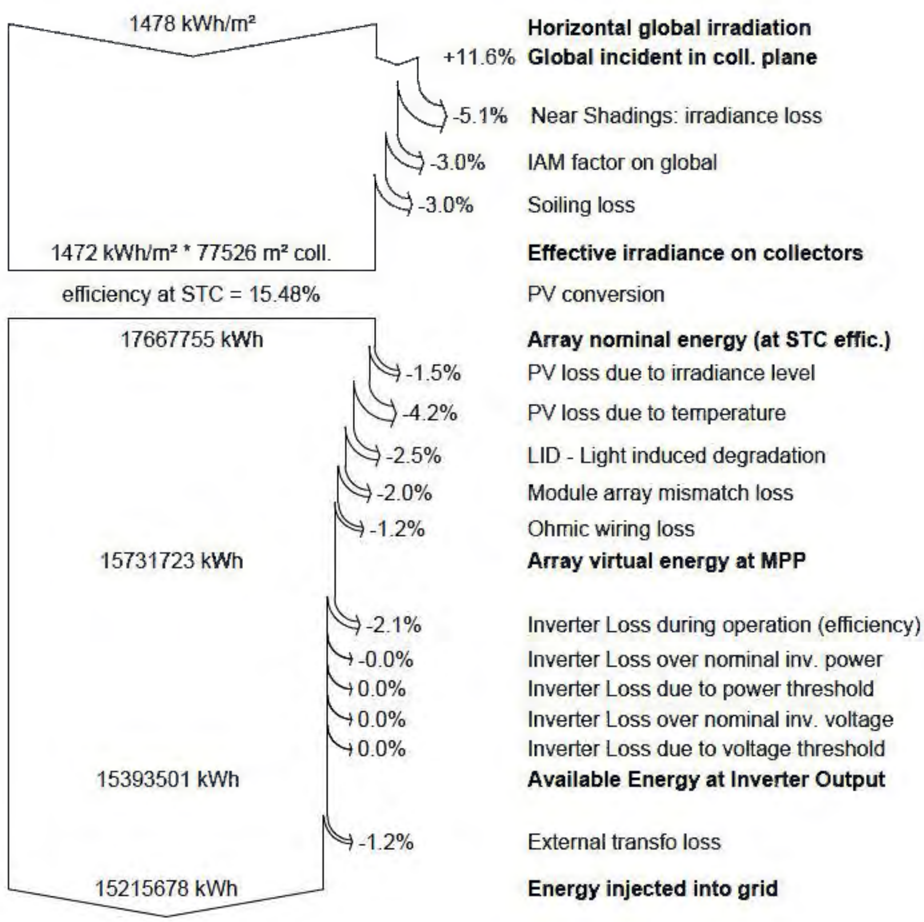
Grid-Connected System: Loss diagram

Project : **LGE Solar**

Simulation variant : **LGE Solar Unlimited Sheds (300W)**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	JAP6-72-300	Pnom	300 Wp
PV Array	Nb. of modules	39995	Pnom total	**11999 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	20.0	Pnom total	**10000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **LGE Solar**

Geographical Site	**Lexington**		Country	**United States**
Situation	Latitude	38.0°N	Longitude	84.6°W
Time defined as	Legal Time	Time zone UT-5	Altitude	295 m
	Albedo	0.20		
Meteo data:	**Lexington**	Synthetic - Meteonorm 6.1		

Simulation variant : **LGE Unlimirted Sheds (315W)**

Simulation date 12/12/13 15h19

Simulation parameters

Collector Plane Orientation	Tilt	25°	Azimuth	0°
250 Sheds	Pitch	5.95 m	Collector width	3.94 m
Inactive band	Top	0.00 m	Bottom	0.00 m
Shading limit angle	Gamma	34.99 °	Occupation Ratio	66.2 %
Models used	Transposition	Perez	Diffuse	Measured
Horizon	Free Horizon			
Near Shadings	Mutual shadings of sheds			

PV Array Characteristics

PV module Si-mono	Model	**SPR-E19-320**		
	Manufacturer	SunPower		
Number of PV modules	In series	13 modules	In parallel	2885 strings
Total number of PV modules	Nb. modules	37505	Unit Nom. Power	320 Wp
Array global power	Nominal (STC)	**12002 kWp**	At operating cond.	10855 kWp (50°C)
Array operating characteristics (50°C)	U mpp	631 V	I mpp	17196 A
Total area	Module area	**61160 m²**	Cell area	55195 m²
Inverter	Model	**Solar Ware 500 - PVL-L0500E**		
	Manufacturer	TMEIC		
Characteristics	Operating Voltage	450-950 V	Unit Nom. Power	500 kW AC
Inverter pack	Number of Inverter	20 units	Total Power	10000 kW AC

PV Array loss factors

Array Soiling Losses			Loss Fraction	3.0 %
Thermal Loss factor	Uc (const)	29.0 W/m²K	Uv (wind)	0.0 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	0.84 mOhm	Loss Fraction	2.0 % at STC
LID - Light Induced Degradation			Loss Fraction	2.5 %
Module Quality Loss			Loss Fraction	0.0 %
Module Mismatch Losses			Loss Fraction	2.0 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Param.	0.05

Grid-Connected System: Simulation parameters (continued)

System loss factors

External transformer	Iron loss (24H connexion)	11722 W	Loss Fraction	0.0 % at STC
	Resistive/Inductive losses	0.0 mOhm	Loss Fraction	1.0 % at STC

User's needs : Unlimited load (grid)

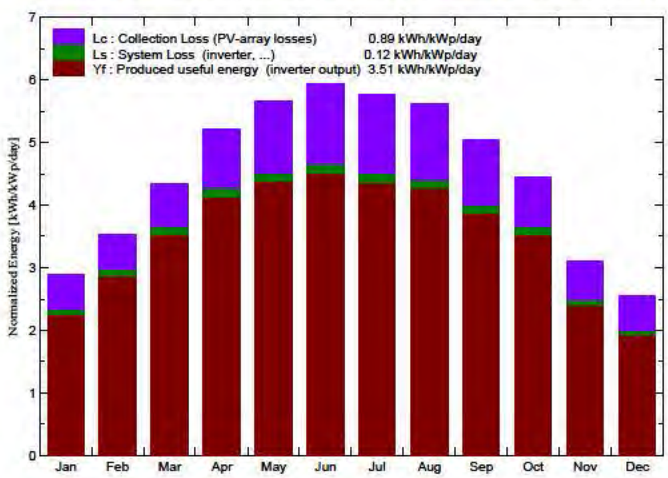
Grid-Connected System: Main results

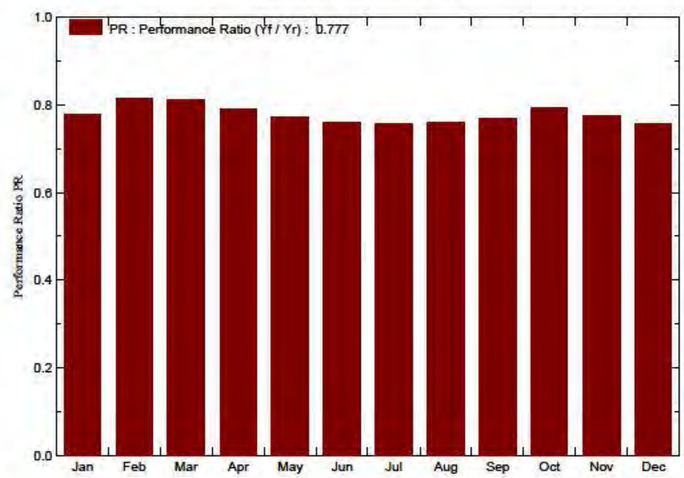
Project : **LGE Solar**

Simulation variant : **LGE Unlimirted Sheds (315W)**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	SPR-E19-320	Pnom	320 Wp
PV Array	Nb. of modules	37505	Pnom total	**12002 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	20.0	Pnom total	**10000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**15372 MWh/year**	Specific prod.	1281 kWh/kWp/year
	Performance Ratio PR	77.7 %		





LGE Unlimirted Sheds (315W)

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	62.5	0.90	89.5	75.1	867	836	15.84	15.27
February	76.6	3.50	98.8	88.6	1001	966	16.56	15.99
March	116.1	6.70	134.9	121.7	1360	1315	16.48	15.94
April	146.9	12.80	156.7	141.6	1537	1487	16.04	15.52
May	177.1	18.10	175.8	158.4	1682	1629	15.65	15.16
June	185.8	22.20	178.4	160.4	1680	1627	15.40	14.92
July	184.5	24.20	178.6	160.8	1675	1623	15.33	14.85
August	168.9	23.60	174.4	157.8	1642	1590	15.40	14.91
September	133.2	20.20	151.2	136.9	1443	1397	15.60	15.10
October	106.4	14.00	138.1	125.6	1361	1316	16.11	15.58
November	66.2	8.00	93.3	80.3	898	867	15.74	15.20
December	53.6	2.30	78.9	64.7	745	717	15.43	14.85
Year	1477.7	13.09	1648.6	1472.0	15889	15372	15.76	15.25

Legends:				
GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
T Amb	Ambient Temperature	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

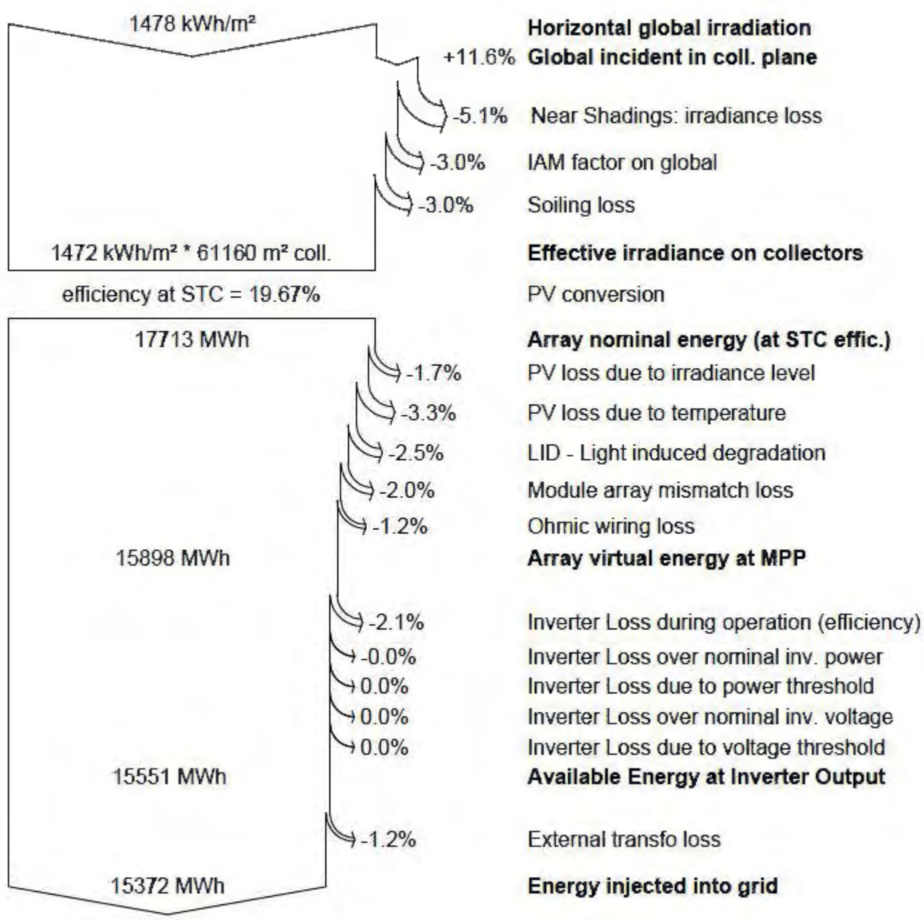
Grid-Connected System: Loss diagram

Project : **LGE Solar**

Simulation variant : **LGE Unlimirted Sheds (315W)**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Sheds disposition, tilt	25°	azimuth	0°
PV modules	Model	SPR-E19-320	Pnom	320 Wp
PV Array	Nb. of modules	37505	Pnom total	**12002 kWp**
Inverter	Model	Solar Ware 500 - PVL-L0500E	Pnom	500 kW ac
Inverter pack	Nb. of units	20.0	Pnom total	**10000 kW ac**
User's needs	Unlimited load (grid)			

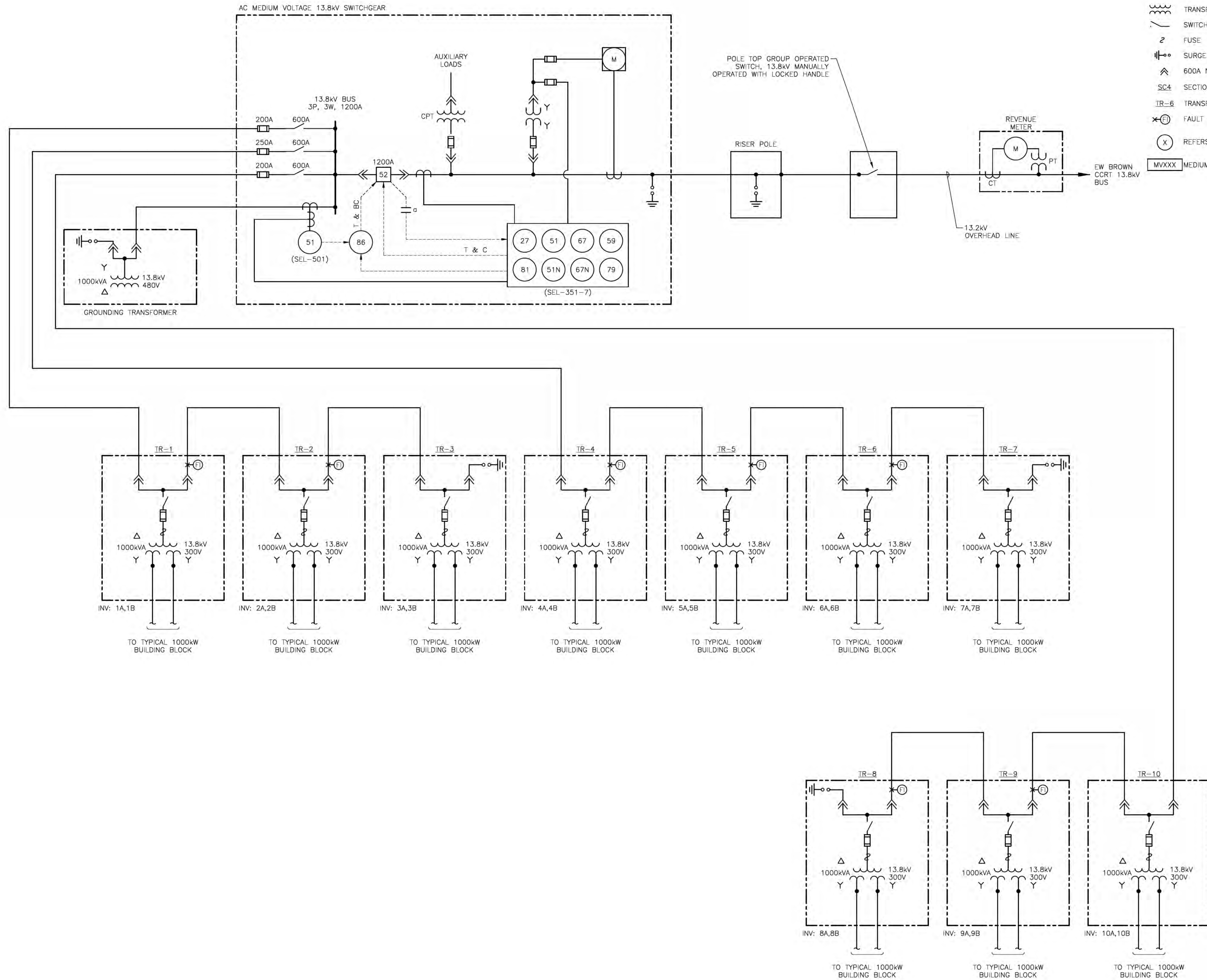
Loss diagram over the whole year



APPENDIX D

ONE LINE DIAGRAMS

- 221566-CMP-E1001(A) EW Brown Solar PV Project
  AC One-Line Diagram
- 221566-CMP-E1002(A) EW Brown Solar PV Project
  DC One-Line Diagram



LEGEND

- TRANSFORMER
- SWITCH
- FUSE
- SURGE ARRESTOR
- 600A NON-LOAD BREAK ELBOW
- SC4 SECTIONALIZED CABINET #
- TR-6 TRANSFORMER #
- FAULT INDICATOR, TEST POINT RESET, SEL OR EQUIVALENT
- (X) REFERS TO CABLE SCHEDULE, THIS DRAWING
- MVXXX MEDIUM VOLTAGE CABLE IDENTIFICATION NUMER

Revisions

A 10 JAN 2014 INITIAL ISSUE

NOT TO BE USED FOR CONSTRUCTION

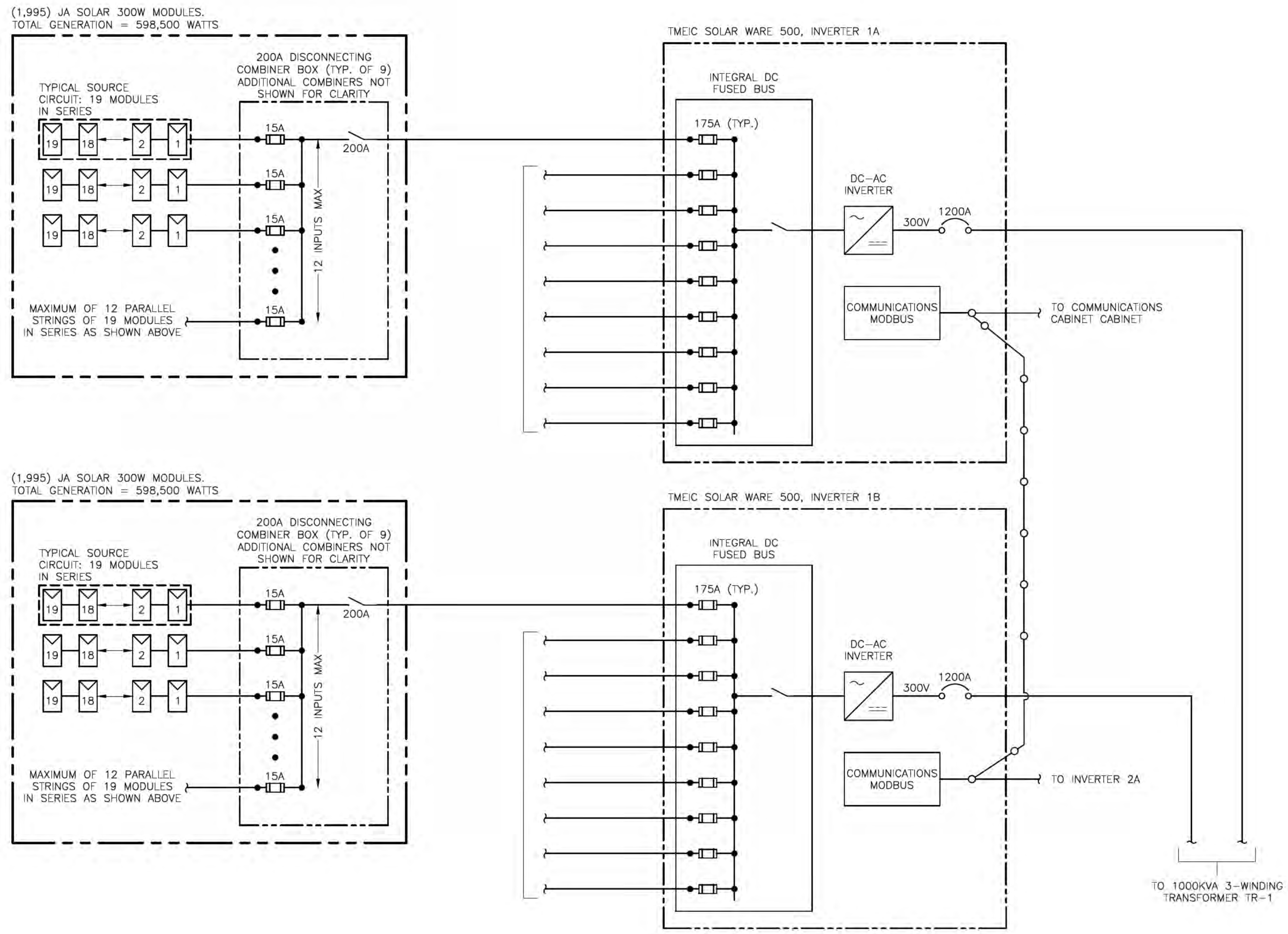
Location and Unit:	LG&E® Generation Services LOUISVILLE GAS & ELECTRIC COMPANY	Drawn: ADK 12/23/13
Scale: n/a; Contract No. n/a		Checked:
Engineering discipline: ELECTRICAL; Drawing type:		Approved:
Title: EW BROWN STATION SOLAR PV PROJECT AC ONE-LINE DIAGRAM		Released for: —
		Alternate Drawing No. CMP-E1001
Originator: HDR ENGINEERING	Job or Project No: 221566	Drawing No: 221566-CMP-E1001; Rev:

EMS Version 2.0

TOTAL SYSTEM DESCRIPTION	
MODULE TYPE	JA SOLAR 300W
QUANTITY	39,900 MODULES
SYSTEM SIZE (DC)	12.0 MW DC
SYSTEM SIZE (AC)	10.0 MW AC
TILT ANGLE	25° FIXED
INVERTER	TMEIC 500kW (20 TOTAL)
TRANSFORMER	1000kVA (10 TOTAL)

Revisions

A 10 JAN 2014 INITIAL ISSUE



NOT TO BE USED FOR CONSTRUCTION

Location and Unit:	LG&E® LOUISVILLE GAS & ELECTRIC COMPANY		Drawn: ADK 12/23/13
Scale: n/a	Contract No. n/a		Checked:
Engineering discipline: ELECTRICAL	Drawing type:		Approved:
Title: EW BROWN STATION SOLAR PV PROJECT DC ONE-LINE DIAGRAM			Released for: –
			Alternate Drawing No: CMP-E1002
Originator: HDR ENGINEERING	Job or Project No: 221566	Drawing No: 221566-CMP-E1002	Rev.

DMS Version 2.0

APPENDIX E

PROJECT COST ESTIMATES

- 6.5 MW PV Solar Thin Film Panel Project Cost Estimate
- 10 MW PV Solar Standard Efficiency Crystalline Panel Project Cost Estimate
- 10 MW PV Solar High Efficiency Crystalline Panel Project Cost Estimate

6.5 MW PV Solar - Thin Film Panels
E. W. Brown Station Site

BUDGET ESTIMATE

5 x 10 Work Week

February 11, 2014

Rev 0

CONFIDENTIAL

6.5 MW PV Solar - Thin Film Panels

LOCATION: Kentucky
PROJECT # 221566
PLANT TYPE: **Solar PV**
CLIENT: LG&E/KU
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR:

STATUS DATE: 11-Feb-14

COST DATE BASIS: February 2013		TECHNOLOGY: Crystalline Standard Efficiency	
NTP PERIOD:		NET MW RATING: 6.5	BOILER: N/A
CONSTRUCTION NTP - Mob:		NO. OF UNITS: 1	STEAM TURBINE: N/A
COMMERCIAL OPERATION DATE:	1-Dec-2016	FUEL TYPE: Solar	COOLING TYPE: N/A

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Manhours**	**Subcontractor or Other $**	**Project Total $**	**%**
Site Preparation	$0	$831,050	$893,439	19,839	515,750	$2,240,239	9.0%
Panel Modules and Support System	$0	$4,835,628	$0	0	4,000,000	$8,835,628	35.4%
Inverter Systems	$0	$2,400,000	$173,318	2,604	0	$2,573,318	10.3%
Electrical Distribution	$0	$1,844,689	$1,986,226	40,692	0	$3,830,915	15.3%
Interconnection	$0	$200,000	$229,451	4,557	0	$429,451	1.7%
Sub-Total Direct Costs:	$0	$10,111,367	$3,282,434	67,692	$4,515,750	$17,909,551	71.7%
State Sales Tax (Non-Production Material Only)					54,222	$54,222	0.2%
Total Direct Cost	$0	$10,111,367	$3,282,434	67,692	$4,569,972	$17,963,773	71.9%
Construction Indirects & Services							
- Construction Indirects						$2,694,566	10.8%
Sub-Total Construction Indirects and Services		$0	$0	0	$0	$2,694,566	10.8%
Total Construction Cost	$0	$10,111,367	$3,282,434	67,692	$4,569,972	$20,658,339	82.7%
Estimated Subcontract Labor Hours				35,651			
Project Indirects							
- Project Engineering (Eng, PM, CM & Procurement)					$2,009,250	$2,009,250	8.0%
Sub-Total Project Indirects	$0	$0	$0	0	$2,009,250	$2,009,250	8.0%
EPC Contractor Insurance & Misc Costs							
- Builders Risk					$103,292	$103,292	0.4%
- Comprehensive General Liability (CGL) Insurance					$103,292	$103,292	0.4%
- Warranty Reserve					$50,000	$50,000	0.2%
Sub-Total EPC Contractor Insur. & Misc. Costs	$0	$0	$0	0	$256,583	$256,583	1.0%
Total EPC Contractor Project Indirect Cost	$0	$0	$0	0	$2,265,834	$2,265,834	9.1%
Sub-Total	0	10,111,367	3,282,434	103,343	6,835,806	22,924,173	91.7%
- EPC Contractor Contingency, G&A and Fe	$0	$1,011,137	$328,243		$726,454	$2,065,834	8.3%
TOTAL EPC PROJECT COST	$0	$10,111,367	$3,282,434	103,343	$6,835,806	$24,990,007	100.0%
EPC Price per kW						$3,845	
Owner Indirect Costs							
- Total Owner Indirects						$2,920,000	
- Owner Contingency						$3,748,501	
TOTAL PROJECT COST						$31,658,508	
Total Project Cost per kW						$4,871	

Total Craft Labor Hours	103,343	**erformance Guarantees:**		**Executive-in-Charge:**	WHD
Ave. Craft Wage without Escalation	$51.66	**Liquidated Damages:**		**Project Manager:**	JPS
Field Labor Type	TBD	**Special Insurance:**		**Construction Manager:**	SMP
Labor Productivity Factor	1.065	**Performance Bond:**		**Lead Estimator:**	CDF

CONFIDENTIAL

6.5 MW PV Solar - Thin Film Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
Line #																					
1	**Site Preparation**																				
2	Sitework	Roads - Asphalt Paving Entrance/Approach	600	sy	Sub	Contr	20.00		43.18		1.09	0	0	YES	360	0	0	0	12,000	$12,000	HDR|CB Estimated Quantity
3	Sitework	Roads - Site Roads Treated Gravel	20,000.0	sy	Contr	Contr	5.00	0.055	43.18	1,100	1.09	0	100,000	YES	6,000	51,540	1,194	151,540	0	$151,540	HDR|CB Estimated Quantity
4	Sitework	Soil Erosion Control Measures	100 000	lf	Contr	Contr	1	0.027	43.18	2 700	1.09	0	100 000	YES	6 000	126 508	2 700	226 508	0	226 508	HDR|CB Estimated Quantity
5	Sitework	Site - Topsoil stripping/stockpiling	400,000	cy	Contr	Contr		0.030	43.18	12,000	1.09	0	0	YES	0	562,259	12,000	562,259	0	$562,259	HDR|CB Estimated Quantity
6	Sitework	Site - Drainage - Pipe Culverts (Assume 12" dia)	300	lf	Contr	Contr	9.00	0.12	43.18	36	1.09	0	2,700	YES	162	1,687	36	4,387	0	$4,387	HDR|CB Estimated Quantity
9	Sitework	Utility Trench Excavation	2 000	cy	Contr	Contr		0 2	38.31	400	1.09	0	0	YES	0	16 627	400	16 627	0	$16 627	HDR|CB Estimated Quantity
12	Sitework	Spoil Disposal	0	cy	Contr	Contr		0.1	43.18	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
13	Sitework	Site Finishing - Seed Site Earthwork	45.0	ac	Contr	Contr	10 000.00	0.54	38.31	24	1.09	0	450 000	YES	27 000	1 010	26	451 010	0	$451 010	HDR|CB Estimated Quantity
14	Sitework	Site Finishing - Grading around foundations	0.0	sy	Contr	Contr		0.02	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
15	Sitework	Site Finishing - Stone Surfacing	0.0	sy	Contr	Contr	10.00	0.015	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
16	Sitework	Site Improvements - Site Entrance Sign and Landscaping	1.0	ls	Contr	Contr	18 750.00	240	38.31	240	1.09	0	18 750	YES	1 125	9 976	260	28 726	0	$28 726	HDR|CB Estimated Quantity
17	Sitework	Site Improvements - Site Security Boundary Fencing	6,000.0	lf	Contr	Contr	11.00	0 2	38.31	1,200	1.09	0	66,000	YES	3,960	49,880	1,302	115,880	0	$115,880	HDR|CB Estimated Quantity
18	Sitework	Site Surveying	1.0	lot	Sub	Contr	150,000.00	0	43.18	0	1.09	0	0	YES	4,500	0	0	0	150,000	$150,000	HDR|CB Estimated Quantity
19	Sitework	Cut and chip medium trees to 12" dia	5	acre	Sub	Contr	6 600	0	38.31	0	1.09	0	0	NO	0	0	0	0	33 000	$33 000	HDR|CB Estimated Quantity
20	Sitework	Grub stumps & remove	5	acre	Sub	Contr	4,150	0	38.31	0	1.09	0	0	NO	0	0	0	0	20,750	$20,750	HDR|CB Estimated Quantity
21	Sitework	Strip and stockpile loam or topsoil, 6", 500 ft push	30,000	cy	Sub	Contr	10.00	0	38.31	0	1.09	0	0	NO	0	0	0	0	300,000	$300,000	HDR|CB Estimated Quantity
22	Sitework	Equip Fdn - Inverter/Transformer	300	cy	Contr	Contr	260	5	38.51	1,500	1.09	0	78,000	YES	4,680	62,672	1,628	140,672	0	$140,672	HDR|CB Estimated Quantity
23	Sitework	13.8 kV Switchgear Foundation	60.0	cy	Contr	Contr	260	4 5	38.51	270	1.09	0	15 600	NO	0	11 281	293	26 881	0	$26 881	HDR|CB Estimated Quantity
24		**Site Preparation Sub-Total**								**19,470**		**0**	**831,050**		**53,787**	**893,439**	**19,839**	**1,724,489**	**515,750**	**2,240,239**	
25																					
26	**Panel Modules and Support System**																				
27																					
28	Modules	Solar Module (Multicrystalline - 300W)	86 660	ea	Contr	Contr	55.80	0	66.56	0	1.09	0	4 835 628	NO	0	0	0	4 835 628	0	$4 835 628	OEM Budget Proposal
29	Rack	Support and Mounting System (Steel Pile) incl. Module Install	1.0	ea	Sub	Contr	4 000 000	0	66.56	0	1.09	0	0	NO	0	0	0	0	4 000 000	$4 000 000	OEM Budget Proposal
30		**Panel Modules and Support Sub-Total**								**0**		**0**	**4,835,628**		**0**	**0**	**0**	**4,835,628**	**4,000,000**	**8,835,628**	
31																					
32	**Inverter Systems**																				
33																					
34	Inverter	500 kW Packaged Inverter	20.0	ea	Contr	Contr	120 000.00	120	66.56	2 400	1.09	0	2 400 000	NO	0	173 318	2 604	2 573 318	0	$2 573 318	OEM Budget Proposal
35		**Inverter Systems Sub-Total**								**2,400**		**0**	**2,400,000**		**0**	**173,318**	**2,604**	**2,573,318**	**0**	**2,573,318**	
36																					
37	**Electrical Distribution**																				
38																					
39	Electrical	Eqpt - 15 kV Switchgear (1 Main CB 3 Fused Feeders)	1.0	lot	Contr	Contr	400 000.00	635	48.81	635	1.09	0	400 000	NO	0	33 629	689	433 629	0	$433 629	HDR|CB Estimated cost
40	Electrical	Eqpt - Transformer 1 MVA, 13.8kV-300V	10.0	ea	Contr	Contr	80,000.00	210	48.81	2,100	1.09	0	800,000	NO	0	111,215	2,279	911,215	0	$911,215	HDR|CB Estimated cost
41	Electrical	Eqpt - Station Service Load Center 13,800/480 Outdoor	1.0	ea	Contr	Contr	120,000.00	160	48.81	160	1.09	0	120,000	YES	7,200	8,474	174	128,474	0	$128,474	HDR|CB Estimated cost
42	Electrical	Eqpt - Panelboards 480/120	1.0	ea	Contr	Contr	1 200.00	40.00	48.81	40	1.09	0	1 200	YES	72	2 118	43	3 318	0	$3 318	HDR|CB Estimated cost
43	Electrical	Grounding - Buried Ground Conductor	2 400	lf	Contr	Contr	4.79	0.054	48.81	130	1.09	0	11 496	NO	0	6 864	141	18 360	0	$18 360	HDR|CB Estimated Quantity & Cost
44	Electrical	Grounding - Ground Rods Copper	40	ea	Contr	Contr	22.95	1.74	48.81	70	1.09	0	918	NO	0	3,686	76	4,604	0	$4,604	HDR|CB Estimated Quantity & Cost
45	Electrical	Grounding - Exothermic Connections	160	ea	Contr	Contr	9.75	1.14	48.81	182	1.09	0	1,560	NO	0	9,660	198	11,220	0	$11,220	HDR|CB Estimated Quantity & Cost
46	Electrical	Conduit - Embedded/Direct Buried	0	lf	Contr	Contr	8.50	0.30	48.81	0	1.09	0	0	NO	0	0	0	0	0	$0	HDR|CB Estimated Quantity & Cost
47	Electrical	Cable - Medium Voltage (15kV 1C Cable)	50,000	lf	Contr	Contr	19.60	0.200	48.81	10,000	1.09	0	980,000	NO	0	529,597	10,850	1,509,597	0	$1,509,597	HDR|CB Estimated Quantity & Cost
48	Electrical	Cable Terminations - 15kV	60	ea	Contr	Contr	195.00	12.00	48.81	720	1.09	0	11,700	NO	0	38,131	781	49,831	0	$49,831	HDR|CB Estimated Quantity & Cost
49	Electrical	Cable 600V Power 1/C	125 000	lf	Contr	Contr	6.55	0.150	48.81	18 750	1.09	0	818 750	NO	0	992 994	20 344	1 811 744	0	$1 811 744	HDR|CB Estimated Quantity & Cost
50	Electrical	Wire 600V Power 3/c # 10 ave. size	1 000	lf	Contr	Contr	0.27	0.0185	48.81	19	1.09	0	270	NO	0	980	20	1 250	0	$1 250	HDR|CB Estimated Quantity & Cost
51	Electrical	Cable Terminations - low voltage	15 000	ea	Contr	Contr	0.85	0.300	48.81	4 500	1.09	0	12 750	NO	0	238 319	4 883	251 069	0	$251 069	HDR|CB Estimated Quantity & Cost
52	Electrical	Wire - Lighting 1/C No 12	4,800	lf	Contr	Contr	0.176	0.018	48.81	86	1.09	0	845	YES	51	4,576	94	5,421	0	$5,421	HDR|CB Estimated Quantity & Cost
53	Electrical	Lighting - Outdoor Fixtures, pole	4	ea	Contr	Contr	1,600.00	12.00	48.81	48	1.09	0	6,400	YES	384	2,542	52	8,942	0	$8,942	HDR|CB Estimated Quantity & Cost
54	Electrical	Electrical Circuit Testing	1,500	ea	Contr	Contr		2	48.81	3,000	1.09	0	0	NO	0	158,879	3,255	158,879	0	$158,879	HDR|CB Estimated Quantity & Cost
55		**Total Cable**	**176,000.0**	**LF**																	
56		**Electrical Distribution Sub-Total**								**37,505**		**0**	**1,844,689**		**435**	**1,986,226**	**40,692**	**3,830,915**	**0**	**3,830,915**	
57																					
58	**Division #6.2 - Interconnection**																				
59																					
60	HV Electrical	CCRT 13 2 kV Switchgear Modifications (Breaker + Metering)	1.0	lot	Contr	Contr	125 000.00	200.00	57.82	200	1.09	0	125 000	NO	0	12 547	217	137 547		$137 547	HDR|CB Estimated Quantity & Cost
61	HV Electrical	Overhead 13.8 kV Line	1.0	lot	Contr	Contr	75,000.00	3,750.00	49.98	4,000	1.09	0	75,000	NO	0	216,904	4,340	291,904		$291,904	HDR|CB Estimated Quantity & Cost
62		**Interconnection Sub-Total**								**4,200**		**0**	**$200,000**		**0**	**$229,451**	**$4,557**	**$429,451**	**$0**	**$429,451**	
63																					
64			0.0																		
65		**Sub-Total Direct Costs**								**63,575**		**0**	**10,111,367**		**54,222**	**3,282,434**	**67,692**	**13,393,801**	**4,515,750**	**17,909,551**	
66	Indirectsa	Sales Tax - State (Plant Production Equipment is Exempt)	6.00%												**54,222**				**54,222**	**54,222**	Sales Tax Included for Non-Production Facilities
67																					
68		**TOTAL DIRECT COSTS**								**63,575**		**0**	**10,111,367**			**3,282,434**	**67,692**	**13,393,801**	**4,569,972**	**$17,963,773**	
69																					
70	**Division #8.0 - Construction and Indirect Services**																				
71																					
72	Const Indirect	Construction Field Indirects	15%	%	Contr	Contr													2,694,566	$2,694,566	
73																					
74		**Construction Indirects and Services Sub-Total**								**0**		**0**	**0**			**0**	**0**	**0**	**2,694,566**	**$2,694,566**	
75																					
76		**SUB-TOTAL CONSTRUCTION COST**								**63,575**		**0**	**10,111,367**			**3,282,434**	**67,692**	**13,393,801**	**7,264,538**	**20,658,339**	
77																					
78	**Division #9.0 - Project Indirects**																				
79																					
80	Project Indirec	- Power Plant Design Engineering	1.0	ls	Contr	9.0%	1 859 250											0	1 859 250	$1 859 250	% of the Total Construction Cost
81	Project Indirec	- Geotechnical Investigation	1.0	ls	Contr		150,000											0	150,000	$150,000	Included in Engineering Contract
82																					
83																					
84		Sub-Total Project Indirects										**0**	**0**			**0**	**0**	**0**	**2,009,250**	**$2,009,250**	
85																					
86	EPC Indirects	EPC Contractor Insurance & Misc Costs (% of Total Const. Cost)																			
87																					
88	EPC Indirects	- Builders Risk Insurance	1.0	ls	Contr	0.50%	103 292												103 292	$103 292	Allowance based on info from other projects
89	EPC Indirects	- Comprehensive General Liability (CGL) Insurance	1.0	ls	Contr	0.50%	103,292											0	103,292	$103,292	Allowance based on info from other projects
90	EPC Indirects	- Warranty Reserve	1.0	ls	Contr		50,000											0	50,000	$50,000	Allowance based on info from other projects
91																					
92		Sub-Total EPC Contractor Indirects										**0**	**0**			**0**	**0**	**0**	**256,583**	**$256,583**	
93																					
94		**Total Project Indirects**										**0**	**0**			**0**	**0**	**0**	**2,265,834**	**2,265,834**	
95																					
96		Sub-Total										**0**	**10,111,367**			**3,282,434**	**67,692**	**13,393,801**	**9,530,371**	**$22,924,173**	
97							ME	Mat	Labor	S/C											
98	EPC Indirects	EPC Contractor Contingency, G&A and Fee	Varies	%	Contr		10.0%	10.0%	10.0%	10.0%		0	1,011,137			328,243		1,339,380	726,454	2,065,834	
99																					
100		Sub-Total		ls								0	1 011 137			328 243	0	1 339 380	726 454	$2 065 834	
101																					
102		**TOTAL EPC PROJECT COST**								**0**		**0**	**11,122,504**			**3,610,678**	**67,692**	**14,733,181**	**10,256,825**	**24,990,007**	
103																					
104	**OWNER INDIRECTS**																				
105	**Owner Indirects**																				
106																					
107	Owner Indirect	Project Development	1.0	ls	Owner														650 000	$650 000	Budget provided by LG&E

6.5 MW PV Solar - Thin Film Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS Line #	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor
108	Owner Indirect	Transmission Interconnection	1.0	ls	Owner						
109	Owner Indirect	Construction Power (Service Installation and Energy)	1.0	ls	Owner						
110	Owner Indirect	Owners Project Management	1.0	ls	Owner						
111	Owner Indirect	Owners Engineer	1.0	ls	Owner						
112	Owner Indirect	Owners Legal Counsel	1.0	ls	Owner						
113	Owner Indirect	Land	1.0	ls	Owner						
114	Owner Indirect	Startup Testing (Includes Power Sales)									
115	Owner Indirect	- Electric Transmission Firm Point to Point	1.0	ls	Owner						
116	Owner Indirect	- Startup Power	1.0	ls	Owner						
117	Owner Indirect	- Test Power Sales	1.0	ls	Owner						
118	Owner Indirect	Site Security	1.0	ls	Owner						
119	Owner Indirect	Operating Spare Parts	1.0	ls	Owner						
120	Owner Indirect	AFUDC	1.0	ls	Owner						
121		**Total Owner Indirects**									
122											
123											
124		**Owner Contingency**	15.00%	%	Owner						
125											
126											
127		**Total Owner Indirects**									
128											
129		**TOTAL PROJECT COST**									

Line #	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
108								450,000	$450,000	To be estimated by Transmision Operator
109								50 000	$50 000	Budget estimated by HDR|CB
110								500,000	$500,000	Budget provided by LG&E
111								170,000	$170,000	Budget provided by LG&E
112								250 000	$250 000	Budget provided by LG&E
113								500 000	$500 000	Budget provided by LG&E
114										
115								50,000	$50,000	Budget provided by LG&E
116								10 000	$10 000	Budget estimated by HDR|CB [10 864 MWhr @$36/MWH
117								(10,000)	($10,000)	Budget estimated by HDR|CB [432,000 MWhr @$36/MW
118								50,000	$50,000	Budget estimated by HDR|CB
119								100,000	$100,000	Budget estimated by HDR|CB
120								150,000	$150,000	AFUDC Based on 78% KU Ownership
121								**2,920,000**	**$2,920,000**	
122										
123										
124								**3,748,501**	**$3,748,501**	
125										
126										
127								**6,668,501**	**$6,668,501**	
128										
129	**0**	**11,122,504**			**3,610,678**	**67,692**	**14,733,181**	**16,925,326**	**$31,658,508**	
								$/kW	**$4,871**	

10 MW PV Solar - Standard Efficiency Crystalline Panels
E. W. Brown Station Site

BUDGET ESTIMATE

5 x 10 Work Week

February 11, 2014

Rev 0

10 MW PV Solar - Standard Efficiency Crystalline Panels

LOCATION: Kentucky
PROJECT # 221566
PLANT TYPE: **Solar PV**
CLIENT: LG&E/KU
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR:

STATUS DATE: 11-Feb-14

COST DATE BASIS: February 2013		TECHNOLOGY: Crystalline Standard Efficiency	
	NTP PERIOD:	NET MW RATING: 10.0	BOILER: N/A
	CONSTRUCTION NTP - Mob:	NO. OF UNITS: 1	STEAM TURBINE: N/A
	COMMERCIAL OPERATION DATE: 1-Dec-2016	FUEL TYPE: Solar	COOLING TYPE: N/A

	TOTAL COSTS						
DIVISION OF WORK	**Procurement Major Equipment**	**Contractor Material $**	**Contractor Labor $**	**Contractor Manhours**	**Subcontractor or Other $**	**Project Total $**	**%**
Site Preparation	$0	$831,050	$893,439	19,839	515,750	$2,240,239	7.7%
Panel Modules and Support System	$0	$8,998,875	$0	0	2,750,000	$11,748,875	40.5%
Inverter Systems	$0	$2,400,000	$173,318	2,604	0	$2,573,318	8.9%
Electrical Distribution	$0	$1,838,139	$1,978,282	40,530	0	$3,816,421	13.2%
Interconnection	$0	$200,000	$229,451	4,557	0	$429,451	1.5%
Sub-Total Direct Costs:	$0	$14,268,064	$3,274,490	67,529	$3,265,750	$20,808,304	71.8%
State Sales Tax (Non-Production Material Only)					54,222	$54,222	0.2%
Total Direct Cost	$0	$14,268,064	$3,274,490	67,529	$3,319,972	$20,862,526	72.0%
Construction Indirects & Services							
- Construction Indirects						$3,129,379	10.8%
Sub-Total Construction Indirects and Services		$0	$0	0	$0	$3,129,379	10.8%
Total Construction Cost	$0	$14,268,064	$3,274,490	67,529	$3,319,972	$23,991,905	82.8%
Estimated Subcontract Labor Hours				25,782			
Project Indirects							
- Project Engineering (Eng, PM, CM & Procurement)					$2,309,271	$2,309,271	8.0%
Sub-Total Project Indirects	$0	$0	$0	0	$2,309,271	$2,309,271	8.0%
EPC Contractor Insurance & Misc Costs							
- Builders Risk					$119,960	$119,960	0.4%
- Comprehensive General Liability (CGL) Insurance					$119,960	$119,960	0.4%
- Warranty Reserve					$50,000	$50,000	0.2%
Sub-Total EPC Contractor Insur. & Misc. Costs	$0	$0	$0	0	$289,919	$289,919	1.0%
Total EPC Contractor Project Indirect Cost	$0	$0	$0	0	$2,599,190	$2,599,190	9.0%
Sub-Total	0	14,268,064	3,274,490	93,312	5,919,162	26,591,095	91.7%
- EPC Contractor Contingency, G&A and Fe	$0	$1,426,806	$327,449		$644,935	$2,399,190	8.3%
TOTAL EPC PROJECT COST	**$0**	**$14,268,064**	**$3,274,490**	**93,312**	**$5,919,162**	**$28,990,286**	**100.0%**
EPC Price per kW						**$2,899**	
Owner Indirect Costs							
- Total Owner Indirects						$2,920,000	
- Owner Contingency						$4,348,543	
TOTAL PROJECT COST						**$36,258,829**	
Total Project Cost per kW						**$3,626**	

Total Craft Labor Hours	93,312	**erformance Guarantees:**		**Executive-in-Charge:**	**WHD**
Ave. Craft Wage without Escalation	**$51.10**	**Liquidated Damages:**		**Project Manager:**	**JPS**
Field Labor Type	**TBD**	**Special Insurance:**		**Construction Manager:**	**SMP**
Labor Productivity Factor	1.065	**Performance Bond:**		**Lead Estimator:**	**CDF**

CONFIDENTIAL

10 MW PV Solar - Standard Efficiency Crystalline Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
Line #																					
1	**Site Preparation**																				
2	Sitework	Roads - Asphalt Paving Entrance/Approach	600	sy	Sub	Contr	20.00		43.18		1.09	0	0	YES	360	0	0	0	12,000	$12,000	HDR|CB Estimated Quantity
3	Sitework	Roads - Site Roads Treated Gravel	20,000.0	sy	Contr	Contr	5.00	0.055	43.18	1,100	1.09	0	100,000	YES	6,000	51,540	1,194	151,540	0	$151,540	HDR|CB Estimated Quantity
4	Sitework	Soil Erosion Control Measures	100 000	lf	Contr	Contr	1	0.027	43.18	2 700	1.09	0	100 000	YES	6 000	126 508	2 700	226 508	0	226 508	HDR|CB Estimated Quantity
5	Sitework	Site - Topsoil stripping/stockpiling	400,000	cy	Contr	Contr		0.030	43.18	12,000	1.09	0	0	YES	0	562,259	12,000	562,259	0	$562,259	HDR|CB Estimated Quantity
6	Sitework	Site - Drainage - Pipe Culverts (Assume 12" dia)	300	lf	Contr	Contr	9.00	0.12	43.18	36	1.09	0	2,700	YES	162	1,687	36	4,387	0	$4,387	HDR|CB Estimated Quantity
9	Sitework	Utility Trench Excavation	2 000	cy	Contr	Contr		0 2	38.31	400	1.09	0	0	YES	0	16 627	400	16 627	0	$16 627	HDR|CB Estimated Quantity
12	Sitework	Spoil Disposal	0	cy	Contr	Contr		0.1	43.18	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
13	Sitework	Site Finishing - Seed Site Earthwork	45.0	ac	Contr	Contr	10 000.00	0.54	38.31	24	1.09	0	450 000	YES	27 000	1 010	26	451 010	0	$451 010	HDR|CB Estimated Quantity
14	Sitework	Site Finishing - Grading around foundations	0.0	sy	Contr	Contr		0.02	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
15	Sitework	Site Finishing - Stone Surfacing	0.0	sy	Contr	Contr	10.00	0.015	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
16	Sitework	Site Improvements - Site Entrance Sign and Landscaping	1.0	ls	Contr	Contr	18 750.00	240	38.31	240	1.09	0	18 750	YES	1 125	9 976	260	28 726	0	$28 726	HDR|CB Estimated Quantity
17	Sitework	Site Improvements - Site Security Boundary Fencing	6,000.0	lf	Contr	Contr	11.00	0 2	38.31	1,200	1.09	0	66,000	YES	3,960	49,880	1,302	115,880	0	$115,880	HDR|CB Estimated Quantity
18	Sitework	Site Surveying	1.0	lot	Sub	Contr	150,000.00	0	43.18	0	1.09	0	0	YES	4,500	0	0	0	150,000	$150,000	HDR|CB Estimated Quantity
19	Sitework	Cut and chip medium trees to 12" dia	5	acre	Sub	Contr	6 600	0	38.31	0	1.09	0	0	NO	0	0	0	0	33 000	$33 000	HDR|CB Estimated Quantity
20	Sitework	Grub stumps & remove	5	acre	Sub	Contr	4,150	0	38.31	0	1.09	0	0	NO	0	0	0	0	20,750	$20,750	HDR|CB Estimated Quantity
21	Sitework	Strip and stockpile loam or topsoil, 6", 500 ft push	30,000	cy	Sub	Contr	10.00	0	38.31	0	1.09	0	0	NO	0	0	0	0	300,000	$300,000	HDR|CB Estimated Quantity
22	Sitework	Equip Fdn - Inverter/Transformer	300	cy	Contr	Contr	260	5	38.51	1,500	1.09	0	78,000	YES	4,680	62,672	1,628	140,672	0	$140,672	HDR|CB Estimated Quantity
23	Sitework	13.8 kV Switchgear Foundation	60.0	cy	Contr	Contr	260	4 5	38.51	270	1.09	0	15 600	NO	0	11 281	293	26 881	0	$26 881	HDR|CB Estimated Quantity
24		**Site Preparation Sub-Total**								**19,470**		**0**	**831,050**		**53,787**	**893,439**	**19,839**	**1,724,489**	**515,750**	**2,240,239**	
25																					
26	**Panel Modules and Support System**																				
27																					
28	Modules	Solar Module (Multicrystalline - 300W)	39 995	ea	Contr	Contr	225.00	0	66.56	0	1.09	0	8 998 875	NO	0	0	0	8 998 875	0	$8 998 875	OEM Budget Proposal
29	Rack	Support and Mounting System (Steel Pile) incl. Module Install	1.0	ea	Sub	Contr	2 750 000	0	66.56	0	1.09	0	0	NO	0	0	0	0	2 750 000	$2 750 000	OEM Budget Proposal
30		**Panel Modules and Support Sub-Total**								**0**		**0**	**8,998,875**		**0**	**0**	**0**	**8,998,875**	**2,750,000**	**11,748,875**	
31																					
32	**Inverter Systems**																				
33																					
34	Inverter	500 kW Packaged Inverter	20.0	ea	Contr	Contr	120 000.00	120	66.56	2 400	1.09	0	2 400 000	NO	0	173 318	2 604	2 573 318	0	$2 573 318	OEM Budget Proposal
35		**Inverter Systems Sub-Total**								**2,400**		**0**	**2,400,000**		**0**	**173,318**	**2,604**	**2,573,318**	**0**	**2,573,318**	
36																					
37	**Electrical Distribution**																				
38																					
39	Electrical	Eqpt - 15 kV Switchgear (1 Main CB 3 Fused Feeders)	1.0	lot	Contr	Contr	400 000.00	635	48.81	635	1.09	0	400 000	NO	0	33 629	689	433 629	0	$433 629	HDR|CB Estimated cost
40	Electrical	Eqpt - Transformer 1 MVA, 13.8kV-300V	10.0	ea	Contr	Contr	80,000.00	210	48.81	2,100	1.09	0	800,000	NO	0	111,215	2,279	911,215	0	$911,215	HDR|CB Estimated cost
41	Electrical	Eqpt - Station Service Load Center 13,800/480 Outdoor	1.0	ea	Contr	Contr	120,000.00	160	48.81	160	1.09	0	120,000	YES	7,200	8,474	174	128,474	0	$128,474	HDR|CB Estimated cost
42	Electrical	Eqpt - Panelboards 480/120	1.0	ea	Contr	Contr	1 200.00	40.00	48.81	40	1.09	0	1 200	YES	72	2 118	43	3 318	0	$3 318	HDR|CB Estimated cost
43	Electrical	Grounding - Buried Ground Conductor	2 400	lf	Contr	Contr	4.79	0.054	48.81	130	1.09	0	11 496	NO	0	6 864	141	18 360	0	$18 360	HDR|CB Estimated Quantity & Cost
44	Electrical	Grounding - Ground Rods Copper	40	ea	Contr	Contr	22.95	1.74	48.81	70	1.09	0	918	NO	0	3,686	76	4,604	0	$4,604	HDR|CB Estimated Quantity & Cost
45	Electrical	Grounding - Exothermic Connections	160	ea	Contr	Contr	9.75	1.14	48.81	182	1.09	0	1,560	NO	0	9,660	198	11,220	0	$11,220	HDR|CB Estimated Quantity & Cost
46	Electrical	Conduit - Embedded/Direct Buried	0	lf	Contr	Contr	8.50	0.30	48.81	0	1.09	0	0	NO	0	0	0	0	0	$0	HDR|CB Estimated Quantity & Cost
47	Electrical	Cable - Medium Voltage (15kV 1C Cable)	50,000	lf	Contr	Contr	19.60	0.200	48.81	10,000	1.09	0	980,000	NO	0	529,597	10,850	1,509,597	0	$1,509,597	HDR|CB Estimated Quantity & Cost
48	Electrical	Cable Terminations - 15kV	60	ea	Contr	Contr	195.00	12.00	48.81	720	1.09	0	11,700	NO	0	38,131	781	49,831	0	$49,831	HDR|CB Estimated Quantity & Cost
49	Electrical	Cable 600V Power 1/C	124 000	lf	Contr	Contr	6.55	0.150	48.81	18 600	1.09	0	812 200	NO	0	985 050	20 181	1 797 250	0	$1 797 250	HDR|CB Estimated Quantity & Cost
50	Electrical	Wire 600V Power 3/c # 10 ave. size	1 000	lf	Contr	Contr	0.27	0.0185	48.81	19	1.09	0	270	NO	0	980	20	1 250	0	$1 250	HDR|CB Estimated Quantity & Cost
51	Electrical	Cable Terminations - low voltage	15 000	ea	Contr	Contr	0.85	0.300	48.81	4 500	1.09	0	12 750	NO	0	238 319	4 883	251 069	0	$251 069	HDR|CB Estimated Quantity & Cost
52	Electrical	Wire - Lighting 1/C No 12	4,800	lf	Contr	Contr	0.176	0.018	48.81	86	1.09	0	845	YES	51	4,576	94	5,421	0	$5,421	HDR|CB Estimated Quantity & Cost
53	Electrical	Lighting - Outdoor Fixtures, pole	4	ea	Contr	Contr	1,600.00	12.00	48.81	48	1.09	0	6,400	YES	384	2,542	52	8,942	0	$8,942	HDR|CB Estimated Quantity & Cost
54	Electrical	Electrical Circuit Testing	1,500	ea	Contr	Contr		2	48.81	3,000	1.09	0	0	NO	0	158,879	3,255	158,879	0	$158,879	HDR|CB Estimated Quantity & Cost
55		**Total Cable**	**175,000.0**	**LF**																	
56		**Electrical Distribution Sub-Total**								**37,355**		**0**	**1,838,139**		**435**	**1,978,282**	**40,530**	**3,816,421**	**0**	**3,816,421**	
57																					
58	**Division #6.2 - Interconnection**																				
59																					
60	HV Electrical	CCRT 13 2 kV Switchgear Modifications (Breaker + Metering)	1.0	lot	Contr	Contr	125 000.00	200.00	57.82	200	1.09	0	125 000	NO	0	12 547	217	137 547		$137 547	HDR|CB Estimated Quantity & Cost
61	HV Electrical	Overhead 13.8 kV Line	1.0	lot	Contr	Contr	75,000.00	3,750.00	49.98	4,000	1.09	0	75,000	NO	0	216,904	4,340	291,904		$291,904	HDR|CB Estimated Quantity & Cost
62		**Interconnection Sub-Total**								**4,200**		**0**	**$200,000**		**0**	**$229,451**	**$4,557**	**$429,451**	**$0**	**$429,451**	
63																					
64			0.0																		
65		**Sub-Total Direct Costs**								**63,425**		**0**	**14,268,064**		**54,222**	**3,274,490**	**67,529**	**17,542,554**	**3,265,750**	**20,808,304**	
66	Indirectsa	Sales Tax - State (Plant Production Equipment is Exempt)	6.00%												**54,222**				**54,222**	**54,222**	Sales Tax Included for Non-Production Facilities
67																					
68		**TOTAL DIRECT COSTS**								**63,425**		**0**	**14,268,064**			**3,274,490**	**67,529**	**17,542,554**	**3,319,972**	**$20,862,526**	
69																					
70	**Division #8.0 - Construction and Indirect Services**																				
71																					
72	Const Indirect	Construction Field Indirects	15%	%	Contr	Contr													3,129,379	$3,129,379	
73																					
74		**Construction Indirects and Services Sub-Total**								**0**		**0**	**0**			**0**	**0**	**0**	**3,129,379**	**$3,129,379**	
75																					
76		**SUB-TOTAL CONSTRUCTION COST**								**63,425**		**0**	**14,268,064**			**3,274,490**	**67,529**	**17,542,554**	**6,449,351**	**23,991,905**	
77																					
78	**Division #9.0 - Project Indirects**																				
79																					
80	Project Indirec	- Power Plant Design Engineering	1.0	ls	Contr	9.0%	2 159 271											0	2 159 271	$2 159 271	% of the Total Construction Cost
81	Project Indirec	- Geotechnical Investigation	1.0	ls	Contr		150,000											0	150,000	$150,000	Included in Engineering Contract
82																					
83																					
84		Sub-Total Project Indirects										**0**	**0**			**0**	**0**	**0**	**2,309,271**	**$2,309,271**	
85																					
86	EPC Indirects	EPC Contractor Insurance & Misc Costs (% of Total Const. Cost)																			
87																					
88	EPC Indirects	- Builders Risk Insurance	1.0	ls	Contr	0.50%	119 960												119 960	$119 960	Allowance based on info from other projects
89	EPC Indirects	- Comprehensive General Liability (CGL) Insurance	1.0	ls	Contr	0.50%	119,960											0	119,960	$119,960	Allowance based on info from other projects
90	EPC Indirects	- Warranty Reserve	1.0	ls	Contr		50,000											0	50,000	$50,000	Allowance based on info from other projects
91																					
92		Sub-Total EPC Contractor Indirects										**0**	**0**			**0**	**0**	**0**	**289,919**	**$289,919**	
93																					
94		**Total Project Indirects**										**0**	**0**			**0**	**0**	**0**	**2,599,190**	**2,599,190**	
95																					
96		Sub-Total										**0**	**14,268,064**			**3,274,490**	**67,529**	**17,542,554**	**9,048,541**	**$26,591,095**	
97							ME	Mat	Labor	S/C											
98	EPC Indirects	EPC Contractor Contingency, G&A and Fee	Varies	%	Contr		10.0%	10.0%	10.0%	10.0%		0	1,426,806			327,449		1,754,255	644,935	2,399,190	
99																					
100		Sub-Total		ls								0	1 426 806			327 449	0	1 754 255	644 935	$2 399 190	
101																					
102		**TOTAL EPC PROJECT COST**								**0**		**0**	**15,694,870**			**3,601,939**	**67,529**	**19,296,810**	**9,693,476**	**28,990,286**	
103																					
104	**OWNER INDIRECTS**																				
105	**Owner Indirects**																				
106																					
107	Owner Indirect	Project Development	1.0	ls	Owner														650 000	$650 000	Budget provided by LG&E

10 MW PV Solar - Standard Efficiency Crystalline Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS Line #	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
108	Owner Indirect	Transmission Interconnection	1.0	ls	Owner														450,000	$450,000	To be estimated by Transmision Operator
109	Owner Indirect	Construction Power (Service Installation and Energy)	1.0	ls	Owner														50 000	$50 000	Budget estimated by HDR|CB
110	Owner Indirect	Owners Project Management	1.0	ls	Owner														500,000	$500,000	Budget provided by LG&E
111	Owner Indirect	Owners Engineer	1.0	ls	Owner														170,000	$170,000	Budget provided by LG&E
112	Owner Indirect	Owners Legal Counsel	1.0	ls	Owner														250 000	$250 000	Budget provided by LG&E
113	Owner Indirect	Land	1.0	ls	Owner														500 000	$500 000	Budget provided by LG&E
114	Owner Indirect	Startup Testing (Includes Power Sales)																			
115	Owner Indirect	- Electric Transmission Firm Point to Point	1.0	ls	Owner														50,000	$50,000	Budget provided by LG&E
116	Owner Indirect	- Startup Power	1.0	ls	Owner														10 000	$10 000	Budget estimated by HDR|CB [10 864 MWhr @$36/MWH
117	Owner Indirect	- Test Power Sales	1.0	ls	Owner														(10,000)	($10,000)	Budget estimated by HDR|CB [432,000 MWhr @$36/MW
118	Owner Indirect	Site Security	1.0	ls	Owner														50,000	$50,000	Budget estimated by HDR|CB
119	Owner Indirect	Operating Spare Parts	1.0	ls	Owner														100,000	$100,000	Budget estimated by HDR|CB
120	Owner Indirect	AFUDC	1.0	ls	Owner														150,000	$150,000	AFUDC Based on 78% KU Ownership
121		**Total Owner Indirects**																	**2,920,000**	**$2,920,000**	
122																					
123																					
124		**Owner Contingency**	15.00%	%	Owner														**4,348,543**	**$4,348,543**	
125																					
126																					
127		**Total Owner Indirects**																	**7,268,543**	**$7,268,543**	
128																					
129		**TOTAL PROJECT COST**										**0**	**15,694,870**			**3,601,939**	**67,529**	**19,296,810**	**16,962,019**	**$36,258,829**	

$/kW **$3,626**

10 MW PV Solar - High Efficiency Crystalline Panels
E. W. Brown Station Site

BUDGET ESTIMATE

5 x 10 Work Week

February 11, 2014

Rev 0

CONFIDENTIAL

10 MW PV Solar - High Efficiency Crystalline Panels

LOCATION: Kentucky
PROJECT # 221566
PLANT TYPE: **Solar PV**
CLIENT: LG&E/KU
ESTIMATE TYPE: Conceptual
LEAD ESTIMATOR:

STATUS DATE: 11-Feb-14

COST DATE BASIS: February 2013		TECHNOLOGY: Crystalline Standard Efficiency	
NTP PERIOD:		NET MW RATING: 10.0	BOILER: N/A
CONSTRUCTION NTP - Mob:		NO. OF UNITS: 1	STEAM TURBINE: N/A
COMMERCIAL OPERATION DATE:	1-Dec-2016	FUEL TYPE: Solar	COOLING TYPE: N/A

DIVISION OF WORK	TOTAL COSTS Procurement Major Equipment	Contractor Material $	Contractor Labor $	Contractor Manhours	Subcontractor or Other $	Project Total $	%
Site Preparation	$0	$831,050	$893,439	19,839	515,750	$2,240,239	6.8%
Panel Modules and Support System	$0	$12,001,600	$0	0	2,750,000	$14,751,600	44.7%
Inverter Systems	$0	$2,400,000	$173,318	2,604	0	$2,573,318	7.8%
Electrical Distribution	$0	$1,838,139	$1,978,282	40,530	0	$3,816,421	11.6%
Interconnection	$0	$200,000	$229,451	4,557	0	$429,451	1.3%
Sub-Total Direct Costs:	$0	$17,270,789	$3,274,490	67,529	$3,265,750	$23,811,029	72.2%
State Sales Tax (Non-Production Material Only)					54,222	$54,222	0.2%
Total Direct Cost	$0	$17,270,789	$3,274,490	67,529	$3,319,972	$23,865,251	72.3%
Construction Indirects & Services							
- Construction Indirects						$3,579,788	10.8%
Sub-Total Construction Indirects and Services		$0	$0	0	$0	$3,579,788	10.8%
Total Construction Cost	$0	$17,270,789	$3,274,490	67,529	$3,319,972	$27,445,039	83.2%
Estimated Subcontract Labor Hours				25,782			
Project Indirects							
- Project Engineering (Eng, PM, CM & Procurement)					$2,482,828	$2,482,828	7.5%
Sub-Total Project Indirects	$0	$0	$0	0	$2,482,828	$2,482,828	7.5%
EPC Contractor Insurance & Misc Costs							
- Builders Risk					$137,225	$137,225	0.4%
- Comprehensive General Liability (CGL) Insurance					$137,225	$137,225	0.4%
- Warranty Reserve					$50,000	$50,000	0.2%
Sub-Total EPC Contractor Insur. & Misc. Costs	$0	$0	$0	0	$324,450	$324,450	1.0%
Total EPC Contractor Project Indirect Cost	$0	$0	$0	0	$2,807,279	$2,807,279	8.5%
Sub-Total	0	17,270,789	3,274,490	93,312	6,127,250	30,252,317	91.7%
- EPC Contractor Contingency, G&A and Fe	$0	$1,727,079	$327,449		$689,976	$2,744,504	8.3%
TOTAL EPC PROJECT COST	**$0**	**$17,270,789**	**$3,274,490**	**93,312**	**$6,127,250**	**$32,996,821**	**100.0%**
EPC Price per kW						**$3,300**	
Owner Indirect Costs							
- Total Owner Indirects						$2,920,000	
- Owner Contingency						$4,949,523	
TOTAL PROJECT COST						**$40,866,344**	
Total Project Cost per kW						**$4,087**	

Total Craft Labor Hours	93,312	**erformance Guarantees:**		**Executive-in-Charge:**	**WHD**
Ave. Craft Wage without Escalation	$51.10	**Liquidated Damages:**		**Project Manager:**	**JPS**
Field Labor Type	TBD	**Special Insurance:**		**Construction Manager:**	**SMP**
Labor Productivity Factor	1.065	**Performance Bond:**		**Lead Estimator:**	**CDF**

10 MW PV Solar - High Efficiency Crystalline Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
Line #																					
1	**Site Preparation**																				
2	Sitework	Roads - Asphalt Paving Entrance/Approach	600	sy	Sub	Contr	20.00		43.18		1.09	0	0	YES	360	0	0	0	12,000	$12,000	HDR|CB Estimated Quantity
3	Sitework	Roads - Site Roads Treated Gravel	20,000.0	sy	Contr	Contr	5.00	0.055	43.18	1,100	1.09	0	100,000	YES	6,000	51,540	1,194	151,540	0	$151,540	HDR|CB Estimated Quantity
4	Sitework	Soil Erosion Control Measures	100 000	lf	Contr	Contr	1	0.027	43.18	2 700	1.09	0	100 000	YES	6 000	126 508	2 700	226 508	0	226 508	HDR|CB Estimated Quantity
5	Sitework	Site - Topsoil stripping/stockpiling	400,000	cy	Contr	Contr		0.030	43.18	12,000	1.09	0	0	YES	0	562,259	12,000	562,259	0	$562,259	HDR|CB Estimated Quantity
6	Sitework	Site - Drainage - Pipe Culverts (Assume 12" dia)	300	lf	Contr	Contr	9.00	0.12	43.18	36	1.09	0	2,700	YES	162	1,687	36	4,387	0	$4,387	HDR|CB Estimated Quantity
9	Sitework	Utility Trench Excavation	2 000	cy	Contr	Contr		0 2	38.31	400	1.09	0	0	YES	0	16 627	400	16 627	0	$16 627	HDR|CB Estimated Quantity
12	Sitework	Spoil Disposal	0	cy	Contr	Contr		0.1	43.18	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
13	Sitework	Site Finishing - Seed Site Earthwork	45.0	ac	Contr	Contr	10 000.00	0.54	38.31	24	1.09	0	450 000	YES	27 000	1 010	26	451 010	0	$451 010	HDR|CB Estimated Quantity
14	Sitework	Site Finishing - Grading around foundations	0.0	sy	Contr	Contr		0.02	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
15	Sitework	Site Finishing - Stone Surfacing	0.0	sy	Contr	Contr	10.00	0.015	38.31	0	1.09	0	0	YES	0	0	0	0	0	$0	HDR|CB Estimated Quantity
16	Sitework	Site Improvements - Site Entrance Sign and Landscaping	1.0	ls	Contr	Contr	18 750.00	240	38.31	240	1.09	0	18 750	YES	1 125	9 976	260	28 726	0	$28 726	HDR|CB Estimated Quantity
17	Sitework	Site Improvements - Site Security Boundary Fencing	6,000.0	lf	Contr	Contr	11.00	0 2	38.31	1,200	1.09	0	66,000	YES	3,960	49,880	1,302	115,880	0	$115,880	HDR|CB Estimated Quantity
18	Sitework	Site Surveying	1.0	lot	Sub	Contr	150,000.00	0	43.18	0	1.09	0	0	YES	4,500	0	0	0	150,000	$150,000	HDR|CB Estimated Quantity
19	Sitework	Cut and chip medium trees to 12" dia	5	acre	Sub	Contr	6 600	0	38.31	0	1.09	0	0	NO	0	0	0	0	33 000	$33 000	HDR|CB Estimated Quantity
20	Sitework	Grub stumps & remove	5	acre	Sub	Contr	4,150	0	38.31	0	1.09	0	0	NO	0	0	0	0	20,750	$20,750	HDR|CB Estimated Quantity
21	Sitework	Strip and stockpile loam or topsoil, 6", 500 ft push	30,000	cy	Sub	Contr	10.00	0	38.31	0	1.09	0	0	NO	0	0	0	0	300,000	$300,000	HDR|CB Estimated Quantity
22	Sitework	Equip Fdn - Inverter/Transformer	300	cy	Contr	Contr	260	5	38.51	1,500	1.09	0	78,000	YES	4,680	62,672	1,628	140,672	0	$140,672	HDR|CB Estimated Quantity
23	Sitework	13.8 kV Switchgear Foundation	60.0	cy	Contr	Contr	260	4 5	38.51	270	1.09	0	15 600	NO	0	11 281	293	26 881	0	$26 881	HDR|CB Estimated Quantity
24		**Site Preparation Sub-Total**								**19,470**		**0**	**831,050**		**53,787**	**893,439**	**19,839**	**1,724,489**	**515,750**	**2,240,239**	
25																					
26	**Panel Modules and Support System**																				
27																					
28	Modules	Solar Module (Multicrystalline - 300W)	37 505	ea	Contr	Contr	320.00	0	66.56	0	1.09	0	12 001 600	NO	0	0	0	12 001 600	0	$12 001 600	OEM Budget Proposal
29	Rack	Support and Mounting System (Steel Pile) incl. Module Install	1.0	ea	Sub	Contr	2 750 000	0	66.56	0	1.09	0	0	NO	0	0	0	0	2 750 000	$2 750 000	OEM Budget Proposal
30		**Panel Modules and Support Sub-Total**								**0**		**0**	**12,001,600**		**0**	**0**	**0**	**12,001,600**	**2,750,000**	**14,751,600**	
31																					
32	**Inverter Systems**																				
33																					
34	Inverter	500 kW Packaged Inverter	20.0	ea	Contr	Contr	120 000.00	120	66.56	2 400	1.09	0	2 400 000	NO	0	173 318	2 604	2 573 318	0	$2 573 318	OEM Budget Proposal
35		**Inverter Systems Sub-Total**								**2,400**		**0**	**2,400,000**		**0**	**173,318**	**2,604**	**2,573,318**	**0**	**2,573,318**	
36																					
37	**Electrical Distribution**																				
38																					
39	Electrical	Eqpt - 15 kV Switchgear (1 Main CB 3 Fused Feeders)	1.0	lot	Contr	Contr	400 000.00	635	48.81	635	1.09	0	400 000	NO	0	33 629	689	433 629	0	$433 629	HDR|CB Estimated cost
40	Electrical	Eqpt - Transformer 1 MVA, 13.8kV-300V	10.0	ea	Contr	Contr	80,000.00	210	48.81	2,100	1.09	0	800,000	NO	0	111,215	2,279	911,215	0	$911,215	HDR|CB Estimated cost
41	Electrical	Eqpt - Station Service Load Center 13,800/480 Outdoor	1.0	ea	Contr	Contr	120,000.00	160	48.81	160	1.09	0	120,000	YES	7,200	8,474	174	128,474	0	$128,474	HDR|CB Estimated cost
42	Electrical	Eqpt - Panelboards 480/120	1.0	ea	Contr	Contr	1 200.00	40.00	48.81	40	1.09	0	1 200	YES	72	2 118	43	3 318	0	$3 318	HDR|CB Estimated cost
43	Electrical	Grounding - Buried Ground Conductor	2 400	lf	Contr	Contr	4.79	0.054	48.81	130	1.09	0	11 496	NO	0	6 864	141	18 360	0	$18 360	HDR|CB Estimated Quantity & Cost
44	Electrical	Grounding - Ground Rods Copper	40	ea	Contr	Contr	22.95	1.74	48.81	70	1.09	0	918	NO	0	3,686	76	4,604	0	$4,604	HDR|CB Estimated Quantity & Cost
45	Electrical	Grounding - Exothermic Connections	160	ea	Contr	Contr	9.75	1.14	48.81	182	1.09	0	1,560	NO	0	9,660	198	11,220	0	$11,220	HDR|CB Estimated Quantity & Cost
46	Electrical	Conduit - Embedded/Direct Buried	0	lf	Contr	Contr	8.50	0.30	48.81	0	1.09	0	0	NO	0	0	0	0	0	$0	HDR|CB Estimated Quantity & Cost
47	Electrical	Cable - Medium Voltage (15kV 1C Cable)	50,000	lf	Contr	Contr	19.60	0.200	48.81	10,000	1.09	0	980,000	NO	0	529,597	10,850	1,509,597	0	$1,509,597	HDR|CB Estimated Quantity & Cost
48	Electrical	Cable Terminations - 15kV	60	ea	Contr	Contr	195.00	12.00	48.81	720	1.09	0	11,700	NO	0	38,131	781	49,831	0	$49,831	HDR|CB Estimated Quantity & Cost
49	Electrical	Cable 600V Power 1/C	124 000	lf	Contr	Contr	6.55	0.150	48.81	18 600	1.09	0	812 200	NO	0	985 050	20 181	1 797 250	0	$1 797 250	HDR|CB Estimated Quantity & Cost
50	Electrical	Wire 600V Power 3/c # 10 ave. size	1 000	lf	Contr	Contr	0.27	0.0185	48.81	19	1.09	0	270	NO	0	980	20	1 250	0	$1 250	HDR|CB Estimated Quantity & Cost
51	Electrical	Cable Terminations - low voltage	15 000	ea	Contr	Contr	0.85	0.300	48.81	4 500	1.09	0	12 750	NO	0	238 319	4 883	251 069	0	$251 069	HDR|CB Estimated Quantity & Cost
52	Electrical	Wire - Lighting 1/C No 12	4,800	lf	Contr	Contr	0.176	0.018	48.81	86	1.09	0	845	YES	51	4,576	94	5,421	0	$5,421	HDR|CB Estimated Quantity & Cost
53	Electrical	Lighting - Outdoor Fixtures, pole	4	ea	Contr	Contr	1,600.00	12.00	48.81	48	1.09	0	6,400	YES	384	2,542	52	8,942	0	$8,942	HDR|CB Estimated Quantity & Cost
54	Electrical	Electrical Circuit Testing	1,500	ea	Contr	Contr		2	48.81	3,000	1.09	0	0	NO	0	158,879	3,255	158,879	0	$158,879	HDR|CB Estimated Quantity & Cost
55		**Total Cable**	**175,000.0**	**LF**																	
56		**Electrical Distribution Sub-Total**								**37,355**		**0**	**1,838,139**		**435**	**1,978,282**	**40,530**	**3,816,421**	**0**	**3,816,421**	
57																					
58	**Division #6.2 - Interconnection**																				
59																					
60	HV Electrical	CCRT 13 2 kV Switchgear Modifications (Breaker + Metering)	1.0	lot	Contr	Contr	125 000.00	200.00	57.82	200	1.09	0	125 000	NO	0	12 547	217	137 547		$137 547	HDR|CB Estimated Quantity & Cost
61	HV Electrical	Overhead 13.8 kV Line	1.0	lot	Contr	Contr	75,000.00	3,750.00	49.98	4,000	1.09	0	75,000	NO	0	216,904	4,340	291,904		$291,904	HDR|CB Estimated Quantity & Cost
62		**Interconnection Sub-Total**								**4,200**		**0**	**$200,000**		**0**	**$229,451**	**$4,557**	**$429,451**	**$0**	**$429,451**	
63																					
64			0.0																		
65		**Sub-Total Direct Costs**								**63,425**		**0**	**17,270,789**		**54,222**	**3,274,490**	**67,529**	**20,545,279**	**3,265,750**	**23,811,029**	
66	Indirectsa	Sales Tax - State (Plant Production Equipment is Exempt)	6.00%												**54,222**				**54,222**	**54,222**	Sales Tax Included for Non-Production Facilities
67																					
68		**TOTAL DIRECT COSTS**								**63,425**		**0**	**17,270,789**			**3,274,490**	**67,529**	**20,545,279**	**3,319,972**	**$23,865,251**	
69																					
70	**Division #8.0 - Construction and Indirect Services**																				
71																					
72	Const Indirect	Construction Field Indirects	15%	%	Contr	Contr													3,579,788	$3,579,788	
73																					
74		**Construction Indirects and Services Sub-Total**								**0**		**0**	**0**			**0**	**0**	**0**	**3,579,788**	**$3,579,788**	
75																					
76		**SUB-TOTAL CONSTRUCTION COST**								**63,425**		**0**	**17,270,789**			**3,274,490**	**67,529**	**20,545,279**	**6,899,759**	**27,445,039**	
77																					
78	**Division #9.0 - Project Indirects**																				
79																					
80	Project Indirec	- Power Plant Design Engineering	1.0	ls	Contr	8.5%	2 332 828											0	2 332 828	$2 332 828	% of the Total Construction Cost
81	Project Indirec	- Geotechnical Investigation	1.0	ls	Contr		150,000											0	150,000	$150,000	Included in Engineering Contract
82																					
83																					
84		Sub-Total Project Indirects										**0**	**0**			**0**	**0**	**0**	**2,482,828**	**$2,482,828**	
85																					
86	EPC Indirects	EPC Contractor Insurance & Misc Costs (% of Total Const. Cost)																			
87																					
88	EPC Indirects	- Builders Risk Insurance	1.0	ls	Contr	0.50%	137 225												137 225	$137 225	Allowance based on info from other projects
89	EPC Indirects	- Comprehensive General Liability (CGL) Insurance	1.0	ls	Contr	0.50%	137,225											0	137,225	$137,225	Allowance based on info from other projects
90	EPC Indirects	- Warranty Reserve	1.0	ls	Contr		50,000											0	50,000	$50,000	Allowance based on info from other projects
91																					
92		Sub-Total EPC Contractor Indirects										**0**	**0**			**0**	**0**	**0**	**324,450**	**$324,450**	
93																					
94		**Total Project Indirects**										**0**	**0**			**0**	**0**	**0**	**2,807,279**	**2,807,279**	
95																					
96		Sub-Total										**0**	**17,270,789**			**3,274,490**	**67,529**	**20,545,279**	**9,707,038**	**$30,252,317**	
97							ME	Mat	Labor	S/C											
98	EPC Indirects	EPC Contractor Contingency, G&A and Fee	Varies	%	Contr		10.0%	10.0%	10.0%	10.0%		0	1,727,079			327,449		2,054,528	689,976	2,744,504	
99																					
100		Sub-Total		ls								0	1 727 079			327 449	0	2 054 528	689 976	$2 744 504	
101																					
102		**TOTAL EPC PROJECT COST**								**0**		**0**	**18,997,868**			**3,601,939**	**67,529**	**22,599,807**	**10,397,014**	**32,996,821**	
103																					
104	**OWNER INDIRECTS**																				
105	**Owner Indirects**																				
106																					
107	Owner Indirect	Project Development	1.0	ls	Owner														650 000	$650 000	Budget provided by LG&E

10 MW PV Solar - High Efficiency Crystalline Panels

Kentucky
Solar PV
LG&E/KU
Conceptual

STATUS DATE: 11-Feb-14

T DATE BASIS	DISCIPLINE	DESCRIPTION	Qty	UM	D.O.R. Purch. Resp.	Const. Resp.	MATERIAL Purchase or Unit Cost	INSTALL. Labor MH/UM	Labor Wage Rate	Manhours w/o productivity	Prod. Factor	PROCUREMENT MAJOR EQUIP. TOTAL $	CONSTRUCTION PROJECT TOTALS CONTRACTOR MATERIAL $	TAXABLE	SALES TAX $	LABOR $	MHRS	SUBTOTAL $	SUBCONT or OTHER $	PROJECT TOTAL $	BASIS NOTES
Line #																					
108	Owner Indirect	Transmission Interconnection	1.0	ls	Owner														450,000	$450,000	To be estimated by Transmision Operator
109	Owner Indirect	Construction Power (Service Installation and Energy)	1.0	ls	Owner														50 000	$50 000	Budget estimated by HDR|CB
110	Owner Indirect	Owners Project Management	1.0	ls	Owner														500,000	$500,000	Budget provided by LG&E
111	Owner Indirect	Owners Engineer	1.0	ls	Owner														170,000	$170,000	Budget provided by LG&E
112	Owner Indirect	Owners Legal Counsel	1.0	ls	Owner														250 000	$250 000	Budget provided by LG&E
113	Owner Indirect	Land	1.0	ls	Owner														500 000	$500 000	Budget provided by LG&E
114	Owner Indirect	Startup Testing (Includes Power Sales)																			
115	Owner Indirect	- Electric Transmission Firm Point to Point	1.0	ls	Owner														50,000	$50,000	Budget provided by LG&E
116	Owner Indirect	- Startup Power	1.0	ls	Owner														10 000	$10 000	Budget estimated by HDR|CB [10 864 MWhr @$36/MWH
117	Owner Indirect	- Test Power Sales	1.0	ls	Owner														(10,000)	($10,000)	Budget estimated by HDR|CB [432,000 MWhr @$36/MW
118	Owner Indirect	Site Security	1.0	ls	Owner														50,000	$50,000	Budget estimated by HDR|CB
119	Owner Indirect	Operating Spare Parts	1.0	ls	Owner														100,000	$100,000	Budget estimated by HDR|CB
120	Owner Indirect	AFUDC	1.0	ls	Owner														150,000	$150,000	AFUDC Based on 78% KU Ownership
121		**Total Owner Indirects**																	**2,920,000**	**$2,920,000**	
122																					
123																					
124		**Owner Contingency**	15.00%	%	Owner														**4,949,523**	**$4,949,523**	
125																					
126																					
127		**Total Owner Indirects**																	**7,869,523**	**$7,869,523**	
128																					
129		**TOTAL PROJECT COST**										**0**	**18,997,868**			**3,601,939**	**67,529**	**22,599,807**	**18,266,537**	**$40,866,344**	

$/kW **$4,087**

APPENDIX F

LIFE CYCLE COST ANALYSIS

- 6.5 MW PV Solar Tin Film Panel Life Cycle Cost Analysis
- 10 MW PV Solar Standard Efficiency Crystalline Panel Life Cycle Cost Analysis
- 10 MW PV Solar High Efficiency Crystalline Panel Life Cycle Cost Analysis

HDR
LG&E - KU
PROJECT: 221566 EW BROWN SOLAR
DATE: 2/12/2014 9:32
FILE: SHEET 1

PLANT DESIGN: 10 MW PV Solar - Multicrrystalline Standard Efficiency

PLANT GROSS CAPACITY	NEW & CLEAN	6,500 KW-AC	8125 kW - DC
NET CONTRACT DEMAND		6,500 KW-AC	
HEAT RATE - GROSS HHV		0 BTU/KWH	
HEAT RATE - NET HHV		0 BTU/KWH	

CAPITAL COST CATEGORIES:	($1,000)	
HARD COSTS:		
EPC PLANT		$25,000
SOFT COSTS:		
TOTAL OWNER INDIRECTS		$2,920
OWNER CONTINGENCY		$3,750
PROJECT MANAGEMENT		$0
ENGINEERING SUPPORT		$0
FINANCE FEE	0.015	$0
AFUDC	0.0404083	$0
CONSTRUCTION MNGMT		$0
OWNER CONTINGENCY	0.1	$0
PLANT OPS		$0
INSURANCE	CONST	$0
ESCALATION ALLOWANCE		$0
SUB-TOTAL	21.06%	$6,670
TOTAL PROJECT COST		$31,670
INSTALLED POWER PLANT COST ($/KW)		$3,898 $/kW-DC
		$4,872.31

FINANCE STRUCTURE:			
DEBT		AVG DCR	1.94
PERCENT		$14,464	46%
RATE			3.73%
TERM	20 YR		80
PAYMENT - QUARTER			$257
EQUITY			
PERCENT		$17,206	54%
POST-TAX RETURN		(TARGET)	5.24%
EQUITY PAYMENT			$902 GOAL SEEK IRR=3.73% UNLEVERED
		IRR	6.58%
		NPV	($186)

DEPRECIATION	NEW PLANT - UTILITY	20	YR MACRS
AMORTIZATION		30	YRS
DISCOUNT RATE		6.75%	
PROJECT LIFE		30	YRS

PRO FORMA ANALYSIS:

YEAR			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ESCALATORS:																		
PARTS			2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
CONSUMABLE ESC.			0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
UNIT COST DATA:																		
FUEL																		
NATURAL GAS	($/MMBTU)		$11.70	$4.96	$5.31	$5.66	$6.06	$6.53	$6.91	$7.22	$7.59	$7.93	$8.32	$8.62	$8.99	$9.38	$9.80	$10.28
NATURAL GAS ANNUAL DEMAND CHARGE			($1,000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
0 PRICING OPTIONS	MARGINAL																	
$216.94 POWER	CAPITAL RECOVERY	($/MWH)		$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94
	FIXED CAPACITY-DB	($/KW-MO)		$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20
	FIXED CAPACITY-EQ	($/KW-MO)		$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56
$9.54	OP COST	($/MWH)		$9.68	$9.66	$9.64	$9.62	$9.60	$9.59	$9.57	$9.55	$9.54	$9.52	$9.51	$9.49	$9.48	$9.47	$9.46
$0.00 30 YR - LEVELIZED	FUEL COST POWER	($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
61.53 $226.48	TOTAL COST	($/MWH)		$226.62	$226.60	$226.58	$226.56	$226.54	$226.52	$226.51	$226.49	$226.47	$226.46	$226.44	$226.43	$226.42	$226.41	$226.40
$226.48	TOLLED COST	($/MWH)		$226.62	$226.60	$226.58	$226.56	$226.54	$226.52	$226.51	$226.49	$226.47	$226.46	$226.44	$226.43	$226.42	$226.41	$226.40
PRODUCTION DATA:			AVERAGE	0.226618004														
ELECTRIC ENERGY	(MWH)		8,901	10429	10323	10218	10113	10007	9902	9797	9691	9586	9481	9375	9270	9164	9059	8954
TOTAL ELECTRIC	(MWH)		8,901	10429	10323	10218	10113	10007	9902	9797	9691	9586	9481	9375	9270	9164	9059	8954
FCP FUEL	(MMBTU)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	(MMBTU)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG HEAT RATE	(BTU/KWH)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG OUTPUT	(KW)			1190	1178	1166	1154	1142	1130	1118	1106	1094	1082	1070	1058	1046	1034	1022
CAPACITY FACTOR	(%)	FIRM	15.63%	18.32%	18.13%	17.95%	17.76%	17.58%	17.39%	17.21%	17.02%	16.84%	16.65%	16.47%	16.28%	16.10%	15.91%	15.73%
AMMONIA	(TON)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAKEUP WATER	(K-GALLONS)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOWER MAKEUP	(K-GALLONS)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WASTE WATER	(K-GALLONS)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	(TON)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	(TON)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

YEAR	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
PARTS	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
CONSUMABLE ESC.	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
NATURAL GAS	$10.68	$11.46	$12.23	$12.84	$13.48	$14.15	$14.85	$15.60	$16.37	$17.19	$17.90	$18.77	$19.67	$20.61	$21.59
NATURAL GAS ANNUAL DEMAND CHARGE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPITAL RECOVERY	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94	$216.94
FIXED CAPACITY-DB	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20	$13.20
FIXED CAPACITY-EQ	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56	$11.56
OP COST	$9.45	$9.44	$9.43	$9.43	$9.42	$9.42	$9.42	$9.42	$9.42	$9.42	$9.43	$9.44	$9.45	$9.46	$9.48
FUEL COST POWER	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL COST	$226.39	$226.38	$226.37	$226.36	$226.36	$226.36	$226.36	$226.36	$226.36	$226.36	$226.37	$226.38	$226.39	$226.40	$226.41
TOLLED COST	$226.39	$226.38	$226.37	$226.36	$226.36	$226.36	$226.36	$226.36	$226.36	$226.36	$226.37	$226.38	$226.39	$226.40	$226.41
ELECTRIC ENERGY	8848	8743	8638	8532	8427	8322	8216	8111	8006	7900	7795	7690	7584	7479	7374
TOTAL ELECTRIC	8848	8743	8638	8532	8427	8322	8216	8111	8006	7900	7795	7690	7584	7479	7374
FCP FUEL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG HEAT RATE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG OUTPUT	1010	998	986	974	962	950	938	926	914	902	890	878	866	854	842
CAPACITY FACTOR	15.54%	15.36%	15.17%	14.99%	14.80%	14.62%	14.43%	14.25%	14.06%	13.88%	13.69%	13.51%	13.32%	13.14%	12.95%
AMMONIA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAKEUP WATER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOWER MAKEUP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WASTE WATER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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PROJECT: 221566 EW BROWN SOLAR
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REVENUE: ($1,000)

			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPACITY FIXED		$24.76	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931
ENERGY																	
	VARIABLE ENERGY		$100.96	99.73285	98.51799	97.311977	96.115025	94.927349	93.749173	92.580724	91.422237	90.273951	89.136109	88.008963	86.89277	85.787792	84.694299
	FUEL		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE		$25,716	$2,032	$2,031	$2,030	$2,028	$2,027	$2,026	$2,025	$2,024	$2,022	$2,021	$2,020	$2,019	$2,018	$2,017	$2,016

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CAPACITY FIXED	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931
VARIABLE ENERGY	83.612565	82.542875	81.485515	80.440783	79.408982	78.390421	77.385418	76.3943001	75.4173989	74.4550561	73.507621	72.5754515	71.6589139	70.7583835	69.8742443
FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE	$2,015	$2,014	$2,012	$2,011	$2,010	$2,009	$2,008	$2,007	$2,006	$2,005	$2,004	$2,004	$2,003	$2,002	$2,001

PRO FORMA ANALYSIS:

YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30

EXPENSES: ($1,000)

			Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10	Y11	Y12	Y13	Y14	Y15	Y16	Y17	Y18	Y19	Y20	Y21	Y22	Y23	Y24	Y25	Y26	Y27	Y28	Y29	Y30
NATURAL GAS CONSUMPTION			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS ANNUAL DEMAND CHARGE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT COST ($/MWH)			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMMONIA			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CLARIFIED WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMIN WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CHEMICAL FEED			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STARTUP FUEL			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE MAINTENANCE PARTS AND LABOR			$15	$15	$16	$16	$16	$17	$17	$18	$18	$19	$19	$19	$20	$20	$21	$21	$22	$22	$23	$24	$24	$25	$25	$26	$27	$27	$28	$28	$29	$30
FIXED MAINTENANCE PARTS AND LABOR			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O&M	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MISC EXPENSES			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INSURANCES			$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
PROPERTY TAXES			$46	$44	$43	$41	$40	$38	$36	$35	$33	$32	$30	$29	$27	$25	$24	$22	$21	$19	$17	$16	$14	$13	$11	$10	$8	$6	$5	$3	$2	$0
LAND LEASE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		LEVELIZED																														
Fixed ($/MWH)	$13	$7.42	$8.24	8.1711892	8.1004549	8.0282469	7.9545188	7.879222	7.8023059	7.7237177	7.6434023	7.5613021	7.4773569	7.391504	7.3036774	7.2138083	7.1218246	7.0276509	6.9312079	6.8324126	6.731178	6.6274124	6.52102	6.4118995	6.29994466	6.18504368	6.06707867	5.94592542	5.8214529	5.69352282	5.56198907	5.42669721
Variable ($/MWH)	$2	$2.11	1.438357603	1.4879076	1.5393247	1.592688	1.64808	1.7055875	1.7653014	1.8273172	1.8917351	1.9586605	2.028204	2.1004818	2.1756163	2.2537361	2.3349766	2.4194805	2.507398	2.5988875	2.6941159	2.7932593	2.8965038	3.0040458	3.11609284	3.23286432	3.35459244	3.48152296	3.61391622	3.75204813	3.89621133	4.04671641
Consumables ($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		NPV																														
TOTAL OPERATING COST		$1,140	$101	$100	$99	$97	$96	$95	$94	$93	$91	$90	$89	$88	$87	$86	$85	$84	$83	$81	$80	$79	$78	$77	$76	$75	$74	$74	$73	$72	$71	$70
UNIT COST ($/MWH)		$9.54	$9.68	$9.66	$9.64	$9.62	$9.60	$9.59	$9.57	$9.55	$9.54	$9.52	$9.51	$9.49	$9.48	$9.47	$9.46	$9.45	$9.44	$9.43	$9.43	$9.42	$9.42	$9.42	$9.42	$9.42	$9.42	$9.43	$9.44	$9.45	$9.46	$9.48
NET OPERATING INCOME		$24,576	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931
20 YR DEPRECIATION	$0	0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 YR ACCELERATED DEPRECIATION	$25,076	100%	$5,000	$8,075	$4,800	$2,880	$2,880	$1,441																								
* Note, if 30% ITC is applied, then only 85 % of the project can be app ied to this depreciation schedule and 15% is applied to 20 yr depreciation																																
AMORTIZATION	$25,076		$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222
BOOK DEPRECIATION			$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056	$1,056
TOTAL CUMULATIVE DEP/AMORT			$1,056	$2,111	$3,167	$4,223	$5,278	$6,334	$7,390	$8,445	$9,501	$10,557	$11,612	$12,668	$13,724	$14,779	$15,835	$16,891	$17,946	$19,002	$20,058	$21,113	$22,169	$23,225	$24,280	$25,336	$26,392	$27,447	$28,503	$29,559	$30,614	$31,670
NET BOOK VALUE			$30,614	$29,559	$28,503	$27,447	$26,392	$25,336	$24,280	$23,225	$22,169	$21,113	$20,058	$19,002	$17,946	$16,891	$15,835	$14,779	$13,724	$12,668	$11,612	$10,557	$9,501	$8,445	$7,390	$6,334	$5,278	$4,223	$3,167	$2,111	$1,056	$0
TOTAL NON-CASH CHARGES			$5,222	$8,297	$5,022	$3,102	$3,102	$1,663	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222	$222
UNIT COST ($/MWH)	EXPENSE		$500.77	$803.75	$491.52	$306.78	$310.01	$167.96	$22.70	$22.94	$23.19	$23.45	$23.72	$23.98	$24.26	$24.54	$24.83	$25.13	$25.43	$25.74	$26.06	$26.38	$26.72	$27.06	$27.41	$27.77	$28.14	$28.52	$28.91	$29.31	$29.73	$30.15
EARNINGS BEFORE INTEREST & TAXES (EBIT)			-$3,291	-$6,366	-$3,091	-$1,171	-$1,171	$268	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709
DEBT SERVICE:												10 YR					15 YR					20 YR					25 YR					30 YR
TOTAL PAYMENT			$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$1,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INTEREST PAYMENT			$533	$514	$494	$474	$453	$431	$409	$385	$361	$336	$309	$282	$254	$224	$194	$162	$130	$96	$60	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRINCIPAL PAYMENTS			$497	$516	$535	$555	$576	$598	$621	$644	$669	$694	$720	$747	$776	$805	$835	$867	$900	$934	$969	$1,006	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TAX BASIS			($3,824)	($6,880)	($3,586)	($1,645)	($1,624)	($163)	$1,300	$1,323	$1,348	$1,373	$1,399	$1,427	$1,455	$1,484	$1,515	$1,546	$1,579	$1,613	$1,648	$1,685	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709	$1,709
INCOME TAXES																																
US	38.90%		($1,488)	($2,676)	($1,395)	($640)	($632)	($64)	$506	$515	$524	$534	$544	$555	$566	$577	$589	$602	$614	$628	$641	$656	$665	$665	$665	$665	$665	$665	$665	$665	$665	$665
GROSS RECIEPTS	0.00%		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	10.00%		($2,500)																													
CASH BASIS:																																
NET OPERATING INCOME (NOI)			$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931
		NPV																														
NET BEFORE TAX CASHFLOW		$13,456	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$902	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931	$1,931
		NPV																														
LESS TAXES		$3,565	$3,988	$2,676	$1,395	$640	$632	$64	($506)	($515)	($524)	($534)	($544)	($555)	($566)	($577)	($589)	($602)	($614)	($628)	($641)	($656)	($665)	($665)	($665)	($665)	($665)	($665)	($665)	($665)	($665)	($665)
NET AFTER TAX CASH		($17,206)	$4,889	$3,578	$2,296	$1,542	$1,534	$965	$396	$387	$377	$367	$357	$347	$336	$324	$312	$300	$287	$274	$260	$246	$1,266	$1,266	$1,266	$1,266	$1,266	$1,266	$1,266	$1,266	$1,266	$1,266
	NPV	($186)																														
	IRR	6.58%																														
DEBT SERVICE COVERAGE		AVERAGE																														
AFTER TAX		1.94	5.75	4.48	3.23	2.50	2.49	1.94	1.38	1.38	1.37	1.36	1.35	1.34	1.33	1.31	1.30	1.29	1.28	1.27	1.25	1.24	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
BEFORE TAX		1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
EQUITY RETURN:	100%																															
PRE-TAX			5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%
	AVG	ROIC 7.23%																														
POST-TAX			28.41%	20.79%	13.35%	8.96%	8.91%	5.61%	2.30%	2.25%	2.19%	2.14%	2.08%	2.01%	1.95%	1.88%	1.82%	1.74%	1.67%	1.59%	1.51%	1.43%	7.36%	7.36%	7.36%	7.36%	7.36%	7.36%	7.36%	7.36%	7.36%	7.36%
	AVG	ROIC 6.21%																														
HDR		ROA	18.49%	15.31%	8.62%	5.40%	5.37%	3.22%	1.26%	1.23%	1.20%	1.17%	1.14%	1.10%	1.07%	1.03%	0.99%	0.95%	0.91%	0.87%	0.83%	0.78%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%	4.03%
LG&E - KU		20 YR - AVG	3.55%																													
PROJECT:	221566 EW BROWN SOLAR	40 YR - AVG	3.71%																													
DATE:	2/12/2014 9:32																															
FILE:	0																															

HDR		
LG&E - KU		
PROJECT:	221566	EW BROWN SOLAR
DATE:	2/12/2014 9:34	
FILE:		SHEET 1

PLANT DESIGN: 10 MW PV Solar - Multicrrystalline Standard Efficiency

PLANT GROSS CAPACITY	NEW & CLEAN	10,000 KW-AC	12500 kW - DC
NET CONTRACT DEMAND		10,000 KW-AC	
HEAT RATE - GROSS HHV		0 BTU/KWH	
HEAT RATE - NET HHV		0 BTU/KWH	

CAPITAL COST CATEGORIES:		($1,000)
HARD COSTS:		
EPC PLANT		$29,000
SOFT COSTS:		
TOTAL OWNER INDIRECTS		$2,920
OWNER CONTINGENCY		$4,350
PROJECT MANAGEMENT		$0
ENGINEERING SUPPORT		$0
FINANCE FEE	0.015	$0
AFUDC	0.0404083	$0
CONSTRUCTION MNGMT		$0
OWNER CONTINGENCY	0.1	$0
PLANT OPS		$0
INSURANCE	CONST	$0
ESCALATION ALLOWANCE		$0
SUB-TOTAL	20.04%	$7,270
TOTAL PROJECT COST		$36,270
INSTALLED POWER PLANT COST ($/KW)		$2,902 $/kW-DC
		$3,627.00

FINANCE STRUCTURE:			
DEBT		AVG DCR	1.94
PERCENT		$16,565	46%
RATE			3.73%
TERM	20 YR		80
PAYMENT - QUARTER			$295
EQUITY			
PERCENT		$19,705	54%
POST-TAX RETURN		(TARGET)	5.24%
EQUITY PAYMENT			$1,033 GOAL SEEK IRR=3.73% UNLEVERED
		IRR	6.65%
		NPV	($119)

DEPRECIATION	NEW PLANT - UTILITY	20 YR MACRS
AMORTIZATION		30 YRS
DISCOUNT RATE		6.75%
PROJECT LIFE		30 YRS

PRO FORMA ANALYSIS:

	YEAR		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	ESCALATORS:																																
	PARTS			2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
	CONSUMABLE ESC.			0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
	UNIT COST DATA:																																
	FUEL																																
	NATURAL GAS	($/MMBTU)	$11.70	$4.96	$5.31	$5.66	$6.06	$6.53	$6.91	$7.22	$7.59	$7.93	$8.32	$8.62	$8.99	$9.38	$9.80	$10.28	$10.68	$11.46	$12.23	$12.84	$13.48	$14.15	$14.85	$15.60	$16.37	$17.19	$17.90	$18.77	$19.67	$20.61	$21.59
	NATURAL GAS ANNUAL DEMAND CHARGE		($1,000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
0	PRICING OPTIONS	MARGINAL																															
$170.23	POWER	CAPITAL RECOVERY ($/MWH)		$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23	$170.23
		FIXED CAPACITY-DB ($/KW-MO)		$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82	$9.82
		FIXED CAPACITY-EQ ($/KW-MO)		$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60	$8.60
$6.85		OP COST ($/MWH)		$7.07	$7.05	$7.02	$7.00	$6.97	$6.95	$6.93	$6.90	$6.88	$6.86	$6.83	$6.81	$6.79	$6.77	$6.75	$6.72	$6.70	$6.68	$6.66	$6.64	$6.62	$6.61	$6.59	$6.57	$6.56	$6.54	$6.53	$6.52	$6.50	$6.49
$0.00	30 YR - LEVELIZED	FUEL COST POWER ($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
61.53	$177.08	TOTAL COST ($/MWH)		$177.30	$177.28	$177.25	$177.23	$177.21	$177.18	$177.16	$177.14	$177.11	$177.09	$177.07	$177.04	$177.02	$177.00	$176.98	$176.96	$176.94	$176.91	$176.89	$176.88	$176.86	$176.84	$176.82	$176.80	$176.79	$176.77	$176.76	$176.75	$176.74	$176.72
	$177.08	TOLLED COST ($/MWH)		$177.30	$177.28	$177.25	$177.23	$177.21	$177.18	$177.16	$177.14	$177.11	$177.09	$177.07	$177.04	$177.02	$177.00	$176.98	$176.96	$176.94	$176.91	$176.89	$176.88	$176.86	$176.84	$176.82	$176.80	$176.79	$176.77	$176.76	$176.75	$176.74	$176.72
	PRODUCTION DATA:		AVERAGE	0.17730343																													
	ELECTRIC ENERGY	(MWH)	12,991	15220	15066	14913	14759	14605	14451	14298	14144	13990	13836	13683	13529	13375	13221	13068	12914	12760	12607	12453	12299	12145	11992	11838	11684	11530	11377	11223	11069	10915	10762
	TOTAL ELECTRIC	(MWH)	12,991	15220	15066	14913	14759	14605	14451	14298	14144	13990	13836	13683	13529	13375	13221	13068	12914	12760	12607	12453	12299	12145	11992	11838	11684	11530	11377	11223	11069	10915	10762
	FCP FUEL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	AVG HEAT RATE	(BTU/KWH)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	AVG OUTPUT	(KW)		1737	1720	1702	1685	1667	1650	1632	1615	1597	1580	1562	1544	1527	1509	1492	1474	1457	1439	1422	1404	1386	1369	1351	1334	1316	1299	1281	1264	1246	1229
	CAPACITY FACTOR	(%) FIRM	14.83%	17.37%	17.20%	17.02%	16.85%	16.67%	16.50%	16.32%	16.15%	15.97%	15.80%	15.62%	15.44%	15.27%	15.09%	14.92%	14.74%	14.57%	14.39%	14.22%	14.04%	13.86%	13.69%	13.51%	13.34%	13.16%	12.99%	12.81%	12.64%	12.46%	12.29%
	AMMONIA	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MAKEUP WATER	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOWER MAKEUP	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	WASTE WATER	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NOx	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	SOx	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

HDR		
LG&E - KU		
PROJECT:	221566	EW BROWN SOLAR
DATE:	2/12/2014 9:34	
FILE:	0	SHEET 2

REVENUE:	($1,000)																															
CAPACITY FIXED		$18.43	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211
ENERGY																																
	VARIABLE ENERGY		$107.63	106.17183	104.72697	103.29096	101.86401	100.44633	99.038153	97.639705	96.251218	94.872931	93.50509	92.147944	90.801751	89.466773	88.143279	86.831546	85.531855	84.244496	82.969764	81.707962	80.459401	79.224399	78.0032808	76.7963796	75.6040367	74.4266017	73.2644322	72.1178946	70.9873641	69.8732249
	FUEL		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE		$29,342	$2,319	$2,318	$2,316	$2,315	$2,313	$2,312	$2,311	$2,309	$2,308	$2,306	$2,305	$2,304	$2,302	$2,301	$2,300	$2,298	$2,297	$2,296	$2,294	$2,293	$2,292	$2,291	$2,289	$2,288	$2,287	$2,286	$2,285	$2,284	$2,282	$2,281

PRO FORMA ANALYSIS:

YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30

EXPENSES: ($1,000)

NATURAL GAS CONSUMPTION			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS ANNUAL DEMAND CHARGE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT COST ($/MWH)			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMMONIA			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CLARIFIED WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMIN WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CHEMICAL FEED			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STARTUP FUEL			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE MAINTENANCE PARTS AND LABOR			$15	$15	$16	$16	$16	$17	$17	$18	$18	$19	$19	$19	$20	$20	$21	$21	$22	$22	$23	$24	$24	$25	$25	$26	$27	$27	$28	$28	$29	$30
FIXED MAINTENANCE PARTS AND LABOR			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O&M	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MISC EXPENSES			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INSURANCES			$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
PROPERTY TAXES			$53	$51	$49	$47	$45	$44	$42	$40	$38	$36	$34	$33	$31	$29	$27	$25	$24	$22	$20	$18	$16	$15	$13	$11	$9	$7	$5	$4	$2	$0
LAND LEASE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		LEVELIZED																														
Fixed ($/MWH)	$9	$5.40	$6.08	6.0262211	5.9667384	5.9060165	5.8440162	5.7806968	5.7160157	5.6499284	5.5823887	5.5133481	5.442756	5.3705596	5.2967035	5.2211298	5.1437778	5.0645842	4.9834823	4.9004023	4.8152709	4.7280113	4.6385425	4.5467797	4.45263345	4.35600964	4.2568092	4.15492767	4.05025486	3.94267448	3.83206366	3.71829253
Variable ($/MWH)	$2	$1.45	0.98554132	1.0194922	1.0547225	1.0912862	1.12924	1.1686433	1.2095583	1.2520507	1.2961889	1.3420452	1.3896953	1.439219	1.4907	1.5442266	1.5998914	1.6577922	1.718032	1.7807192	1.8459683	1.9138999	1.9846415	2.0583277	2.13510065	2.21511074	2.29851704	2.38548796	2.47620185	2.57084779	2.66962628	2.77275013
Consumables ($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		NPV																														
TOTAL OPERATING COST		$1,196	$108	$106	$105	$103	$102	$100	$99	$98	$96	$95	$94	$92	$91	$89	$88	$87	$86	$84	$83	$82	$80	$79	$78	$77	$76	$74	$73	$72	$71	$70
UNIT COST ($/MWH)		$6.85	$7.07	$7.05	$7.02	$7.00	$6.97	$6.95	$6.93	$6.90	$6.88	$6.86	$6.83	$6.81	$6.79	$6.77	$6.75	$6.72	$6.70	$6.68	$6.66	$6.64	$6.62	$6.61	$6.59	$6.57	$6.56	$6.54	$6.53	$6.52	$6.50	$6.49
NET OPERATING INCOME		$28,146	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211
20 YR DEPRECIATION	$0	0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 YR ACCELERATED DEPRECIATION	$29,088	100%	$5,800	$9,367	$5,568	$3,341	$3,341	$1,671																								
* Note, if 30% ITC is applied, then only 85 % of the project can be app ied to this depreciation schedule and 15% is applied to 20 yr depreciation																																
AMORTIZATION	$29,088		$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242
BOOK DEPRECIATION			$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209	$1,209
TOTAL CUMULATIVE DEP/AMORT			$1,209	$2,418	$3,627	$4,836	$6,045	$7,254	$8,463	$9,672	$10,881	$12,090	$13,299	$14,508	$15,717	$16,926	$18,135	$19,344	$20,553	$21,762	$22,971	$24,180	$25,389	$26,598	$27,807	$29,016	$30,225	$31,434	$32,643	$33,852	$35,061	$36,270
NET BOOK VALUE			$35,061	$33,852	$32,643	$31,434	$30,225	$29,016	$27,807	$26,598	$25,389	$24,180	$22,971	$21,762	$20,553	$19,344	$18,135	$16,926	$15,717	$14,508	$13,299	$12,090	$10,881	$9,672	$8,463	$7,254	$6,045	$4,836	$3,627	$2,418	$1,209	$0
TOTAL NON-CASH CHARGES			$6,042	$9,609	$5,810	$3,583	$3,583	$1,914	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242	$242
UNIT COST ($/MWH)	EXPENSE		$397.00	$637.80	$389.63	$242.78	$245.33	$132.42	$16.95	$17.13	$17.32	$17.51	$17.71	$17.91	$18.12	$18.33	$18.54	$18.77	$18.99	$19.22	$19.46	$19.70	$19.95	$20.21	$20.47	$20.74	$21.02	$21.30	$21.59	$21.89	$22.20	$22.52
EARNINGS BEFORE INTEREST & TAXES (EBIT)			-$3,831	-$7,398	-$3,599	-$1,372	-$1,372	$298	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969
DEBT SERVICE:												10 YR					15 YR					20 YR					25 YR					30 YR
TOTAL PAYMENT			$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$1,179	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INTEREST PAYMENT			$610	$588	$566	$543	$519	$494	$468	$441	$413	$384	$354	$323	$291	$257	$222	$186	$148	$109	$69	$27	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRINCIPAL PAYMENTS			$569	$590	$613	$636	$660	$685	$711	$738	$766	$795	$825	$856	$888	$922	$957	$993	$1,031	$1,069	$1,110	$1,152	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TAX BASIS			($4,441)	($7,986)	($4,165)	($1,915)	($1,891)	($196)	$1,501	$1,528	$1,556	$1,585	$1,615	$1,646	$1,679	$1,712	$1,747	$1,783	$1,821	$1,860	$1,900	$1,942	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969	$1,969
INCOME TAXES																																
US	38.90%		($1,727)	($3,107)	($1,620)	($745)	($735)	($76)	$584	$594	$605	$617	$628	$640	$653	$666	$680	$694	$708	$723	$739	$755	$766	$766	$766	$766	$766	$766	$766	$766	$766	$766
GROSS RECIEPTS	0.00%		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	10.00%		($2,900)																													
CASH BASIS:																																
NET OPERATING INCOME (NOI)			$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211
		NPV																														
NET BEFORE TAX CASHFLOW		$15,410	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211	$2,211
		NPV																														
LESS TAXES		$4,177	$4,627	$3,107	$1,620	$745	$735	$76	($584)	($594)	($605)	($617)	($628)	($640)	($653)	($666)	($680)	($694)	($708)	($723)	($739)	($755)	($766)	($766)	($766)	($766)	($766)	($766)	($766)	($766)	($766)	($766)
NET AFTER TAX CASH		($19,705)	$5,660	$4,139	$2,653	$1,777	$1,768	$1,109	$449	$438	$427	$416	$404	$392	$380	$367	$353	$339	$324	$309	$293	$277	$1,445	$1,445	$1,445	$1,445	$1,445	$1,445	$1,445	$1,445	$1,445	$1,445
	NPV	($119)																														
	IRR	6.65%																														
DEBT SERVICE COVERAGE		AVERAGE																														
AFTER TAX		1.94	5.80	4.51	3.25	2.51	2.50	1.94	1.38	1.37	1.36	1.35	1.34	1.33	1.32	1.31	1.30	1.29	1.28	1.26	1.25	1.24	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
BEFORE TAX		1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
EQUITY RETURN:	100%																															
PRE-TAX			5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%
	AVG	ROIC	7.23%																													
POST-TAX			28.72%	21.01%	13.46%	9.02%	8.97%	5.63%	2.28%	2.22%	2.17%	2.11%	2.05%	1.99%	1.93%	1.86%	1.79%	1.72%	1.65%	1.57%	1.49%	1.41%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
	AVG	ROIC	6.21%																													
HDR		ROA	18.72%	15.53%	8.71%	5.44%	5.41%	3.23%	1.25%	1.22%	1.19%	1.15%	1.12%	1.09%	1.05%	1.02%	0.98%	0.94%	0.90%	0.86%	0.81%	0.77%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%	4.01%
LG&E - KU		20 YR - AVG	3.57%																													
PROJECT: 221566	EW BROWN SOLAR	40 YR - AVG	3.72%																													
DATE: 2/12/2014 9:34																																
FILE: 0																																

HDR		
LG&E - KU		
PROJECT:	221566	EW BROWN SOLAR
DATE:	2/12/2014 9:35	
FILE:		SHEET 1

PLANT DESIGN: 10 MW PV Solar - Multicrystalline High Efficiency

PLANT GROSS CAPACITY	NEW & CLEAN	10,000	KW-AC	12500 kW - DC
NET CONTRACT DEMAND		10,000	KW-AC	
HEAT RATE - GROSS HHV		0	BTU/KWH	
HEAT RATE - NET HHV		0	BTU/KWH	

CAPITAL COST CATEGORIES:	($1,000)	
HARD COSTS:		
EPC PLANT		$33,000
SOFT COSTS:		
TOTAL OWNER INDIRECTS		$2,920
OWNER CONTINGENCY		$4,950
PROJECT MANAGEMENT		$0
ENGINEERING SUPPORT		$0
FINANCE FEE	0.015	$0
AFUDC	0.0404083	$0
CONSTRUCTION MNGMT		$0
OWNER CONTINGENCY	0.1	$0
PLANT OPS		$0
INSURANCE	CONST	$0
ESCALATION ALLOWANCE		$0
SUB-TOTAL	19.26%	$7,870
TOTAL PROJECT COST		$40,870
INSTALLED POWER PLANT COST ($/KW)		$3,270 $/kW-DC
		$4,087.00

FINANCE STRUCTURE:				
DEBT		AVG DCR	1.95	
	PERCENT	$18,665	46%	
	RATE		3.73%	
	TERM	20 YR	80	
	PAYMENT - QUARTER		$332	
EQUITY				
	PERCENT	$22,205	54%	
	POST-TAX RETURN	(TARGET)	5.24%	
	EQUITY PAYMENT		$1,164	GOAL SEEK IRR=3.73% UNLEVERED
		IRR	6.71%	
		NPV	($52)	

DEPRECIATION	NEW PLANT - UTILITY	20	YR MACRS
AMORTIZATION		30	YRS
DISCOUNT RATE		6.75%	
PROJECT LIFE		30	YRS

PRO FORMA ANALYSIS:

YEAR		2015 0	2016 1	2017 2	2018 3	2019 4	2020 5	2021 6	2022 7	2023 8	2024 9	2025 10	2026 11	2027 12	2028 13	2029 14	2030 15
ESCALATORS:																	
PARTS			2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
CONSUMABLE ESC.			0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
UNIT COST DATA:																	
FUEL																	
NATURAL GAS	($/MMBTU)	$11.70	$4.96	$5.31	$5.66	$6.06	$6.53	$6.91	$7.22	$7.59	$7.93	$8.32	$8.62	$8.99	$9.38	$9.80	$10.28
NATURAL GAS ANNUAL DEMAND CHARGE		($1,000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
0 PRICING OPTIONS	MARGINAL																
$182.56 POWER — CAPITAL RECOVERY	($/MWH)		$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56
FIXED CAPACITY-DB	($/KW-MO)		$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07
FIXED CAPACITY-EQ	($/KW-MO)		$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70
$6.81 — OP COST	($/MWH)		$7.15	$7.11	$7.08	$7.05	$7.01	$6.98	$6.94	$6.91	$6.88	$6.84	$6.81	$6.77	$6.74	$6.71	$6.67
$0.00 30 YR - LEVELIZED — FUEL COST POWER	($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
61.53 $189.38 TOTAL COST	($/MWH)		$189.71	$189.68	$189.64	$189.61	$189.58	$189.54	$189.51	$189.47	$189.44	$189.41	$189.37	$189.34	$189.30	$189.27	$189.23
$189.38 TOLLED COST	($/MWH)		$189.71	$189.68	$189.64	$189.61	$189.58	$189.54	$189.51	$189.47	$189.44	$189.41	$189.37	$189.34	$189.30	$189.27	$189.23
PRODUCTION DATA:		AVERAGE	0.189711019														
ELECTRIC ENERGY	(MWH)	13,650	15992	15830	15669	15507	15346	15184	15023	14861	14700	14538	14377	14215	14053	13892	13730
TOTAL ELECTRIC	(MWH)	13,650	15992	15830	15669	15507	15346	15184	15023	14861	14700	14538	14377	14215	14053	13892	13730
FCP FUEL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG HEAT RATE	(BTU/KWH)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG OUTPUT	(KW)		1826	1807	1789	1770	1752	1733	1715	1696	1678	1660	1641	1623	1604	1586	1567
CAPACITY FACTOR	(%) FIRM	15.58%	18.26%	18.07%	17.89%	17.70%	17.52%	17.33%	17.15%	16.96%	16.78%	16.60%	16.41%	16.23%	16.04%	15.86%	15.67%
AMMONIA	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAKEUP WATER	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOWER MAKEUP	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WASTE WATER	(K-GALLONS)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	(TON)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

YEAR		2031 16	2032 17	2033 18	2034 19	2035 20	2036 21	2037 22	2038 23	2039 24	2040 25	2041 26	2042 27	2043 28	2044 29	2045 30
PARTS		2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%	2.40%
CONSUMABLE ESC.		0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
NATURAL GAS	($/MMBTU)	$10.68	$11.46	$12.23	$12.84	$13.48	$14.15	$14.85	$15.60	$16.37	$17.19	$17.90	$18.77	$19.67	$20.61	$21.59
NATURAL GAS ANNUAL DEMAND CHARGE		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPITAL RECOVERY	($/MWH)	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56	$182.56
FIXED CAPACITY-DB	($/KW-MO)	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07	$11.07
FIXED CAPACITY-EQ	($/KW-MO)	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70
OP COST	($/MWH)	$6.64	$6.60	$6.57	$6.53	$6.50	$6.47	$6.43	$6.40	$6.37	$6.34	$6.30	$6.27	$6.24	$6.21	$6.18
FUEL COST POWER	($/MWH)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL COST	($/MWH)	$189.20	$189.17	$189.13	$189.10	$189.06	$189.03	$189.00	$188.96	$188.93	$188.90	$188.87	$188.84	$188.80	$188.77	$188.74
TOLLED COST	($/MWH)	$189.20	$189.17	$189.13	$189.10	$189.06	$189.03	$189.00	$188.96	$188.93	$188.90	$188.87	$188.84	$188.80	$188.77	$188.74
ELECTRIC ENERGY	(MWH)	13569	13407	13246	13084	12923	12761	12600	12438	12277	12115	11954	11792	11630	11469	11307
TOTAL ELECTRIC	(MWH)	13569	13407	13246	13084	12923	12761	12600	12438	12277	12115	11954	11792	11630	11469	11307
FCP FUEL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	(MMBTU)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG HEAT RATE	(BTU/KWH)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AVG OUTPUT	(KW)	1549	1531	1512	1494	1475	1457	1438	1420	1401	1383	1365	1346	1328	1309	1291
CAPACITY FACTOR	(%)	15.49%	15.31%	15.12%	14.94%	14.75%	14.57%	14.38%	14.20%	14.01%	13.83%	13.65%	13.46%	13.28%	13.09%	12.91%
AMMONIA	(TON)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MAKEUP WATER	(K-GALLONS)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOWER MAKEUP	(K-GALLONS)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WASTE WATER	(K-GALLONS)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	(TON)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	(TON)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

HDR		
LG&E - KU		
PROJECT:	221566	EW BROWN SOLAR
DATE:	2/12/2014 9:35	
FILE:	0	SHEET 2

REVENUE: ($1,000)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPACITY FIXED		$20.77	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
ENERGY																	
	VARIABLE ENERGY		$114.30	112.61279	110.93793	109.27191	107.61496	105.96728	104.32911	102.70066	101.08217	99.473886	97.876045	96.288899	94.712706	93.147728	91.594234
	FUEL		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE		$32,968	$2,606	$2,605	$2,603	$2,601	$2,600	$2,598	$2,596	$2,595	$2,593	$2,591	$2,590	$2,588	$2,587	$2,585	$2,584

		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CAPACITY FIXED		$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
	VARIABLE ENERGY	90.052501	88.52281	87.005451	85.500719	84.008917	82.530356	81.065354	79.6142357	78.1773345	76.7549917	75.3475566	73.9553871	72.5788496	71.2183191	69.8741799
	FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL REVENUE		$2,582	$2,580	$2,579	$2,577	$2,576	$2,574	$2,573	$2,572	$2,570	$2,569	$2,567	$2,566	$2,565	$2,563	$2,562

PRO FORMA ANALYSIS:

YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30

EXPENSES: ($1,000)

NATURAL GAS CONSUMPTION			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS ANNUAL DEMAND CHARGE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT COST ($/MWH)			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMMONIA			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CLARIFIED WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMIN WATER			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CHEMICAL FEED			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STARTUP FUEL			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE MAINTENANCE PARTS AND LABOR			$15	$15	$16	$16	$16	$17	$17	$18	$18	$19	$19	$19	$20	$20	$21
FIXED MAINTENANCE PARTS AND LABOR			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O&M	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MISC EXPENSES			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INSURANCES			$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
PROPERTY TAXES			$59	$57	$55	$53	$51	$49	$47	$45	$43	$41	$39	$37	$35	$33	$31
LAND LEASE			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		LEVELIZED															
Fixed ($/MWH)	$10	$5.43	$6.21	6.1421807	6.075084	6.0065895	5.936653	5.8652285	5.792268	5.7177214	5.6415364	5.5636584	5.4840303	5.4025925	5.3192826	5.2340353	5.1467821
Variable ($/MWH)	$2	$1.38	0.937974521	0.9702868	1.0038167	1.0386157	1.0747376	1.1122391	1.1511794	1.1916209	1.2336288	1.2772718	1.3226222	1.3697556	1.4187519	1.469695	1.5226732
Consumables ($/MWH)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		NPV															
TOTAL OPERATING COST		$1,252	$114	$113	$111	$109	$108	$106	$104	$103	$101	$99	$98	$96	$95	$93	$92
UNIT COST ($/MWH)		$6.81	$7.15	$7.11	$7.08	$7.05	$7.01	$6.98	$6.94	$6.91	$6.88	$6.84	$6.81	$6.77	$6.74	$6.71	$6.67
NET OPERATING INCOME		$31,715	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
20 YR DEPRECIATION	$0	0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 YR ACCELERATED DEPRECIATION	$33,100	100%	$6,600	$10,659	$6,336	$3,802	$3,802	$1,902									
* Note, if 30% ITC is applied, then only 85 % of the project can be app ied to this depreciation schedule and 15% is applied to 20 yr depreciation																	
AMORTIZATION	$33,100		$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262
BOOK DEPRECIATION			$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362
TOTAL CUMULATIVE DEP/AMORT			$1,362	$2,725	$4,087	$5,449	$6,812	$8,174	$9,536	$10,899	$12,261	$13,623	$14,986	$16,348	$17,710	$19,073	$20,435
NET BOOK VALUE			$39,508	$38,145	$36,783	$35,421	$34,058	$32,696	$31,334	$29,971	$28,609	$27,247	$25,884	$24,522	$23,160	$21,797	$20,435
TOTAL NON-CASH CHARGES			$6,862	$10,921	$6,598	$4,064	$4,064	$2,164	$262	$262	$262	$262	$262	$262	$262	$262	$262
UNIT COST ($/MWH)	EXPENSE		$429.11	$689.90	$421.11	$262.07	$264.82	$142.52	$17.46	$17.65	$17.85	$18.04	$18.25	$18.45	$18.67	$18.88	$19.11
EARNINGS BEFORE INTEREST & TAXES (EBIT)			-$4,370	-$8,429	-$4,106	-$1,572	-$1,572	$328	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230
DEBT SERVICE:												10 YR					15 YR
TOTAL PAYMENT			$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328	$1,328
INTEREST PAYMENT			$687	$663	$638	$612	$585	$557	$527	$497	$466	$433	$399	$364	$327	$290	$250
PRINCIPAL PAYMENTS			$641	$665	$691	$717	$744	$772	$801	$831	$863	$895	$929	$964	$1,001	$1,039	$1,078
TAX BASIS			($5,058)	($9,092)	($4,744)	($2,184)	($2,157)	($229)	$1,702	$1,733	$1,764	$1,797	$1,831	$1,866	$1,902	$1,940	$1,979
INCOME TAXES																	
US	38.90%		($1,967)	($3,537)	($1,846)	($849)	($839)	($89)	$662	$674	$686	$699	$712	$726	$740	$755	$770
GROSS RECIEPTS	0.00%		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC	10.00%		($3,300)														
CASH BASIS:																	
NET OPERATING INCOME (NOI)			$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164
		NPV															
NET BEFORE TAX CASHFLOW		$17,364	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164	$1,164
		NPV															
LESS TAXES		$4,789	$5,267	$3,537	$1,846	$849	$839	$89	($662)	($674)	($686)	($699)	($712)	($726)	($740)	($755)	($770)
NET AFTER TAX CASH		($22,205)	$6,431	$4,700	$3,009	$2,013	$2,002	$1,253	$501	$490	$477	$465	$451	$438	$424	$409	$394
	NPV	($52)															
	IRR	6.71%															
DEBT SERVICE COVERAGE		AVERAGE															
AFTER TAX		1.95	5.84	4.54	3.27	2.52	2.51	1.94	1.38	1.37	1.36	1.35	1.34	1.33	1.32	1.31	1.30
BEFORE TAX		1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
EQUITY RETURN:	100%																
PRE-TAX			5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%	5.24%
	AVG ROIC	7.23%															
POST-TAX			28.96%	21.17%	13.55%	9.07%	9.02%	5.64%	2.26%	2.20%	2.15%	2.09%	2.03%	1.97%	1.91%	1.84%	1.77%
	AVG ROIC	6.22%															
HDR	ROA		18.91%	15.70%	8.78%	5.47%	5.44%	3.24%	1.23%	1.21%	1.18%	1.14%	1.11%	1.08%	1.04%	1.01%	0.97%
LG&E - KU	20 YR - AVG	3.59%															
PROJECT: 221566 EW BROWN SOLAR	40 YR - AVG	3.72%															
DATE: 2/12/2014 9:35																	
FILE: 0																	

NATURAL GAS CONSUMPTION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS ANNUAL DEMAND CHARGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
UNIT COST ($/MWH)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CLARIFIED WATER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMIN WATER	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CHEMICAL FEED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STARTUP FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
VARIABLE MAINTENANCE PARTS AND LABOR	$21	$22	$22	$23	$24	$24	$25	$25	$26	$27	$27	$28	$28	$29	$30
FIXED MAINTENANCE PARTS AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FIXED O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MISC EXPENSES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INSURANCES	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
PROPERTY TAXES	$29	$27	$25	$22	$20	$18	$16	$14	$12	$10	$8	$6	$4	$2	$0
LAND LEASE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fixed ($/MWH)	5.0574514	4.9659682	4.8722537	4.7762253	4.6777962	4.5768752	4.4733664	4.36716917	4.25817724	4.14627885	4.03135619	3.91328495	3.79193396	3.66716464	3.53883047
Variable ($/MWH)	1.5777795	1.6351118	1.6947734	1.7568733	1.8215262	1.8888535	1.9589833	2.03205078	2.10819921	2.18757994	2.27035323	2.35668886	2.44676674	2.54077773	2.63892434
Consumables ($/MWH)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL OPERATING COST	$90	$89	$87	$86	$84	$83	$81	$80	$78	$77	$75	$74	$73	$71	$70
UNIT COST ($/MWH)	$6.64	$6.60	$6.57	$6.53	$6.50	$6.47	$6.43	$6.40	$6.37	$6.34	$6.30	$6.27	$6.24	$6.21	$6.18
NET OPERATING INCOME	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
20 YR DEPRECIATION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMORTIZATION	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262
BOOK DEPRECIATION	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362	$1,362
TOTAL CUMULATIVE DEP/AMORT	$21,797	$23,160	$24,522	$25,884	$27,247	$28,609	$29,971	$31,334	$32,696	$34,058	$35,421	$36,783	$38,145	$39,508	$40,870
NET BOOK VALUE	$19,073	$17,710	$16,348	$14,986	$13,623	$12,261	$10,899	$9,536	$8,174	$6,812	$5,449	$4,087	$2,725	$1,362	$0
TOTAL NON-CASH CHARGES	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262	$262
UNIT COST ($/MWH)	$19.33	$19.57	$19.80	$20.05	$20.30	$20.56	$20.82	$21.09	$21.37	$21.65	$21.95	$22.25	$22.56	$22.87	$23.20
EARNINGS BEFORE INTEREST & TAXES (EBIT)	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230
DEBT SERVICE:					20 YR					25 YR					30 YR
TOTAL PAYMENT	$1,328	$1,328	$1,328	$1,328	$1,328	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
INTEREST PAYMENT	$210	$167	$123	$78	$30	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRINCIPAL PAYMENTS	$1,119	$1,161	$1,205	$1,251	$1,298	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TAX BASIS	$2,020	$2,062	$2,106	$2,152	$2,199	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230	$2,230
US	$786	$802	$819	$837	$855	$867	$867	$867	$867	$867	$867	$867	$867	$867	$867
GROSS RECIEPTS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NET OPERATING INCOME (NOI)	$1,164	$1,164	$1,164	$1,164	$1,164	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
NET BEFORE TAX CASHFLOW	$1,164	$1,164	$1,164	$1,164	$1,164	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492	$2,492
LESS TAXES	($786)	($802)	($819)	($837)	($855)	($867)	($867)	($867)	($867)	($867)	($867)	($867)	($867)	($867)	($867)
NET AFTER TAX CASH	$378	$361	$344	$326	$308	$1,625	$1,625	$1,625	$1,625	$1,625	$1,625	$1,625	$1,625	$1,625	$1,625
AFTER TAX	1.28	1.27	1.26	1.25	1.23	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
BEFORE TAX	1.88	1.88	1.88	1.88	1.88	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
PRE-TAX	5.24%	5.24%	5.24%	5.24%	5.24%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%	11.22%
POST-TAX	1.70%	1.63%	1.55%	1.47%	1.39%	7.32%	7.32%	7.32%	7.32%	7.32%	7.32%	7.32%	7.32%	7.32%	7.32%
ROA	0.93%	0.89%	0.85%	0.80%	0.76%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%

APPENDIX G

ENVIRONMENTAL REVIEW (CRITICAL ISSUES ANALYSIS)

E.W. BROWN 10 MW PV SOLAR SITING CRITICAL ISSUES ANALYSIS

Prepared for:

LG&E and Kentucky Utility Services Company
820 West Broadway
Louisville, KY 40202

Prepared by:
HDR ENGINEERING, INC. OF THE CAROLINAS
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December 2013

E.W. BROWN 10 MW PV SOLAR SITING
CRITICAL ISSUES ANALYSIS

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Section 1
Introduction

HDR Engineering, Inc. of the Carolinas (HDR) prepared a Critical Issues Analysis (CIA) for LG&E and Kentucky Utilities (LG&E/KU) potential construction of a 10 megawatt (MW) photovoltaic (PV) solar energy project in Mercer County, Kentucky (Figure 1). This effort is in support of a certificate of public convenience and necessity filing with the Kentucky Public Service Commission for permission to construct the solar facility.

The CIA identifies potential developmental constraints within a 153 acres study area based on publicly available data. In addition, this report summarizes permit requirements that may be required by federal, state, and local entities. Based on the results of a desk-top review and site visit, HDR has outlined recommendations for critical issue resource areas that will require further study prior to proceeding with project development.

1.1 Project Description

LG&E/KU is assessing the potential to construct a 10 MW PV solar facility adjacent to the existing E.W. Brown Generating Station in Mercer County, Kentucky. The final PV module design footprint would be sited within the 153 acres study area. The final PV module design footprint will be based on minimizing impacts to environmental resources, and suitable topography for the PV units. The preliminary PV module design footprint requires approximately 56 acres and approximately 80 acres within the fenced PV boundary area (Figure 1).

1.2 Project Location

The study area is located entirely on LG&E/KU land within the jurisdiction of Mercer County. It is located to the south of the existing E.W. Brown Generating Station on a property formerly known as the Hardin Farm Estate (TMS # 079.00-00014.00). Past land uses of the study area were agricultural. The surrounding land use is mixed with agricultural, residential, open space and industrial uses represented within a quarter mile of the study area.

The study area is located approximately 8 miles east of the City of Harrodsburg and lies west and adjacent to the Herrington Lake. Adjacent land owners include; residential lakeside parcels, residential farmland parcels, the USACE (Herrington Lake) and Kentucky Utilities Company (E.W. Brown Generation Station).

Section 2
Environmental Characteristics

HDR conducted an advanced desktop review and site visit to identify the existing land use, infrastructure, soils, geologic, hydrologic resources, biological resources, and cultural resources within the study area and immediate vicinity. HDR collected and utilized all publicly available information through database research and Geographic Information System (GIS) mapping. The following sources were consulted as a part of this analysis in addition to literature cited in Section 5:

- ESRI ArcGIS online aerial imagery, streets, and basemap information
- Federally Protected Species List U.S Fish and Wildlife Service (USFWS) Information, Planning, and Conservation System (IPAC) web site, http://ecos.fws.gov/ipac/
- Kentucky State Nature Preserve Commission web site http://naturepreserves.ky.gov/naturepreserves/Pages/preserves.aspx;
- Kentucky Heritage Council (KHC) http://heritage.ky.gov/natreg/
- National Register of Historic Places http://nrhp.focus.nps.gov
- Kentucky Geography Network, http://kygisserver.ky.gov/geoportal/catalog/main/home.page
- National Hydrography Dataset (NHD) (U.S. Geological Survey, http://nhd.usgs.gov/
- National Wetland Inventory (NWI), USFWS, http://www.fws.gov/wetlands
- Federal Emergency Management Agency (FEMA) floodplain GIS shape files
- Kentucky Soils Data Viewer http://kygeonet.ky.gov/kysoils/
- National Hydric Soils List (Natural Resources Conservation Service, http://soils.usda.gov/use/hydric
- USGS topographic maps

HDR used all readily available data to produce environmental maps and to identify and analyze potential environmental constraints within the study area. Additionally, permit requirements were assessed based on publicly available information and through direct communication with federal, state, and local authorities. All findings are summarized in this document and in the following sections, 2.0 thru 4.0.

2.1 Hydrology

The following agencies have regulatory authority over impacts to surface waters and wetlands in Kentucky:

- Federal: the U.S. Army Corps of Engineers (USACE) and the U.S. Environmental Protection Agency (EPA)
- State: Kentucky Division of Water (DOW)

WETLANDS/JURISDICTIONAL WATERS

The USACE, through Section 404 of the Clean Water Act (CWA), has regulatory authority over wetlands and waters of the United States that support an Ordinary High Water Mark (OHWM) and discharge into Traditional Navigable Waters (TNW). This authority empowers the USACE to identify wetland/upland boundaries and to regulate alterations of jurisdictional waters. These boundaries are established in accordance with the methodology in the 1987 Corps of Engineers Wetlands Delineation Manual with technical guidance from the Eastern Mountains and Piedmont Regional Supplement and Rapanos guidance forms.

The USACE (Federal Register 1982) and Environmental Protection Agency (EPA) (Federal Register 1980) jointly define wetlands as: “Those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions” (USACE 1987). Wetlands generally include swamp marshes, bogs, and similar areas. The ecological parameters for designating wetlands include hydrophytic vegetation, hydric soils, and hydrological conditions that involve a temporary or permanent source of water to cause soil saturation.

The USFWS’s National Wetland Inventory (NWI) data was used to evaluate potential jurisdictional wetlands within the study area. NWI data was field checked on November 12, 2013, and Figure 1 provides a representation of the types and extents of jurisdictional wetlands that may be present. The NWI identified three areas that represent approximately 2 acres of potential wetlands within the study area. Boundaries were not fully delineated in the field but were found to be consistent with those illustrated in the NWI and included two additional areas. Wetlands types included palustrine emergent (PEM), and forested (PFO) wetlands. Figure 1 shows the estimated wetland boundaries obtained during the site visit.

The three NWI identified areas consisted of two PEM wetlands (wetland 1 and 5), and one agricultural pond (may be spring fed) with fringe PEM wetlands (pond 1, wetland 4). Additionally, two other wetland areas were identified as PFO wetland areas (wetland 2, and 3). Both wetland 2 and 3 are hydrologically fed by springs/seeps. In Appendix B, photographs 4 -9 document the conditions of each feature.

SURFACE WATER

The USGS National Hydrography Dataset (NHD) was used to identify potential jurisdictional streams within the study area. The NHD is the surface-water component of *The National Map* containing a comprehensive set of digital spatial data that represents the surface water of the U.S. using common features such as lakes, ponds, streams, rivers, canals, stream gages, and dams.

Along with the NWI database, the NHD waterbody database also identifies approximately 2 acres of surface waters within the study area. The NHD flowlines identified 0.65 miles (3,432 LF) of stream length located within the study area. The stream begins at the railroad boundary on the west side of the study area and continues southeast through a sloping forested area and outlets in Herrington Lake.

HDR's site visit confirmed three jurisdictional streams are present within the study area. Stream 1 is an unnamed tributary (UT) to Dix River (Herrington Lake) and streams 2 and 3 feed into stream 1. Streams 1, 2 and 3 are approximately 3,000, 345, and 195 linear feet in length, respectively. The network of identified streams is larger and slightly deviates from NWI predictions. Figure 1 depicts the estimated stream locations on the site. In Appendix B, photographs 10 – 13 document the conditions of each feature.

FLOODPLAIN

The study area does not fall within a Federal Emergency Management Agency (FEMA) designated Special Flood Hazard Area (SFHA) based on the Flood Insurance Rate Map (FIRM) numbered 21167C0165C, Panel 165 of 275, with effective date of September 17, 2008. The study area does abut the special flood hazard area which is part of the 100-year flood area of Herrington Lake. It is not anticipated the proposed project would not have any impacts to FEMA-regulated floodplains.

CLEAN WATER ACT SECTION 404/401 PERMITS

In accordance with provisions of the Section 404/401 of the Clean Water Act (CWA) (33 USC 1344) permits are required from the USACE and the KDOW for discharges or fill into waters of the U.S. KDOW has a joint application process with the Louisville USACE district, which manages the Section 404 regulatory program in Kentucky. KDOW will place general conditions on all 401 certifications as well as specific conditions based on a case-by-case basis. Proposed projects are to be designed to minimize, avoid, and mitigate for indirect and direct impacts to onsite waters of the U.S. Under the CWA Section 404b (1) Guidelines (40 CFR 230) and USACE regulations (33 CFR 320.4(r)), the USACE is obligated to require mitigation for any unavoidable impacts to waters of the U.S. as a condition of permit approval.

Nationwide permits (NWPs) are commonly issued for projects that have minimal impacts to the waters of the U.S. and generally authorize wetland fills of less than half an acre (1/2 acre) and, or non-tidal stream impacts less than 300 linear feet. The USACE has 45 days to issue a NWP once the application has been received and determined to be complete. NWP 51 is a new NWP covering land based renewable energy general facilities including facility construction, expansion or medication and would be applicable if the proposed project has minimal impacts.

Individual permits (IPs) are required for projects that have greater impacts to waters of the U.S. and require a more rigorous coordination process including a public notice and public review period. An IP typically requires 120 days to process from the time a complete application is received by the USACE. This type of permit is not anticipated.

RECOMMENDATIONS

HDR's site visit verified the presence of wetlands and streams within the study area. Based on the preliminary PV module design, jurisdictional waters will be avoided.

HDR recommends a Professional Wetland Scientist (PWS) conduct a wetland delineation within the study area boundary and submit a request for a preliminary Jurisdictional Determination (JD) package to the USACE's Louisville District to verify the presence/absence and limits of jurisdictional waters. An approved JD verification from the USACE would be beneficial in the planning process and in determining that the proposed project will not trigger a Section 404/401 application. In the event a 404/401 permit is necessary, a permit application including a compensatory mitigation plan would be required by the USACE. Mitigation ratios for potentially impacted jurisdictional waters would be determined in consultation with the USACE per the Louisville District's mitigation guidelines.

HDR recommends that a detailed hydrologic study be prepared to identify any specific hydrological constraints within the study area. These studies should detail existing groundwater depth and water quality including an impacts analysis for the proposed project.

2.2 Geology and Soils

TOPOGRAPHY

The USGS Wilmore Topographic Quadrangle, and the Kentucky USGS 10 meter digital elevation model indicates elevations on site are sloping and moderately steep ranging from approximately 930 to 760 feet above mean sea level (amsl).

GEOLOGY

The study area is located within the Lexington Limestone and High Bridge Group geologic units (KGS 2002) and is within the Inner Bluegrass of the Interior Plateau ecoregion of Kentucky. The Lexington limestone is the major rock unit in the Inner Bluegrass region of east-central Kentucky. The Lexington limestone is mostly fossiliferous limestone with minor amounts of shale. The High Bridge Group is the oldest stratisgraphic unit exposed in Kentucky and is mostly composed of fossiliferous micrite and minor dolomite that was deposited in shallow lagoons and on tidal flats. Limestone and dolomite can be susceptible to sinkholes due to the solubility of limestone in water and weak acid solutions. Sinkholes have been located on the E.W. Brown Facility Site and similar area may exist on the study area.

SOILS

A soil survey for Mercer County was last published in 1930 and soil data is based on the Natural Resource Conservation Service (NRCS) web soil survey data. There are 8 distinct soil mapping units located within the study area. Soils types are described in Table 1 and shown in Figure 1.

FARMLAND

Soils within the study area met one or more criteria to be considered a NRCS Farmland soil. According to the recent aerial imagery, and communications with LG&E/KU staff, the study area was used for agriculture purposes in the past but is currently owned by KU and is planned to accommodate this proposed solar facility.

TABLE 1
SOILS TYPES IN THE STUDY AREA

Soil Series	Mapping Unit	Farmland Rating	Hydric Status	Description
Chenault gravelly silt loam	CmB/CmC	**Prime farmland** / Farmland of statewide importance	Not Hydric	The Chenault series consists of deep, well drained, soils on ridge tops and side slopes on old high terraces. Slopes range from 6 to 12%.
Fairmount-rock outcrop complex	FaD/FaF	Not prime farmland	Not Hydric	The Fairmount series consists of shallow, well drained, slowly permeable soils that formed in limestone residuum interbedded with this layers of calcareous shales. Slopes range from 0 to 30%.
McAfee silt loam	McC/McD	**Farmland of statewide importance** / Not prime farmland	Not Hydric	The McAfee series consists of moderately deep, well drained soils that formed in residuum weathered from phosphatic limestone. Slopes range from 6 to 20%.
McAfee-rock outcrop complex	MeD	Not prime farmland	Not Hydric	The McAfee series consists of moderately deep, well drained soils that formed in residuum weathered from phosphatic limestone. Slopes range from 12 to 20%.
Bluegrass-Maury silt loams	uBlmB	**Prime farmland**	Not Hydric	The Bluegrass and Maury series consists of very deep, well drained, moderately permeable soils that formed in silty material over residuum weathered from phosphatic limestone. Slopes range from 2 to 6%.

RECOMMENDATIONS

Evidence from the onsite field visit revealed sinkholes and springs exist within the study area. HDR recommends further geologic and geotechnical studies be conducted to identify the physical characteristics of the existing underlying geology and possible building constraints for the proposed project. The proposed PV module design will geographically avoid the visually identified sinkholes and springs but a complete geologic and geotechnical studies will be useful if changes in the PV module design occur.

2.3 Biological Resources

FEDERAL REGULATIONS

Endangered Species Act (16 U.S.C. 1531-1544, 87 Stat. 884)

Under the provisions of the Endangered Species Act (ESA) of 1973 as amended, any action to adversely affect a species classified as federally protected is subject to review by the USFWS. Plants and animals with Federal classifications of Threatened or Endangered are protected under the provisions of Sections 7 and 9 of the ESA. HDR obtained an updated List of Federally Threatened and Endangered Species by County from the USFWS's Information, Planning, and Conservation System (IPAC) website http://ecos.fws.gov/ipac/ on November 6, 2013 (Table 2).

Onsite species habitat and individual species surveys and completion of a Biological Survey would be required pursuant to Section 7 or 9 consultations. Specifically for the Indiana bat, a conservation memorandum of agreement (MOA) dated 4/25/2011 is in place between LG&E/KU and USFWS. This MOA includes a final biological opinion and descriptions of work practices and protocol that must be followed for the protection of the Indiana bat. Vegetation clearing practices in the MOA should be followed closely as the proposed project will require vegetation clearing.

TABLE 2
FEDERALLY PROTECTED SPECIES IDENTIFIED IN MERCER COUNTY, KENTUCKY

Common Name	Scientific Name	Status	Habitat	Habitat Present
Clams				
Clubshell	*Pleurobema clava*	Endangered	This freshwater mussel is found in clean, loose sand and gravel in small to medium rivers. It will bury itself in the bottom substrate to depths of 4 inches	No suitable habitat
Fanshell	*Cyprogenia stegaria*	Endangered	This freshwater mussel is found in a variety of substrates including sand, gravel, cobble and mixed materials in large rivers.	No suitable habitat
Northern riffleshell	*Epioblasma torulosa rangiana*	Endangered	This freshwater mussel is found in a variety of substrates including sand, gravel, cobble and mixed materials in swift flowing riffles and runs of smaller streams.	No suitable habitat
Ring pink	*Obovaria refusa*	Endangered	This freshwater mussel is found in shallow water over silt-free sand and gravel bottoms of large rivers.	No suitable habitat
FLOWERING PLANTS				
Running Buffalo clover	*Trifolium stoloniferum*	Endangered	This perennial herb requires periodic disturbance and a somewhat open habitat to flourish. It is typically found in partially shaded woodlots, mowed areas and along streams and trails	Yes
Short's bladderpod	*Physaria globosa*	Proposed Endangered	This small plant covered with dense hairs prefers dry limestone cliffs, barrens, cedar glades, steep wooded slopes, and talus areas. Some have been found in areas of deeper soil and roadsides. The survey window is May - June (late spring –early summer).	No
Mammals				
Gray bat	*Myotis grisescens*	Endangered	This bat lives in caves year-round. In the winter gray	No

Common Name	Scientific Name	Status	Habitat	Habitat Present
			bats hibernate in deep vertical caves. In the summer, they roost in caves scattered along rivers. These caves are in limestone karst areas. They do not use houses or barns.	
Indiana bat	*Myotis sodalis*	Endangered	This bat hibernates during the winter in caves, or occasionally, in abandoned mines. During the summer they roost under the peeling bark of dead and dying trees. The summer habitat survey window is May 15 – August 15 .	Yes

Migratory Bird Treaty Act (16 U.S.C. 703)

Passed in 1918, the Migratory Bird Treaty Act (MBTA) is a statue for prohibit the kill or transport of native migratory birds, or any part, nest, or egg of any such bird unless allowed by another regulation adopted in accordance with the MBTA. The prohibition applies to birds in the international conventions between the U.S. and Great Britain (for Canada), the U.S. and Mexico, the U.S. and Japan, and the U.S. and Russia.

Bald & Golden Eagle Protection Act (16 U.S.C. 668)

This law, originally passed in 1940, provides the protection of the bald eagle and the golden eagle (as amended in 1962) by prohibiting the take, possession, sale, purchase , barter, offer to sell, purchase or barter, transport, export or import, of any bald or golden eagle, alive or dead, including any part, nest or egg, unless allowed by permit. "Take" includes pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb.

HDR environmental professionals conducted a site visit on November 12, 2013 to identify potential habitat for federally protected species within the study area. Figure 1 and photographs located in Appendix B detail the existing site conditions. The site visit revealed the following vegetative community types:

PASTURE/HAY FIELDS

Agricultural fields have recently been mowed and maintained by KU and represent the majority of the study area. These areas are characterized by planted agricultural grasses and native herbs.

FORESTED RESOURCES

Deciduous forested areas are located throughout the study area along the streams, railroad right of way edge and fence edges. Noted dominant overstory species include; black walnut (*Juglans nigra*), white ash

(*Fraxinus americana*), black cherry (*Prunus serotina*), American sycamore (*Platanus occidentalis*), Eastern red cedar (*Juniperus virginiana*), oak species (*Quercus* spp.), honey locust (*Gleditsia triacanthos*), hackberry (*Celtis occidentalis*), and osage orange (*Maclura pomifera*). Flowering dogwood (*Cornus florida*) and American holly (*Ilex opaca*) were a major component of the forested understory. Wetlands were noticed within some of these areas and are seasonally or temporarily flooded. The edge/transition areas with the maintained pasture provides marginal habitat for Running Buffalo clover. Some tree snags were noted in the areas of wetland 3 and areas along the railroad right of way which could be potential roosting cavities for the Indiana bat.

RECOMMENDATIONS

HDR recommends a protected species survey for Running Buffalo clover, and following MOA protocols for the Indiana bat within identified suitable habitat of the study area. Surveys should be conducting during each species optimal survey window. Prior to conducting the protected species survey, HDR recommends completion of a Biological Survey (following MOA standards for the Indiana bat) and informal consultation with USFWS to comment on the extent of the survey and survey methodologies.

2.4 Cultural and Archaeological Resources

The proposed project is subject to compliance with Section 106 of the National Historic Preservation Act of 1966, as amended, and implemented by the Advisory Council on Historic Preservation's Regulation for Compliance with Section 106, codified at 36 CFR Part 800 and reviewed by the Kentucky Heritage Council, Kentucky's State Historic Preservation Office. Section 106 requires federal agencies to take into account the effect of their undertakings (federally-funded, licensed, or permitted) on properties included in or eligible for inclusion in the National Register of Historic Places and to afford the Advisory Council a reasonable opportunity to comment on such undertakings.

HDR conducted a brief site overview of the structures present within the study area. Most structures appear to be older than 50 years of age and photographs 14-17 and Figure 1 describe them and their locations. Home site 1 (no photograph) includes a garage and other surrounding small buildings and was recently inhabited before the recent sale of the property. This is not anticipated to be a historic structure. Farm buildings 1 - 8 were noted on site and visually appear to be over 50 years of age. Currently, the PV module design footprint abuts farm building 8 and should be considered a risk. Other notable structures include; a concrete spring (photograph 17) located within wetland 3 and a stone spring house (photograph 6) located within wetland 2. Notable signs of graveyards were not discovered during the site visit but could exist within the study area.

RECOMMENDATIONS

HDR recommends an architectural and archaeological resources study including a literature search, records search, and field survey be conducted for the study area to identify any possible constraints. A cultural record's search can be accomplished by a review of site inventories at the Kentucky Heritage Council and the Kentucky Office of State Archaeology in Frankfort or requesting a preliminary site check online for a cost of $40. This initial review followed by a comprehensive report should be submitted for environmental review to Kentucky's KHC/SHPO for Section 106 consultation.

2.5 Hazardous Materials

The site historically has been in agricultural production. Pesticides potentially have been applied and stored within the study area.

RECOMMENDATIONS

HDR recommends a Phase I Environmental Site Assessment (ESA) be completed within the study area in order to locate and avoid hazardous and/or potential hazardous sites. A Phase I ESA is often requested by an insurance provider or financer of a project in order to identify actual or potential environmental contamination liabilities. The Phase I ESA should include a records review of federal, state, local, and tribal records that indicate hazardous material sites listed within or in close proximately to a site. Phase I ESA's also typically include site reconnaissance that visually identifies potential areas of concern and interviews with anyone who may have information regarding the existing and historical conditions of the site.

2.6 NEPA Requirements

NATIONAL ENVIRONMENTAL POLICY ACT

The National Environmental Policy Act (NEPA) establishes national environmental policy and goals for the protection, maintenance, and enhancement of the environment and provides a process for implementing these goals with federal agencies. The Act establishes the agencies responsible for handling pollution emergencies, violations of laws or regulations, contamination events, or related environmental problems.

The Kentucky Energy and Environment Cabinet serves as the state clearinghouse for environmental reviews required by NEPA. Based on HDR's current knowledge of the proposed project, this project would trigger the Kentucky Public Service Commission to request a certificate of public convenience and necessity from LG&E/KU. A required component of this submittal is a cumulative environmental assessment that specifically addresses air, water, and waste pollutants and water withdrawal of the proposed project.

RECOMMENDATIONS

HDR recommends consultation and coordination with Mercer County and various State/Federal agencies. Since this project may require state or federal permits/authorizations, it is anticipated the project will require coordination to determine specific action necessary to comply with state regulations. The following technical reports may be required:

- Geology/soils;
- Surface/groundwater hydrology;
- Wetlands/floodplain;
- Flora/fauna;
- Archaeology/Architecture/Historic;
- Cumulative environmental assessment for proposed project (KRS 224.10-280 requirements)

Section 3
Summary of Recommendations

HDR recommends consultation and coordination with the applicable jurisdictions and regulatory agencies early in project development to better understand the jurisdiction and agency expectations for technical reports that will be necessary for their review. Table 3 provides a summary of recommendations identified in the preceding sections.

TABLE 3
SUMMARY OF RECOMMENDATIONS

Recommendation	Description
Agency Coordination	HDR recommends that LG&E/KU conduct scoping with local, state, and federal agencies to determine concerns and confirm the required permits/certifications outlined herein. LG&E/KU will need to coordinate closely with the Kentucky Public Service Commission to satisfy requirements of the certificate of public convenience which includes a cumulative environmental assessment.
Preparation of Technical Studies	HDR recommends preparations of the following technical reports: • Hazardous Materials (Phase I env. site assessment) • Jurisdictional waters delineation • Geotechnical studies • Flora/fauna (i.e. State/Federal Listed Species Survey) • Archaeology/Architecture/Historic Survey

Jurisdictional Waters Delineation (expanded)	Identify and delineate jurisdictional waters of the U.S. pursuant to Section 404 of the CWA and recent Rapanos guidelines within the study area. Submit a preliminary JD package to the USACE even if no impacts to water resource occur.
Rare plant and mammal survey (expanded)	Conduct rare plant and mammal survey for Running buffalo clover and Indiana bat and other state listed species within its preferred habitat during each species optimal survey window.
Environmental Stewardship Program	LG&E and KU could add this project to the KY EXCEL Program through the Kentucky Division of Compliance Assistance. The project can be showcased as an alternative energy project and would be reported to the state. An application and annual reports are required.

Section 4
Permits and Approvals

The federal, state, and local permits or approvals that have been identified as potentially applicable for the construction and operation of the project are included in Table 4. The actual range of required permits cannot be identified until the PV module design footprint is finalized.

TABLE 4

EW BROWN 10 MW PV SOLAR MODULE PRELIMINARY PERMIT AND APPROVALS MATRIX

Regulation	Implementing Agency	Outcome	Trigger	Timeline and Fees	Website
Federal Permits					
Endangered Species Act 16 USC 1531-1544, 87 Stat. 884	United States Fish and Wildlife Service (USFWS)	Section 7 or 10; consultation and incidental take authorization	Activity that may affect federally listed species. Section 7 or 10 consultation will address entire project and incidental take as part of the project. Section requires federal nexus.	Prior to ground disturbing activities Section 7: 135 days from the time consultation is initiated to the time a biological opinion is delivered; agencies can agree to modify; **no fee** Section 10: No mandated review timeframes	http://fws.gov
Clean Water Act Section 404 33 USC 1344	Army Corps of Engineers (USACE)	Section 404 Permit; Also see State 401 requirements (joint permit)	Presence of waters of the U. S. Required for activities that would result in a discharge of dredged or fill material into waters of the United States.	Individual permits typically require a 30 day public notice period. Nationwide permits will take to 45 days to approve; mitigation may be required; **no application fee**	http://www.usace.army.mil
Kentucky Heritage Council (KHC), State Historic Preservation Office (SHPO) and National Preservation Act (NHPA) 36 CFR Part 800	KHC, SHPO and NHPA	Concurrence/Project Modification (Section 106 Compliance)	Federal actions that would affect properties protected by the NHPA. Applicable if there is a federal nexus (e.g., CWA 404 Permit).	SHPO must respond to original request for concurrence within 30 days. **No fee**. $40 initial site review fee, or free access to paper files in Frankfort.	http://heritage.ky.gov/siteprotect/

Regulation	Implementing Agency	Outcome	Trigger	Timeline and Fees	Website
Executive Orders					
The Bald and Golden Eagle Protection Act 16 USC 668-668c	USFWS	Review proposed action and address effects	Actions that could affect Bald and Golden Eagles	No timeframe and no fee.	http://www.fws.gov/midwest/Eagle/guidelines/bgepa.html
Migratory Birds (MBTA) (13186)	USFWS	Review Proposed action and address affects	Actions that could affect migratory birds (complements MBTA).	No timeframe and no fee	http://www.fws.gov/laws/lawsdigest/migtrea.html
State Permits/Compliance					
KRS 224.10-280	Kentucky Public Services Commission	Certificate of Public Convenience and Necessity that includes a cumulative environmental assessment component	Proposed construction of a facility for generation of electricity	Request meeting with Commissioners, submit Certificate.	http://psc.ky.gov/Home/UtilForms
Kentucky Energy and Environment Cabinet. Department for Environmental Protection; Clean Water Act, National Pollutant Discharge Elimination System (NPDES) Act	Kentucky Water Quality Certification Program	Section 401 Certification (NWP)(Combined Application with USACE 404 application) General Certification – NWP #51 (Land-based Renewable Energy Generation Facilities)	Proposed construction in or along a stream that could obstruct flood flows or adversely impact water quality.	Prior to construction activities. County Floodplain Coordinator must sign off on the application. No application fee but fees if stream impacts.	http://dep.ky.gov/formslibrary/Documents/WQCApplicationAmended1209.pdf NWP #51 http://water.ky.gov/permitting/Nationwide%20Permits%20Conditions/2012%20NW%2051.pdf
	Kentucky Division of Water, Wastewater Discharge)	Section 402 Notice of Intent General Permit (Construction)	Proposed construction within the State and disturbance of 1 acre of land or more.	NOI must be submitted at least 7 days prior to commencement of construction if submitted electronically or 30 days if submitted via paper. Fee based on individual permit or general permit status.	https://dep.gateway.ky.gov/eForms/default.aspx?FormID=7&S_ID=f356a5e1-df0a-4914-aad0-d0064e2e97f7
KRS 224.10-100	Kentucky Division of Air Quality	Compliance with Kentucky Fugitive Emission Regulations	During construction, any dust that is not emitted from a definable point.	No filing or paperwork required.	http://www.lrc.ky.gov/kar/401/063/010.htm

Regulation	Implementing Agency	Outcome	Trigger	Timeline and Fees	Website
Local Jurisdiction					
Mercer County / City of Harrodsburg Zoning Ordinances (revised 2/12/2007)	Mercer County	Building Permit	Any building or structure erected, moved or constructed is subject to review by the Greater Harrodsburg/Mercer County Planning and Zoning Commission	General timeframe is 10 days from time of the application submittal. Building Inspector, 859-734-3375	http://www.mercercounty.ky.gov/NR/rdonlyres/5D62DBF3-F3E3-4898-B5A9-ABD37D2DD337/0/CityofHarrodsburgZoningOrdinance.pdf

Section 5
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APPENDICES

APPENDIX A
FIGURES

EW Brown 10MW PV Solar Siting

Figure 1

HDR
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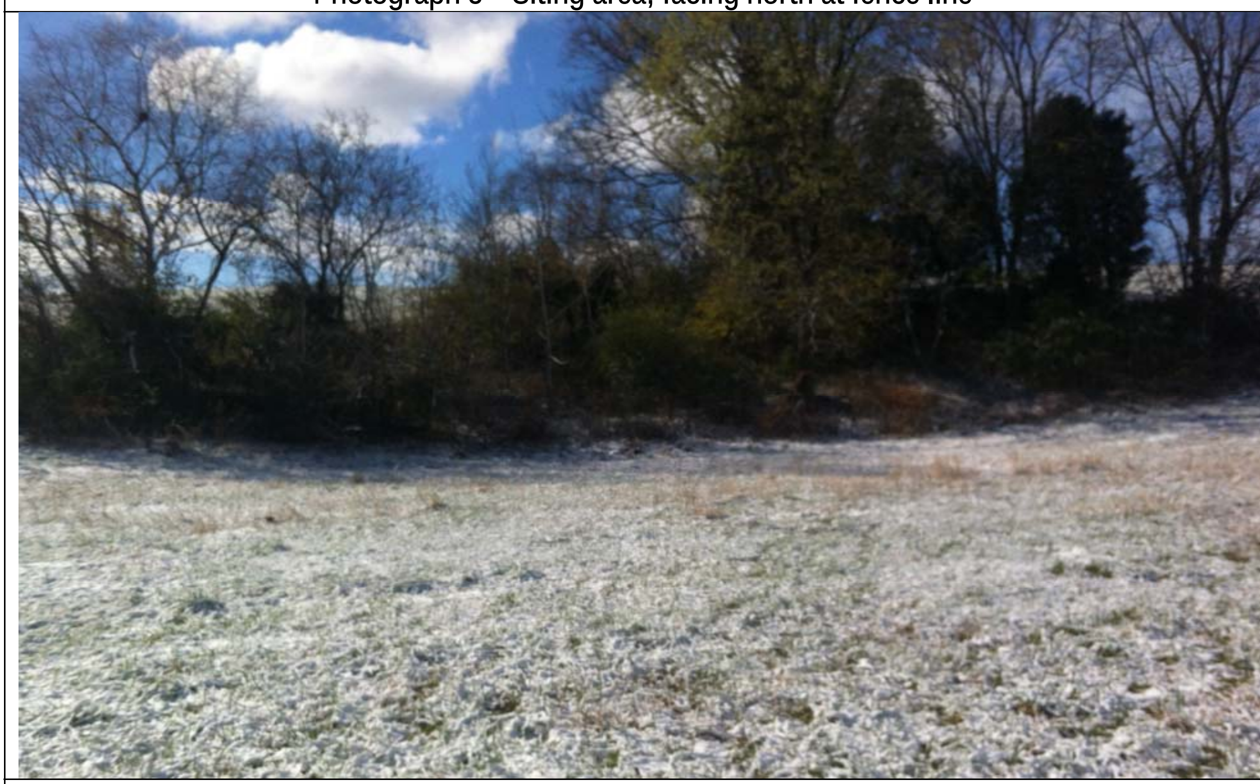
APPENDIX B
PHOTOGRAPHS

Photograph 1 – Siting area; facing west from farm road

Photograph 2 – Siting area; facing north

Photograph 3 – Siting area; facing north at fence line

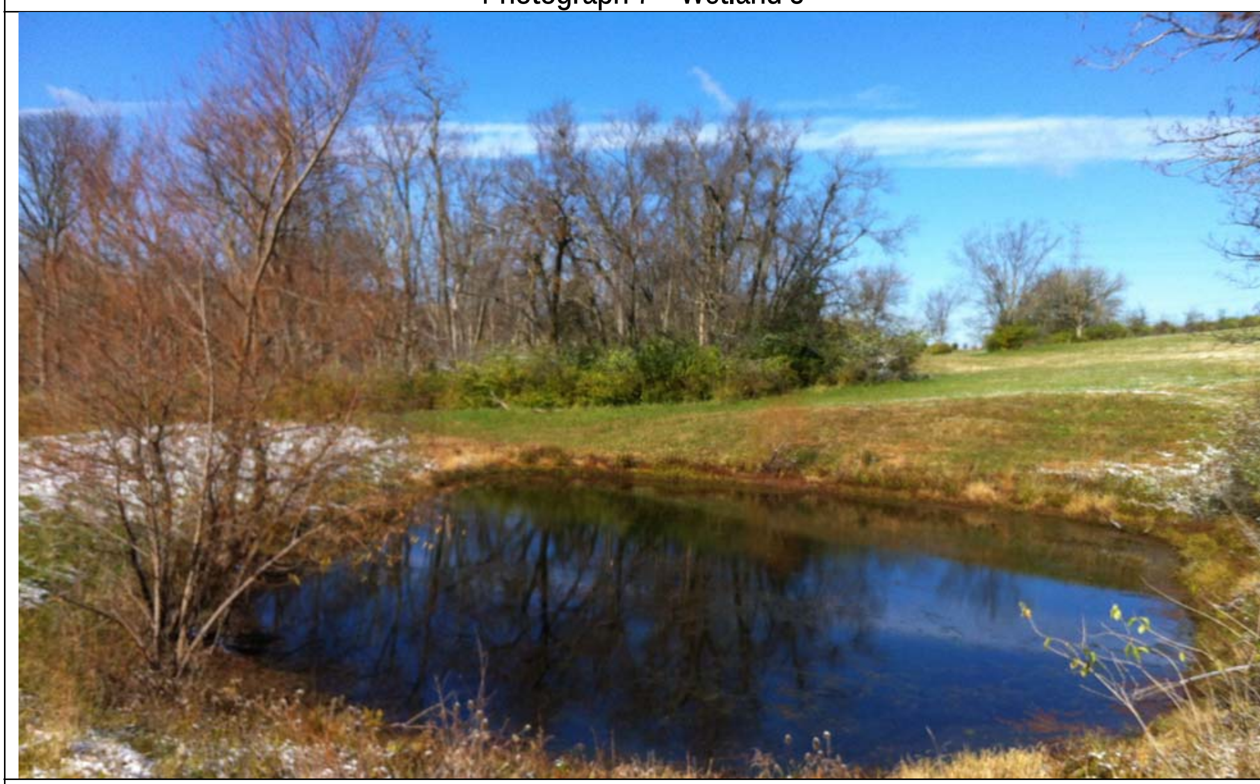


Photograph 4 – Wetland 1

Photograph 5 – Wetland 2; facing towards spring house

Photograph 6 – Stone spring house at wetland 2

Photograph 7 – Wetland 3



Photograph 8 – Wetland 4 / Pond 1

Photograph 9 – Wetland 5

Photograph 10 – Stream 1 (lower reach); facing north inside forested portion of stream

Photograph 11 – Stream 2 (upper reach); facing north at wetland 2

Photograph 12 – Stream 3

Photograph 13 – Stream 3; looking towards wetland 2

Photograph 14 – farm buildings 2, 3, and 4

Photograph 15 – farm buildings 5, 6 and 7

Photograph 16 – farm buildings (5-7) on left and home site to the right

Photograph 17 – concrete spring structure at stream 1 / wetland 3

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 138

Witness: David S. Sinclair

Q-138. Reference Mr. Sinclair's direct testimony, page 31, explain why the potential for lower future natural gas prices reduces the cost advantage of the [redacted] over NGCC alternatives given the fact that lower gas prices reduce the fuel cost advantage arising from the higher efficiency of NGCC when compared to SCCT resources.

A-138. The Resource Assessment evaluates the dispatch of the entire fleet (coal and natural gas) to meet customers' energy needs. In the Low natural gas price cases referenced on page 31, lines 19-22 of Mr. Sinclair's testimony, natural gas prices are low enough that the Green River NGCC is displacing coal-fired generation whereas this is not the case with the higher heat rate [redacted]. Therefore, the Green River NGCC is able to able to reduce customers' future energy costs in the Low natural gas price cases. Natural gas prices would need to be even lower before energy from [redacted] would displace coal-fired generation. Furthermore, [redacted] is less efficient than many of the Companies existing SCCT resources which further reduces the opportunity for it to reduce customers' energy costs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 139

Witness: John N. Voyles, Jr.

Q-139. Provide a detailed capital cost estimate for the Green River NGCC facility including transmission, gas pipeline and plant costs, along with construction interest costs.

A-139. See the Companies' response to PSC 1-30 for the detailed capital cost of the NGCC facility. The electric transmission costs are provided in the Companies' response to Question No. 179.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 140

Witness: John N. Voyles, Jr.

Q-140. Provide the status of the analysis of electric transmission system upgrades required for the Green River NGCC project along with details supporting the estimated transmission costs included for the project in the Phase 1 and Phase 2 analysis of the project.

A-140. The study requested of the Companies' ITO, as required under the Companies' OATT, is currently expected to start March 31, 2014 and be completed approximately in July 2014.

Transmission system upgrade costs were not considered in the Phase 1 screening analysis (only the cost of firm transmission service was considered where applicable). See the response to AG 1-179.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 141

Witness: David S. Sinclair

Q-141. Reference Exhibit DSS-1, page 21, explain why the Companies believe it was reasonable or realistic to assume no access to market energy purchases or off-system sales in the Phase 2 modeling of long-term resource alternatives.

A-141. See Exhibit DSS-1 at page 14.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 142

Witness: David S. Sinclair

Q-142. Reference Exhibit DSS-1, page 24, provide workpapers supporting the costs of the [redacted] and Green River projects presented in Table 18 and explain whether both projects reflect 785 MW NGCC units.

A-142. The workpapers supporting the cost of the [redacted] and Green River NCCC were provided in the response to PSC 1-22 (see 03_Deliverables\20131001_ResourceAssessment\Support\20131001_MSF_ERORAvsSBComparison_0073_D02.xlsx). Both projects reflect 785 MW NGCC units.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 143

Witness: David S. Sinclair

Q-143. Reference Exhibit DSS-1, page 24, explain why the [redacted] facility has transmission networking costs while the Green River project does not have such costs as presented in Table 18.

A-143. As proposed, the [redacted] facility would have been connected to the Companies' transmission system via a single radial transmission line. For reliability, the Green River NGCC, as well as all of the Companies' other generating units, are connected to the Companies' transmission grid via multiple transmission lines. The networking cost is the cost to connect the [redacted] facility to the Companies' transmission system via multiple transmission lines so that both projects would have a similar level of reliability.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 144

Witness: David S. Sinclair

Q-144. Reference Exhibit DSS-1, page 24, explain why the [redacted] NGCC proposal was not evaluated in the Phase 2 Strategist analysis in order to identify potential operating cost benefits arising from owning a NGCC that is somewhat larger than the proposed Green River NGCC facility.

A-144. See Exhibit DSS-1 at page 24. Because the Companies can build the same 785 MW unit at the Green River site, the most direct approach for evaluating this proposal was to compare the capital and firm gas transportation costs for the [redacted] site to the same costs for the Green River site. The comparison in Table 18 demonstrates that the Green River site is favorable to the [redacted] site, regardless of unit size.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 145

Witness: David S. Sinclair

Q-145. Provide analysis of the [redacted] proposal paired with short-term PPAs for each of the 12 scenarios evaluated consistent with the analysis presented in Table 23 on page 24 of Exhibit DSS-1.

A-145. See the response to Question No. 144. This analysis was not performed and is not necessary. Regardless of unit size, the Green River site is favorable to the [redacted] site.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 146

Witness: David S. Sinclair

Q-146. Explain how the Companies' Phase 2 analysis accounted for the value of any fixed or indexed capital and operating costs or performance guarantees reflected in proposals for long-term power supply alternatives when compared to non-binding cost estimates and performance levels of the Green River NGCC project.

A-146. At no time in the RFP process did any party make a proposal that was "binding." Specifically there were no binding fixed or indexed capital and operating costs or performance guarantees reflected in proposals for long-term power supply alternatives. Instead, all proposals were subject to negotiation and the execution of mutually agreeable definitive documents. Therefore there was no need to make the referenced analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 147

Witness: David S. Sinclair

Q-147. Provide electronic files supporting the weighted average results presented in Tables 19, 20, 21 and 22 of Exhibit DSS-1.

A-147. This information was provided in the response to PSC 1-22. The path and filename for the relevant Excel workbook is 02_Analysis\ 20130905_PivotP2-3Results_0073D10.xlsx.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 148

Witness: David S. Sinclair

Q-148. Reference Exhibit DSS-1, page 29, provide electronic files including the annual total nominal revenue requirements for each year, and cumulative PVRR calculation, for each of the 12 scenarios evaluated for each alternative as presented in Table 23.

A-148. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 149

Witness: David S. Sinclair

Q-149. Reference Exhibit DSS-1, page 29, provide the cumulative PVRR of imputed debt for each of the 12 scenarios evaluated for each PPA alternative presented in Table 23.

A-149. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 150

Witness: David S. Sinclair

Q-150. Reference Exhibit DSS-1, page 22, for each component of total revenue requirements modeled in the Phase 2 analysis as presented in Table 14, provide the annual nominal amount and cumulative PVRR calculation, for each year of each of the 12 scenarios evaluated for each alternative as presented in Table 23 on page 29 of Exhibit DSS-1.

A-150. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection. Fuel/energy costs, start costs, hourly operating costs, and variable O&M costs are grouped together and labeled "production costs."

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 151

Witness: David S. Sinclair

Q-151. Provide capital and operating cost assumptions used for the analysis of the Brown Solar Facility, along with the basis for such assumptions.

A-151. See Section 4.6 of Exhibit DSS-1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 152

Witness: David S. Sinclair

Q-152. Provide capital and operating costs and annual energy production levels reported for other existing solar facilities which were reviewed in the course of evaluating costs of the Brown Solar Facility.

A-152. See the response to Question No. 137 which attaches the HDR Study for the Brown Solar Facility. The Companies understand that HDR relied upon its expertise and its evaluation of existing solar facilities. In addition, see the response to Question No. 61.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 153

Witness: David S. Sinclair

Q-153. Provide forecasted annual energy (MWh) supplied from the Brown Solar Facility for each scenario evaluated including this project, along with the basis for such energy production forecasts.

A-153. In each scenario that included the Brown Solar Facility, it was assumed to produce 15,216 MWh per year. See the response to PSC 1-35.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 154

Witness: David S. Sinclair

Q-154. Provide the firm capacity credit associated with the Brown Solar Facility that will be reflected in the Companies' system reserve margin calculation.

A-154. Ninety percent (90%) of the capacity from the Brown Solar Facility is assumed to be available during the summer peak demand. This equates to 9 MW.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 155

Witness: David S. Sinclair

Q-155. Provide the percentage of the Companies total energy supply and percentage of total system firm capacity that will be supplied from the Brown Solar Facility.

A-155. In the Base load scenario in 2018, after Green River NGCC is commissioned, the percentage of Companies' total energy supply and system firm capacity supplied from the Brown Solar will be approximately 0.04% and 0.1%, respectively.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 156

Witness: Edwin R. Staton

Q-156. Provide the Companies' existing green energy tariffs and the total annual customers and energy sales made pursuant to these tariffs during the last four calendar years.

A-156. See attached Green Energy Rider tariffs for the Companies.

The Green Energy Program has no associated energy sales; instead it procures "Renewable Energy Certificates" (RECs) on behalf of its participants. Per the EPA, "A REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation." For every MWh of renewable electricity generated, an associated Renewable Energy Certificate is created. The Green Energy Program "retires" purchased RECs at the end of each year to signify that the program participants have made the associated environmental claims, ensuring that no other entity can lay claim to the same benefits. See the table below for the count of the Companies total annual unique customers and RECs purchased per year.

	# Customers	RECs Purchased
2010	2,084	34,179
2011	1,884	65,522
2012	1,707	53,739
2013	1,595	60,074

Standard Rate Rider **SGE**

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: June 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00467 dated February 22, 2010

Louisville Gas and Electric Company

Standard Rate Rider **LGE**

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, ITODP, CTODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Kentucky Utilities Company

Standard Rate Rider **SGE**
Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any Customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: June 1, 2010

ISSUED BY: /s/ Lonnie E. Bellar, Vice President
State Regulation and Rates
Lexington, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00467 dated February 22, 2010**

Kentucky Utilities Company

P.S.C. No. 16, Original Sheet No. 70.1

Standard Rate Rider **LGE**
Large Green Energy Rider

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS
a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE
Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS
a) Customers may contribute monthly as much as they like in $13.00 increments, (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.
c) Customer will be billed monthly for the amount customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 157

Witness: David S. Sinclair

Q-157. Identify any Kentucky renewable energy goals or policies that were considered in the Companies' decision to construct the Brown Solar Facility.

A-157. No. Kentucky renewable goals or policies were considered. See Section 4.6 of Exhibit DSS-1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 158

Witness: David S. Sinclair

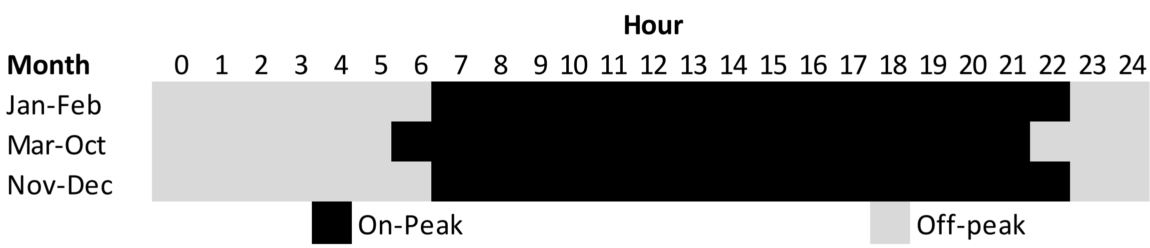
Q-158. Provide forecasted monthly on-peak and off-peak energy production levels as reflected in the Companies' economic analysis of the Brown Solar Facility.

A-158. See the table below. All of the Brown Solar Facility's generation is expected to occur in on-peak hours.

The table below lists the monthly on-peak and off-peak energy forecast.

Energy Production (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	611	810	1,207	1,502	1,784	1,940	1,878	1,776	1,385	1,066	697	559
Off-Peak	0	0	0	0	0	0	0	0	0	0	0	0

The table below provides the definition of on-peak and off-peak hours.



LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 159

Witness: David S. Sinclair

Q-159. Provide the results of economic modeling that was prepared to quantify the PVRR impact of constructing the Brown Solar Facility when compared to other available alternatives considered under a range of scenarios.

A-159. See Exhibit DSS-1 at pages 45-46. Tables 35, 36, and 37 summarize the PVRR impact of constructing the Brown Solar Facility over a range of scenarios and solar capital costs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 160

Witness: John N. Voyles, Jr.

Q-160. Provide a detailed capital cost estimate for the Brown Solar Facility, including any related transmission costs, construction interest costs.

A-160. See the response to PSC 1-31.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 161

Witness: David S. Sinclair

Q-161. Provide the Companies' quantification of the forecasted economic benefits attributable to increased fuel diversity and solar operating experience arising from ownership of the Brown Solar Facility.

A-161. The Companies did not quantify the economic benefits of increased fuel diversity or operating experience associated with the Brown Solar Facility.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 162

Witness: David S. Sinclair

Q-162. Provide the forecasted annual revenue requirement for the Brown Solar Facility expressed on a nominal dollars per year and $/MWh basis for each year of the forecasted life of the facility.

A-162. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 163

Witness: John N. Voyles, Jr.

Q-163. Reference Mr. Voyle's direct testimony, page 13, provide any analysis of the transmission modifications or upgrades necessary to support the Brown Solar Facility and indicate when the Companies plan to file an interconnect request with TransServ for this facility.

A-163. See the response to Question No. 91. The Companies currently intend to file an interconnection request with the ITO for the Brown Solar Facility in the 2nd quarter of this year.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 164

Witness: John N. Voyles, Jr.

Q-164. Provide the current schedule for the Brown Solar Facility with all major milestones identified.

A-164. See the response to PSC 1-31.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 165

Witness: David S. Sinclair

Q-165. Reference Exhibit DSS-1, page 44, provide documentation regarding the referenced Public Service of Colorado solar facilities purchase.

A-165. See footnote 34 on page 44 of Exhibit DSS-1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 166

Witness: David S. Sinclair

Q-166. Reference Exhibit DSS-1, page 44, provide documentation supporting the referenced market prices for solar RECs and explain why solar RECs from Kentucky cannot be sold in New Jersey, Maryland and Massachusetts markets.

A-166. See attached. At the time of developing Exhibit DSS-1, the market price in Ohio for solar RECs from Kentucky was $24-28 per REC. As of March 19, 2014, the market price in Ohio for solar RECs from Kentucky was $55-65 per REC. Each state with a solar renewable energy portfolio standard has different criteria for compliance utilizing out-of-state solar REC (SREC). The Companies have not performed an independent review of the compliance requirements of New Jersey, Maryland, and Massachusetts. Rather, their statement in Exhibit DSS-1 was based on conversations with brokers for SRECs that do business in those markets..

ICAP United, Inc
Ph: 281.340.8300
Fax: 281.340.8308
http://www.icapenergy.com/us/markets/EnvironmentalMarkets.aspx

ICAP

November 27, 2013

Emissions	Bid	Offer
CAIR Annual Nox	**Bid**	**Offer**
2013	36	39
CAIR Seasonal Nox	**Bid**	**Offer**
2013	15.00	20.00
CAIR SO2	**Bid**	**Offer**
2009	1.00	2.00
2012	0.50	1.00
RGGI	**Bid**	**Offer**
Dec'13 v13	2.90	3.00
Dec'14 v13	3.00	3.20
HGB Nox	**Bid**	**Offer**
10-perp	70,000	120,000
Solar		
NJ Solar	**Bid**	**Offer**
RY 2012	135.00	145.00
RY 2013	137.00	147.00
RY 2014	140.00	150.00
RY 2015	142.00	155.00
RY 2013-2014	142.00	150.00
RY 2013-2015	142.00	152.00
RY 2014-2015	142.00	155.00
RY 2014-2016	142.00	155.00
PA Solar	**Bid**	**Offer**
RY 2013	17	25
RY 2014	20	30
RY2013-2015	17.5	30
MD Solar	**Bid**	**Offer**
2013	135	145
2014	125	135
2015	125	135
2016	125	135
DC Solar	**Bid**	**Offer**
2012	465	490
2013	470	490
2014	450	480
DE Solar	**Bid**	**Offer**
CY 2013	30	40
NC Solar Out-of-State	**Bid**	**Offer**
2012	-	11.00
MA Solar	**Bid**	**Offer**
2013	235	245
2014	225	255
2015	220	255
2014-2015	220	255
2014-2016	220	255
OH-Sited Certified Solar	**Bid**	**Offer**
2012	40	50
2013	40	55
2013-2015	-	-
OH-Adj Certified Solar	**Bid**	**Offer**
2012	18	26
2013	24	28
Texas		
TX RECs Green-e	**Bid**	**Offer**
BH 2012	0.85	1.05
CAL 2012	0.85	1.10
FH 2013	0.90	1.15
BH 2013	0.90	1.15
CAL 2013	0.90	1.15
CAL 2014	1.10	1.25
CAL 2015	1.10	1.40
TX Compliance RECs	**Bid**	**Offer**
2011	0.80	1.05
2012	0.85	1.05
2013	0.90	1.15
2014	1.05	1.25
Michigan		
MI-RECs	**Bid**	**Offer**
2012	1.25	2.00
2013	1.20	2.25
WECC		
WECC REC	**Bid**	**Offer**
2012	-	1.35
2013	-	1.45

PJM	Bid	Offer
NJ Class I	**Bid**	**Offer**
RY 2012	12.00	12.90
RY 2013	12.25	13.00
RY 2014	12.50	13.15
RY 2015	12.55	13.25
RY 2016	12.60	13.50
NJ Class II	**Bid**	**Offer**
RY 2014	3.50	4.00
RY 2015	3.50	4.50
RY 2014-2016	3.50	5.00
PA Tier I	**Bid**	**Offer**
RY 2012	12.00	12.90
RY 2013	12.25	13.00
RY 2014	12.50	13.15
RY 2015	12.55	13.25
RY 2016	12.60	13.50
PA Tier II	**Bid**	**Offer**
RY 2012	-	0.07
RY 2013	-	0.10
DE New	**Bid**	**Offer**
CY 2011	10.50	-
CY 2012	11.00	12.00
CY 2013	11.10	12.25
DE Existing	**Bid**	**Offer**
CY 2012	0.50	-
CY 2013	0.50	-
DC Tier I	**Bid**	**Offer**
2012	2.15	2.50
2013	2.15	2.50
2014	2.15	2.75
2015	-	-
DC Tier II	**Bid**	**Offer**
2012	0.45	0.90
2013	0.45	1.00
MD Tier I	**Bid**	**Offer**
RY 2012	12.00	12.90
RY 2013	12.25	13.00
RY 2014	12.50	13.15
RY 2015	12.55	13.25
MD Tier II	**Bid**	**Offer**
2012	0.60	1.10
2013	0.60	1.10
2014	0.60	1.10
IL Wind	**Bid**	**Offer**
BH 2012	0.90	1.05
FH 2013	1.10	1.25
BH 2013	1.15	1.45
FH 2014	1.20	1.50
Ohio Sited	**Bid**	**Offer**
2012	12.00	13.30
2013	12.25	13.35
2014	12.50	13.40
Ohio Adjacent	**Bid**	**Offer**
2012	7.00	9.50
2013	9.00	11.00
VOLUNTARY and GREEN-e		
MRO Green-e Wind	**Bid**	**Offer**
FH 2012	0.80	1.00
BH 2012	0.85	1.05
CAL 2012	0.85	1.05
FH 2013	0.90	1.15
BH 2013	1.00	1.20
CAL 2013	1.05	1.25
FH 2014	1.10	1.35
BH 2014	1.15	1.40
CAL 2014	1.15	1.45
National Green-e Any	**Bid**	**Offer**
G-e RY 2012	0.80	1.10
G-e RY 2013	0.85	1.20
National Green-e Wind	**Bid**	**Offer**
CAL 2012	0.85	1.10
FH 2013	0.90	1.15
BH 2013	1.00	1.20
CAL 2013	1.05	1.25
FH 2014	1.05	1.30
BH 2014	1.10	1.35

NEPOOL	Bid	Offer
MA Class I	**Bid**	**Offer**
2013	63.75	64.75
2014	63.00	64.00
2015	56.25	57.75
2016	48.00	49.50
2017	38.00	40.00
MA Class II Waste	**Bid**	**Offer**
2013	7.50	8.75
2014	8.00	9.50
2013-2015	8.00	10.00
MA Class II Non-Waste	**Bid**	**Offer**
2013	25.50	26.50
2014	-	27.00
2015	-	-
MA APS	**Bid**	**Offer**
2013	19.75	-
2014	20.00	-
CT Class I	**Bid**	**Offer**
2013	54.00	55.00
2014	52.00	53.00
2015	49.50	50.50
2016	41.00	46.00
2017	40.00	42.50
CT Class II	**Bid**	**Offer**
2013	0.45	0.65
2014	0.40	0.75
CT Class III	**Bid**	**Offer**
2013	10.00	10.75
2014	19.00	21.00
2015	-	-
RI New	**Bid**	**Offer**
2013	64.00	65.00
2014	63.75	65.50
2015	58.25	60.00
2016	47.75	50.50
2017	-	-
RI Existing	**Bid**	**Offer**
2013	0.50	0.85
2014	-	-
ME New	**Bid**	**Offer**
2013	10.00	14.00
2014	13.00	17.00
ME Existing	**Bid**	**Offer**
2013	0.10	0.25
2014	0.10	0.50
NH Class I	**Bid**	**Offer**
2013	54.00	55.50
2014	54.00	56.50
2015	54.00	-
NH Class II	**Bid**	**Offer**
2013	54.00	-
NH Class III	**Bid**	**Offer**
2013	30.00	-
2014	30.00	-
NH Class IV	**Bid**	**Offer**
2013	26.00	-
California Carbon Allwances – Program Contingent		
CCA	**Bid**	**Offer**
ICE - Dec'13 v'13	11.75	11.90
ICE - Dec'14 v'14	11.80	12.40
ICE - Dec'15 v'15	11.90	12.90
Climate Action Reserve		
Forestry	**Bid**	**Offer**
	Call for pricing	
Ag Methane	**Bid**	**Offer**
	Call for pricing	
LFG	**Bid**	**Offer**
	Call for pricing	
CEC TREC	**Bid**	**Offer**
	Call for pricing	
CA RPS Power & REC	**Bid**	**Offer**
	Call for pricing	
PNW Wind	**Bid**	**Offer**
	Call for pricing	

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ICAP

March 19, 2014

Emissions

CAIR Annual Nox	Bid	Offer
2013	43	47
CAIR Seasonal Nox	**Bid**	**Offer**
2013	15.00	24.00
CAIR SO2	**Bid**	**Offer**
2009	1.00	1.50
2012	0.65	0.85
RGGI	**Bid**	**Offer**
Dec'14 v'13	4.20	4.30
Dec'14 v'14	4.25	4.35
HGB Nox	**Bid**	**Offer**
10-perp	70,000	120,000

Solar

NJ Solar	Bid	Offer
RY 2013	160.00	167.50
RY 2014	160.00	170.00
RY 2015	162.50	170.00
RY 2016	162.50	170.00
RY 2017	157.50	170.00
RY 2014-2015	161.00	170.00
RY 2014-2016	162.00	170.00
RY 2015-2016	162.50	170.00
RY 2015-2017	161.00	170.00
PA Solar	**Bid**	**Offer**
RY 2013	50	60
RY 2014	55	65
RY2014-2016	65	70
MD Solar	**Bid**	**Offer**
2013	140	150
2014	135	145
2015	130	145
2016	125	140
DC Solar	**Bid**	**Offer**
2012	465	490
2013	470	490
2014	475	490
DE Solar	**Bid**	**Offer**
CY 2013	30	40
NC Solar Out-of-State	**Bid**	**Offer**
2012	-	11.00
MA Solar	**Bid**	**Offer**
2013	260	270
2014	265	275
2015	265	275
2014-2015	265	275
2014-2016	265	275
OH-Sited Certified Solar	**Bid**	**Offer**
2012	55	60
2013	55	65
2013-2015	-	-
OH-Adj Certified Solar	**Bid**	**Offer**
2012	45	60
2013	55	65

Texas

TX RECs Green-e	Bid	Offer
BH 2012	1.00	1.10
FH 2013	1.00	1.15
BH 2013	1.00	1.20
CAL 2013	1.00	1.15
CAL 2014	1.10	1.25
CAL 2015	1.20	1.35
CAL 2016	1.30	1..55
TX Compliance RECs	**Bid**	**Offer**
2011	0.90	1.05
2012	1.00	1.15
2013	1.05	1.20
2014	1.05	1.25

Michigan

MI-RECs	Bid	Offer
2013	1.00	2.00
2014	0.90	2.25

WECC

WECC REC	Bid	Offer
2012	-	1.35
2013	-	1.45

PJM

NJ Class I	Bid	Offer
RY 2013	12.75	13.50
RY 2014	13.00	13.75
RY 2015	13.00	13.75
RY 2016	13.00	13.75
RY 2017	13.00	13.75
NJ Class II	**Bid**	**Offer**
RY 2014	9.50	11.00
RY 2015	9.50	11.00
RY 2014-2016	9.50	11.00
PA Tier I	**Bid**	**Offer**
RY 2013	12.75	13.50
RY 2014	13.00	13.75
RY 2015	13.00	13.75
RY 2016	13.00	13.75
RY 2017	13.00	13.75
PA Tier II	**Bid**	**Offer**
RY 2013	0.01	0.10
RY 2014	0.05	0.15
DE New	**Bid**	**Offer**
CY 2012	11.00	12.00
CY 2013	11.10	12.25
CY 2014	11.20	12.50
DE Existing	**Bid**	**Offer**
CY 2012	0.50	-
CY 2013	0.50	-
DC Tier I	**Bid**	**Offer**
2012	2.00	2.50
2013	2.15	2.50
2014	2.25	2.65
DC Tier II	**Bid**	**Offer**
2012	0.50	2.50
2013	1.00	2.50
2014	1.60	2.65
MD Tier I	**Bid**	**Offer**
2013	12.75	13.50
2014	13.00	13.75
2015	13.00	13.75
2016	13.00	13.75
MD Tier II	**Bid**	**Offer**
2012	4.00	4.25
2013	4.00	4.25
2014	4.00	4.25
IL Wind	**Bid**	**Offer**
BH 2012	1.00	1.15
FH 2013	1.20	1.30
BH 2013	1.25	1.35
FH 2014	1.30	1.40
BH 2014	1.35	1.45
Ohio Sited	**Bid**	**Offer**
2012	12.75	13.50
2013	13.00	13.75
2014	13.00	13.75
Ohio Adjacent	**Bid**	**Offer**
2012	11.50	12.50
2013	12.00	13.00

VOLUNTARY and GREEN-e

MRO Green-e Wind	Bid	Offer
FH 2012	0.80	1.00
BH 2012	0.95	1.05
CAL 2012	0.90	1.05
FH 2013	1.00	1.15
BH 2013	1.10	1.25
CAL 2013	1.05	1.25
FH 2014	1.10	1.30
BH 2014	1.15	1.40
CAL 2014	1.15	1.45
National Green-e Any	**Bid**	**Offer**
G-e RY 2013	1.00	1.20
National Green-e Wind	**Bid**	**Offer**
CAL 2012	1.00	1.10
FH 2013	1.00	1.15
BH 2013	1.00	1.20
CAL 2013	1.00	1.20
FH 2014	1.20	1.30
BH 2014	1.20	1.35

NEPOOL

MA Class I	Bid	Offer
2013	64.00	64.75
2014	63.00	64.00
2015	56.25	57.00
2016	47.00	48.00
2017	37.00	38.00
MA Class II Waste	**Bid**	**Offer**
2013	7.75	8.90
2014	8.50	9.25
2015	8.75	9.50
MA Class II Non-Waste	**Bid**	**Offer**
2013	25.50	26.50
2014	-	27.00
2015	-	-
MA APS	**Bid**	**Offer**
2013	19.75	-
2014	20.00	-
CT Class I	**Bid**	**Offer**
2013	54.00	55.00
2014	51.50	52.00
2015	47.00	50.00
2016	41.00	43.00
2017	40.00	42.50
CT Class II	**Bid**	**Offer**
2013	0.40	0.50
2014	0.40	0.65
CT Class III	**Bid**	**Offer**
2013	10.00	10.75
2014	16.00	18.00
2015	-	-
RI New	**Bid**	**Offer**
2013	63.75	64.75
2014	62.00	63.25
2015	54.50	56.75
2016	45.00	47.25
RI Existing	**Bid**	**Offer**
2013	0.50	0.85
2014	-	-
ME New	**Bid**	**Offer**
2013	1.00	3.00
2014	4.00	7.00
2015	6.50	10.00
ME Existing	**Bid**	**Offer**
2013	0.10	0.25
2014	0.10	0.50
NH Class I	**Bid**	**Offer**
2013	54.00	55.50
2014	54.00	56.50
2015	54.00	-
NH Class II	**Bid**	**Offer**
2013	54.00	-
NH Class III	**Bid**	**Offer**
2013	30.00	-
2014	30.00	-
NH Class IV	**Bid**	**Offer**
2013	26.00	-

California Carbon Allwances – Program Contingent

CCA	Bid	Offer
ICE - Dec'14 v'13	11.80	12.00
ICE - Dec'14 v'14	11.90	12.10
ICE - Dec'15 v'15	12.10	12.30
ICE - Dec'16 v'16	12.55	12.80

Climate Action Reserve

Forestry	Bid	Offer
	Call for pricing	
Ag Methane	**Bid**	**Offer**
	Call for pricing	
LFG	**Bid**	**Offer**
	Call for pricing	

CEC TREC	Bid	Offer
	Call for pricing	
CA RPS Power & REC	**Bid**	**Offer**
	Call for pricing	
PNW Wind	**Bid**	**Offer**
	Call for pricing	

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LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 167

Witness: John N. Voyles, Jr.

Q-167. Reference Exhibit DSS-1, page 45,provide the referenced updated HDR solar cost study.

A-167. See the response to Question No. 137.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 168

Witness: David S. Sinclair

Q-168. Provide the estimated percentage reduction in total system annual carbon emissions attributable to the Brown Solar Facility.

A-168. In its first full year of operation (2017), the Brown Solar Facility is expected to reduce total system carbon emissions by approximately 0.04% in the Base load, Base gas scenario. This equates to a reduction of approximately 15,400 tons of CO_2.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 169

Witness: John N. Voyles, Jr.

Q-169. Provide the current schedule for the Green River NGCC project with all major milestones identified.

A-169. See the response to PSC 1-30.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 170

Witness: John N. Voyles, Jr.

Q-170. Provide the current schedule for the Cane Run NGCC project with all major milestones identified.

A-170. See attached.

CANE RUN 7 NGCC PROJECT   Actuals thru: 21-Feb-14

Schedule - Milestones	Plan (date)	Re-Baseline Plan (date)	Actual (date)
Limited Notice to Proceed (LNTP)/Start Detailed Engr/Procurement	7/2/2012		7/2/2012
Full Notice to Proceed (NTP)	12/3/2012		12/3/2012
Award Structural Steel	12/17/2012		2/20/2013
Award GSU Transformer	12/17/2012		1/7/2013
First Steel Mill Order Release**	12/18/2012		6/28/2013
Award Cooling Tower S/C	12/18/2012		1/16/2013
Award Boiler Feedwater Pump(s)	1/23/2013		3/12/2013
Award Demin Equipment	2/13/2013		2/18/2013
Award DCS	2/22/2013		2/28/2013
AFC HRSG Foundation(s)	2/25/2013		2/28/2013
Award Alloy/HP Pipe	3/12/2013		4/12/2013
AFC ST Foundation	4/4/2013		4/4/2013
AFC CT Foundation(s)	4/30/2013		4/3/2013
First Alloy Pipe Mill Order Release	5/6/2013		4/12/2013
IFF LB Alloy Pipe Iso's	07/29/13		5/31/2013
Set GSU Transformer	01/07/14		11/13/2013
AFC First Volume Steel	07/26/13		7/24/2013
Set CT on Base (UNIT 1)	11/04/13		11/4/2013
Set Aux Transformer	01/10/14		11/1/2013
Set CT on Base (UNIT 2)	12/04/13		11/15/2013
Set STG on Base	12/12/13	2/5/2014	2/5/2014
Complete Erection of Cooling Tower- Ready for Checkout	10/16/14	05/29/14	
DCS Energized & Available for Startup	07/11/14	04/23/14	
Energize Aux Electric/Backfeed Power Available	07/09/14	06/16/14	
Demin Water Available- System Operational	08/19/14	08/11/14	
Complete HRSG Hydro (UNIT 1)	07/31/14	09/17/14	
Complete HRSG Hydro (UNIT 2)	09/12/14	09/17/14	
Complete STG Lube Oil Flushes	10/15/14	08/18/14	
Complete CT Lube Oil Flushes (UNIT 1)	10/21/14	09/22/14	
Complete CT Lube Oil Flushes (UNIT 2)	10/21/14	09/22/14	
STG on Turning Gear	10/29/14	10/08/14	
First Fire On Gas	11/18/14	11/17/14	
Initial Steam Admission to Steam Turbine	01/14/15	01/08/15	
Complete Chemical Cleaning	10/28/14	10/22/14	
Complete Steam Blows	12/19/14	12/10/14	
Initial ST Synchronization	01/14/15	01/08/15	
Initial Full Load Operation	02/03/15	01/26/15	
Planned Substantial Completion (PSCD)	03/05/15	03/02/15	
Guaranteed Substantial Completion (GSCD)	05/01/15	05/01/15	

**Due to the market availability of steel, the duration for the steel mill order has decreased. As a result, this has pushed the First Steel Mill Order out.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 171

Witness: David S. Sinclair

Q-171. Provide any analysis by the Companies of the extent to which the existing regional natural gas pipeline infrastructure will be adequate to reliably deliver firm fuel supply requirements of the Green River and Cane Run NGCC projects over the 30-year study period addressed in the 2013 Resource Assessment.

A-171. The Companies have rollover rights for the gas transportation on Texas Gas Transmission for Cane Run NGCC. See the response to Question No. 52(k) related to Green River NGCC.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 172

Witness: David S. Sinclair

Q-172. Provide the timeframe in which the Phase 2 economic modeling presented in the 2013 Resource Assessment was performed.

A-172. The Phase 2 analysis began in December 2012 (after the Phase 1 screening analysis was initially completed) and continued through the 3rd quarter of 2013.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 173

Witness: John N. Voyles, Jr.

Q-173. Reference Mr. Voyle's direct testimony, page 5, discuss circumstances under which a transmission CPCN might be needed for the Green River NGCC project and explain how the need for a transmission CPCN would be expected to impact the planned in-service date for the plant.

A-173. The circumstances under which a transmission CPCN would be necessary are set forth at KRS 278.020 and 807 KAR 5:120. To the extent those circumstances arise, the Companies would seek a transmission CPCN on a schedule that would not affect the planned in-service date for the plant.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 174

Witnesses: Gary H. Revlett

Q-174. Reference Mr. Voyle's direct testimony, page 5, explain the referenced net out of PSD air permitting process; provide regulations that address this net out provisions; and identify the estimated cost increase that would be incurred if Green River was delayed such that it could not take advantage of this net out provision.

A-174. As described in the responses to Question Nos. 81 and 132, the netting calculations are based upon a comparison of the future potential emission increases/decreases above the baseline existing emissions for each regulated pollutant. If the comparison shows an increase in emissions above the regulatory trigger amount for that pollutant, then Prevention of Significant Deterioration (PSD) is triggered. As previously described the baseline emissions are based on a 5-year (contemporaneous) look back period.

The PSD regulations are incorporated into the Kentucky State Implementation Plan (SIP) in 401 KAR 51.017. As specified in 401 KAR 51:017, Section 1(2), PSD permitting requirements apply to the construction of a major modification at an existing major stationary source. As specified in 401 KAR 51:017, Section 1(4), a project is a major modification for a regulated New Source Review (NSR) pollutant only if the project causes a significant emissions increase and a significant net emissions increase. Net emissions increase is defined in 401 KAR 51:001, Section 1(144) and includes increases in emissions from a particular physical change and increases or decreases in actual emissions that are contemporaneous (i.e., those changes that occur between the date five (5) years before construction on the change commences and the date that the increase from the change occurs) with the particular change.

Without netting of existing emissions, PSD would be triggered for NO_x. Additional capital and operational costs would primarily be incurred with the need to install and operate a Selected Catalytic Reduction System (SCR) which is Best Available Control Technology (BACT) for NO_x.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 175

Witness: John N. Voyles, Jr.

Q-175. Reference Mr. Voyle's direct testimony, page 5, provide any analysis that was conducted to quantify the increase in reliability of energy supply to Western Kentucky arising from the construction of the proposed Green River NGCC when compared to the alternative of relying more heavily on the transmission grid to transmit power to that area.

A-175. See the response to Question No. 33

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 176

Witness: David S. Sinclair

Q-176. Provide the amount of replacement capacity that would have to be procured by the Companies in 2018 and 2019 if the in-service date of the Green River NGCC was delayed by two years.

A-176. See Table 1 of Exhibit DSS-1 at page 4. Without the Green River NGCC, the Companies' reserve margin shortfall would be 211-355 MW in 2018 and 289-434 MW in 2019.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 177

Witness: John N. Voyles, Jr.

Q-177. Reference Mr. Voyle's direct testimony, page 10, provide the referenced Combined Cycle Feasibility Study Life Cycle Cost Analysis prepared by HDR.

A-177. See attached.

7.0 NGCC LIFECYCLE COST ANALYSES

Detailed life cycle analyses have been completed to determine a cost of generation for each of the NGCC arrangements under evaluation. For reference, the life cycle analyses have been provided in Appendix G for the NGCC options considered herein. The following provides a summary description of each component of the cost of generation of electricity.

7.1 OPERATING AND MAINTENANCE COSTS

Fully burdened plant operations and maintenance staff as well as other fixed costs associated with facility operations such as building and site maintenance, insurances, and property taxes are summarized in Table 7.1-1. Escalation has been applied to these costs at 0.9 percent per year.

Table 7.1-1. Fixed Cost Assumptions

Fixed Cost	First Year Price (2018)
Annual Cost for Salaried Staff	$126,586
Annual Cost for Hourly Staff	$101,268
Insurance	0.106% of EPC Project Cost
Property Tax	0.150% of EPC Project Cost
Annual Site / Building Maintenance Cost	$139,244

Table 7.1-2, provides the assumed number of NGCC facility personnel on a salaried staff and hourly staff basis.

Table 7.1-2. NGCC Facility Personnel

Option	Description	Salaried Staff	Hourly Staff
1	1 x 1 7F 5	7	24
2	1 x 1 SGT6-5000F(5)ee	7	24
3	1 x 1 GAC	7	24
4	1 x 1 SGT6-8000H	7	24
5	2 x 1 7F 5	7	24
6	2 x 1 SGT6-5000F(5)ee	7	24

Equipment parts and maintenance costs are included in the analysis as fixed and variable O&M costs and are dependent upon maintenance schedules and hours of operation of the equipment. These costs have included expenses for replacement parts and outsourced labor to perform major maintenance on the combustion turbines, steam turbines, HRSGs, and other major equipment. Escalation has been applied to these costs at 2.4 percent per year.

Consumable costs include costs for material delivery and disposal for all of the materials utilized within the power generation process. These consumable costs include items such as ammonia, water, water treatment chemicals, and spare parts.

The plant will be installed with air quality control equipment intended to comply with reasonable emissions limits dictated by federal and state authorities, therefore emissions allowances have not been incorporated into the evaluation.

Unit costs used in the evaluation for the consumables and emissions allowances are as defined below in Table 7.1-3.

Table 7.1-3. Consumable Cost Basis

Consumable	First Year Unit Price (2018)
Consumable Escalation Rate	0.9%
Ammonia (as 19% Aqueous)	$165.69 / Ton
Clarified Water	$1.49 / kgal
Demineralized Water	$4.68 / kgal
Cycle Chemical Feed	$0.012 / Ton steam produced

7.2 FUEL COSTS

Fuel costs are strictly a function of the cost of fuel as delivered to the facility. These are then converted to a $/MWH basis by utilizing the cycle heat rates. The first year cost of fuel assumed for this evaluation is defined below in Table 7.2-1 with the forecast pricing indicated in Figure 7.2-1.

Table 7.2-1. Fuel Costs

Fuel Cost Assumptions		
Year		2018
Natural Gas	(US$/mmBtu)	$4.96

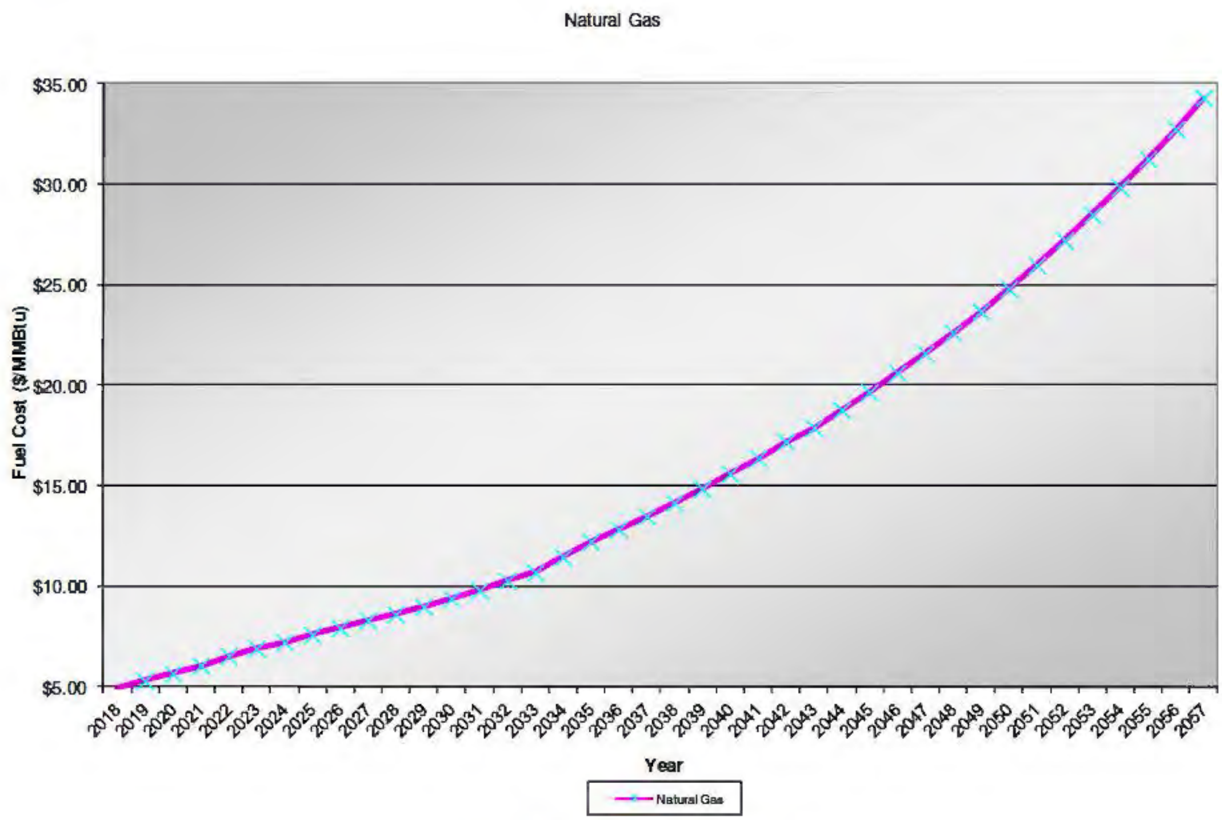

Figure 7.2-1 Fuel Cost Forecast

Table 7.2-2, depicts the annual demand charge Texas Eastern intends to invoice the proposed NGCC facility based on the NGCC option chosen. The annual demand charge was determined by the maximum natural gas demand required on a heat input per day MMBTU/day) basis, which correlates to the 99 percent winter design condition. A 24 hour operational period was used to determine the demand charge since a demand charge is usually determined on potential rather than typical or actual use (24 hours potential rather than 16 hours actual or typical). The annual demand charge remains constant for the life of the NGCC facility.

Table 7.2-2. Annual Natural Gas Demand Charge

	Description	Natural Gas Annual Demand Charge
1	1 x 1 7F 5	$7,172,281
2	1 x 1 SGT6-5000F(5)ee	$8,062,268
3	1 x 1 GAC	$8,950,089
4	1 x 1 SGT6-8000H	$8,836,199
5	2 x 1 7F 5	$14,344,562
6	2 x 1 SGT6-5000F(5)ee	$16,124,536

7.3 CAPITAL RECOVERY COSTS

Fixed capacity payments, or capital recovery costs have been established for this analysis based upon a 45.7 percent debt / 54.3 percent equity financing approach with a 6.75 percent rate of return expectation on that money. A 20 year debt term has been assumed with an interest rate of 3.73 percent. Capital cost differentials have been utilized as identified in Section 9.0.

Tax depreciation has been assumed based upon a 20 year MACRS schedule with book depreciation assumed as straight line over 30 years. To summarize other factors utilized to determine the fixed capacity payments, Table 7.3-1 is provided.

Table 7.3-1 Economic Assumptions

Common Proforma Parameters	
Discount Rate	6.75%
Depreciation Schedule - Tax	20 Year MACRS
Depreciation Schedule - Book	30 Year SL
Amortization	30 Years
Project Life	30 Years
Capital Escalation	2.40%
Income Tax Rate	38.90%
IRR	6.75%
Debt	45.7%
Interest Rate	3.73%

7.4 SUMMARY OF LIFECYCLE COST ANALYSIS

Incorporating all of the above capital cost expectations and operating and maintenance costs, the total cost of generation values for each intermediately loaded NGCC option have been presented in Table 7.4-1. Costs are presented on both a first year basis and a 30 year levelized basis for an intermediately loaded plant. Detailed data for the first 20 years of the lifecycle models for these cases are included in Appendix G.

Table 7.4-1. NGCC Electrical Cost of Generation Summary (Intermediate Load Dispatch)

		NGCC 1	NGCC 2	NGCC 3	NGCC 4	NGCC 5	NGCC 6
		1 x 1 7F 5	1 x 1 SGT6-5000F(5)ee	1 x 1 GAC	1 x 1 SGT6-8000H	2 x 1 7F 5	2 x 1 SGT6-5000F(5)ee
Gross Output	(MW)	314.3	351.6	393.0	399.6	629.4	704.7
Auxiliary Power	(MW)	6.9	8.0	9.7	9.8	13.8	16.0
Net Output	(MW)	307.4	343.7	383.2	389.8	615.5	688.7
Net Cycle Heat Rate, HHV	(Btu/kWH)	6,642	6,679	6,649	6,453	6,634	6,665
Net Cycle Efficiency	(% HHV)	51.42%	51.15%	51.38%	52.93%	51.49%	51.25%
Capital Cost	($/kW net)	$1,421	$1,214	$1,196	$1,162	$1,016	$900
First Year Cost of Generation							
Capital Recovery	($/MWH)	$29.01	$24.74	$24.37	$23.65	$20.67	$18.28
Fixed O&M	($/MWH)	$6.10	$4.04	$3.97	$3.76	$3.69	$2.66
Variable O&M	($/MWH)	$1.45	$2.61	$3.27	$3.47	$1.17	$2.60
Consumables	($/MWH)	$2.72	$2.65	$2.63	$2.58	$2.56	$2.52
Fuel Costs	($/MWH)	$38.88	$39.09	$38.92	$37.77	$38.84	$39.02
Total COG	($/MWH)	$78.16	$73.13	$73.16	$71.23	$66.92	$65.08
Levelized Cost of Generation							
Capital Recovery	($/MWH)	$29.01	$24.74	$24.37	$23.65	$20.67	$18.28
Fixed O&M	($/MWH)	$7.10	$4.50	$4.46	$4.20	$4.30	$3.01
Variable O&M	($/MWH)	$1.89	$3.43	$4.31	$4.57	$1.52	$3.42
Consumables	($/MWH)	$4.72	$4.63	$4.60	$4.49	$4.50	$4.46
Fuel Costs	($/MWH)	$68.07	$68.44	$68.13	$66.13	$67.99	$68.31
Total Levelized COG	($/MWH)	$110.78	$105.74	$105.87	$103.04	$98.98	$97.48

As shown in Table 7.4-1 a 2x1 combustion turbine arrangement produces a lower cost of generation than that of a 1x1 arrangement. The first year cost of generation ranges from approximately $65 per MWH for a 2x1 F class combined cycle plant arrangement to $78 per MWH for a 1x1 F class combined cycle plant configuration. The 1x1 SGT6-8000H (NGCC 4) provides the lowest cost of generation for a 1x1 plant configuration at $71 per MWH. The 2x1 SGT6-5000F(5)ee plant configuration (NGCC 6) provides the lowest cost of generation for all of the options considered.

For comparison, the cost of generation also has been developed for a base load facility operating at 8,400 hours annually. LTSA costs have been modified to reflect the OEM provided values based on an equivalent operating hours basis rather than an equivalent number of starts basis. Table 7.4-2 summarizes the first year and levelized cost of generation for each option in the case of a base load facility.

Table 7.4-2. NGCC Electrical Cost of Generation Summary (Base Load Dispatch)

		NGCC 1	NGCC 2	NGCC 3	NGCC 4	NGCC 5	NGCC 6
		1 x 1 7F 5	1 x 1 SGT6-5000F(5)ee	1 x 1 GAC	1 x 1 SGT6-8000H	2 x 1 7F 5	2 x 1 SGT6-5000F(5)ee
Gross Output	(MW)	314.3	351.6	393.0	399.6	629.4	704.7
Auxiliary Power	(MW)	6.9	8.0	9.7	9.8	13.8	16.0
Net Output	(MW)	307.4	343.7	383.2	389.8	615.5	688.7
Net Cycle Heat Rate, HHV	(Btu/kWH)	6,642	6,679	6,649	6,453	6,634	6,665
Net Cycle Efficiency	(% HHV)	51.42%	51.15%	51.38%	52.93%	51.49%	51.25%
Capital Cost	($/kW net)	$1,421	$1,214	$1,196	$1,162	$1,016	$900
First Year Cost of Generation							
Capital Recovery	($/MWH)	$14.57	$12.42	$12.23	$11.87	$10.37	$9.18
Fixed O&M	($/MWH)	$3.06	$2.03	$1.99	$1.89	$1.85	$1.33
Variable O&M	($/MWH)	$0.78	$1.56	$1.96	$2.08	$0.62	$1.56
Consumables	($/MWH)	$0.49	$0.45	$0.44	$0.44	$0.41	$0.39
Fuel Costs	($/MWH)	$36.09	$36.28	$36.12	$35.06	$36.04	$36.21
Total COG	($/MWH)	$54.98	$52.74	$52.74	$51.33	$49.30	$48.67
Levelized Cost of Generation							
Capital Recovery	($/MWH)	$14.57	$12.42	$12.23	$11.87	$10.37	$9.18
Fixed O&M	($/MWH)	$3.56	$2.26	$2.24	$2.11	$2.16	$1.51
Variable O&M	($/MWH)	$1.02	$2.03	$2.55	$2.70	$0.81	$2.02
Consumables	($/MWH)	$0.64	$0.59	$0.58	$0.58	$0.53	$0.50
Fuel Costs	($/MWH)	$65.21	$65.57	$65.27	$63.35	$65.13	$65.44
Total Levelized COG	($/MWH)	$84.99	$82.86	$82.87	$80.61	$79.01	$78.65

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 178

Witness: John N. Voyles, Jr.

Q-178. Reference Mr. Voyle's direct testimony, page 11, provide any analysis conducted by the Companies' to confirm the reasonableness of HDR's forecasted fixed and variable O&M costs for the Green River NGCC facility.

A-178. The O&M costs are consistent with costs currently known to the Companies. For example, steam turbine maintenance costs or the cost of producing boiler water are not materially different between a NGCC or a coal fired steam unit. The principal differences between a NGCC and a conventional steam unit are the gas turbine maintenance costs. These costs are largely covered by a Long Term Maintenance Agreement (LTSA) with the Original Equipment Manufacturer (OEM). The Companies signed an LTSA with Siemens for Cane Run 7 and the HDR projected F class O&M costs are consistent with that agreement. HDR solicited LTSA costs for advanced class gas turbines from each of the OEMs. These costs were incorporated into the advanced class O&M projections. The Companies had independent conversations with each OEM to verify the advanced class O&M projections. The Companies also visited the FP&L Canaveral plant to verify O&M experiences.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 179

Witness: John N. Voyles, Jr.

Q-179. Reference Mr. Voyle's direct testimony, page 11, provide the referenced analysis by the Companies' Transmission staff of possible transmission modifications and related costs to support the Green River NGCC.

A-179. Based on preliminary studies conducted by the Companies' Transmission engineers, the analysis of possible transmission modifications and related costs to support the Green River NGCC included the following:

<u>Upgrades and New Facilities:</u> (Total Estimated Cost $98,739k)

- Transmission Owner Assets from the point of interconnection to the transmission network facilities: (Total Estimated Cost $10,900k)
  - 13 – Breakers
  - 26 – Breaker Switches
  - Structures, insulators, foundations, and other associated equipment for the above three items
  - Controls for the switches and breaker
  - Breaker panel in control house
  - Wiring for breaker panel to and in the control house
- Transmission Network Upgrades (Total estimated cost $87,839k)
  - Conductor upgrades ($46,558k)
  - Line clearance upgrades ($13,000k)
  - Terminal equipment upgrades ($1,700k)
  - Transformer replacement/additions ($25,656k)
  - Capacitor installations ($925k)

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 180

Witness: David S. Sinclair

Q-180. Provide the estimated percentage uncertainty in the capital cost estimate for the Green River NGCC which was used for the Phase 2 economic analyses of the project in comparison to alternatives.

A-180. The Phase 2 analysis did not consider the uncertainty in capital and operating cost for the Green River NGCC or any other alternatives.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 181

Witness: David S. Sinclair

Q-181. Reference Mr. Revlett's direct testimony, page 5, provide the annual CO_2 emissions and average annual CO_2 emission rate (lbs CO_2/MWh) for the Green River NGCC project and each other NGCC alternative evaluated for each year of each scenario evaluated in the Phase 2 Resource Assessment analysis.

A-181. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 182

Witness: Gary H. Revlett

Q-182. Reference Mr. Revlett's direct testimony, page 10, identify any proposed or anticipated regulations of power plant cooling water intake and discharge facilities that may apply to the Green River NGCC project and provide the estimated cost impact of such future regulations on the project.

A-182. EPA is currently required to finalize revisions to the Clean Water Act Section 316(b) by April 17, 2014. Those revisions are anticipated to include various operational options which would reduce adverse environmental impact on aquatic organisms, including the use of closed cycle cooling (cooling towers) to reduce the volume of cooling water withdrawn from source waters. The Green River NGCC project includes closed cycle cooling at an estimated construction cost of $20M.

The only anticipated discharge regulation would be revisions to the Effluent Limitations Guidelines; however those revisions are addressing scrubber wastewater and landfill leachate from coal-fired operations and are not applicable for this project.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 183

Witness: David S. Sinclair

Q-183. Fleet Dispatch:

a. Please confirm that both LG&E and KU dispatch their fleets on a joint basis.

b. If you confirm the question in subpart (a), above, please confirm that the Companies continue to dispatch their fleet in economic order of dispatch.

c. If you confirm the questions in subparts (a) and (b), above, please state whether the Cane Run 7 combined cycle unit ("CR 7"), once on-line and ready for dispatch, will cause the Companies to no longer dispatch in economic order.

d. Please state whether CR 7, once on-line and ready for dispatch, will cause the Companies to in any manner alter their combined fleets' order of economic dispatch. Include in your response: (i) a list of all generating units in rank-order depicting the most frequently dispatched unit first, concluding with the least-dispatched unit at the end of the list; (ii) hours of operation for each unit for each of the last five (5) years; and (iii) any and all estimates or projections of any type or sort depicting where CR 7 will fall within the order of economic dispatch.

e. If you confirm the questions in subparts (a) and (b), above, please state whether the proposed Green River NGCC unit, once on-line and ready for dispatch, will cause the Companies to no longer dispatch in economic order.

f. Please state whether the proposed Green River NGCC unit, if approved, constructed, and once on-line and ready for dispatch, will cause the Companies to in any manner alter the their combined fleets' order of economic dispatch. Based on your response to subpart (d), above, provide any and all estimates or projections of any type or sort depicting where the Green River combined cycle unit will fall within the order of the Companies' order of economic dispatch.

g. As between CR 7 and the proposed Green River NGCC unit, provide any and all information, studies, reports, or analyses of any type or sort indicating the number of projected hours of dispatched operation per year for each plant over the projected life span of each plant.

h. Based on the Companies' responses to subparts (d) and (f), above, explain how the Companies' responses to those subparts would differ based on each of the following natural gas price sensitivities [per mmBtu] of: (i) $5.00; (ii) $5.50; (iii) $6.00; (iv) $6.50; (v) $7.00; (vi) $7.50; (vii) $8.00; (viii) $8.50; (ix) $9.00; (x) $9.50; (xi) $10.00; (xi) $10.50 and (xii) $11.00.

i. Based on to your response to subpart (h), above, provide an explanation of how the differing price sensitivities could or would affect the economic order of dispatch of both the proposed Green River NGCC and CR 7.

j. Please provide an explanation of whether or how the economic order of dispatch for both CR 7 and the proposed Green River NGCC will or could change if the Companies join an RTO.

k. Please provide copies of any and all sensitivity analyses prepared by or for the Companies regarding natural gas prices, including any and all input and output files, workpapers and source documents. Where this information was inputed into Excel spreadsheets, please provide electronic versions of those spreadsheets with formulae intact and cells unprotected.

A-183.

a. The Companies' fleets are jointly dispatched.

b. The Companies joint fleet is economically dispatched.

c. The addition of Cane Run 7 will <u>not</u> change the Companies' objective to economically dispatch the joint fleet.

d. Cane Run 7 will be placed in the fleet generation stack based on its variable operating costs and operating parameters consistent with the information required for all generating units in the fleet (coal and natural gas). This stack is reviewed daily based primarily on changes in fuel costs at each plant. See the response to Question No. 104 for the Companies' current dispatch order. The table below lists the hours of operation for each unit for each of the last five years.

	Hours of Operation				
Unit	2009	2010	2011	2012	2013
Brown 1	3,278	6,882	6,295	6,508	7,522
Brown 2	5,229	7,299	6,316	7,335	7,672
Brown 3	6,799	6,991	6,534	5,596	7,120

Brown 5	69	134	84	113	82
Brown 6	509	558	428	1,093	546
Brown 7	267	646	345	783	410
Brown 8	138	147	89	51	57
Brown 9	41	113	103	130	88
Brown 10	46	98	54	48	33
Brown 11	84	140	52	98	39
Cane Run 4	7,807	7,315	8,080	6,474	6,478
Cane Run 5	7,321	8,271	7,736	7,532	7,623
Cane Run 6	7,150	6,616	7,758	7,007	7,338
Cane Run 11	20	20	18	37	36
Dix Dam	3,982	2,064	3,983	2,540	4,245
Ghent 1	7,043	7,734	8,054	7,522	8,153
Ghent 2	6,634	8,301	8,429	7,118	8,398
Ghent 3	7,770	8,128	7,055	7,688	7,814
Ghent 4	7,938	6,740	7,957	7,718	7,619
Green River 3	4,469	6,821	6,896	6,408	7,092
Green River 4	6,248	7,931	6,494	7,601	7,632
Haefling	3	29	29	47	35
Mill Creek 1	8,137	7,636	7,840	8,156	6,304
Mill Creek 2	7,394	7,921	7,900	6,438	8,057
Mill Creek 3	7,739	8,102	5,439	7,994	6,860
Mill Creek 4	8,110	7,460	7,282	6,090	7,204
Ohio Falls	6,220	6,199	5,384	5,685	6,123
Paddys Run 11	2	26	13	26	3
Paddys Run 12	0	12	7	42	2
Paddys Run 13	9	107	264	467	221
Trimble County 1	6,534	7,704	6,951	8,134	7,553
Trimble County 2	N/A	N/A	6,246	4,930	6,056
Trimble County 5	370	1,137	590	1,675	708
Trimble County 6	240	874	634	1,826	912
Trimble County 7	345	1,140	733	841	755
Trimble County 8	296	863	520	746	268
Trimble County 9	251	1,118	753	1,759	890
Trimble County 10	179	908	465	616	285
Zorn 1	13	20	4	60	29

The Companies will dispatch Cane Run 7 economically within the generating fleet, in the same way that all generating units are dispatched. The table below shows the Companies' expected dispatch order in July of 2016 for each natural gas price scenario, based on assumptions from the 2013 Resource Assessment.

Low Gas Price			Mid Gas Price			High Gas Price	
Rank	Unit		Rank	Unit		Rank	Unit
1	CR7		1	TC2		1	TC2
2	TC2		2	TC1		2	TC1
3	TC1		3	GH2		3	GH2

4	GH2	4	OVEC	4	OVEC
5	OVEC	5	MC2	5	MC2
6	MC2	6	MC1	6	MC1
7	MC1	7	GH1	7	GH1
8	GH1	8	GH3	8	GH3
9	GH3	9	GH4	9	GH4
10	GH4	10	MC4	10	MC4
11	MC4	11	MC3	11	MC3
12	MC3	12	CR7	12	BR2
13	BR2	13	BR2	13	BR1
14	BR1	14	BR1	14	BR3
15	BR3	15	BR3	15	CR7
16	PR13	16	PR13	16	PR13
17	TC5	17	TC5	17	TC5
18	TC6	18	TC6	18	TC6
19	TC7	19	TC7	19	TC7
20	TC8	20	TC8	20	TC8
21	TC9	21	TC9	21	TC9
22	TC10	22	TC10	22	TC10
23	BR 6	23	BR 6	23	BR 6
24	BR 7	24	BR 7	24	BR 7
25	BR 5	25	BR 5	25	BR 5
26	BR 8	26	BR 8	26	BR 8
27	BR11	27	BR11	27	BR11
28	BR 9	28	BR 9	28	BR 9
29	BR10	29	BR10	29	BR10
30	PR11	30	PR11	30	PR11
31	PR12	31	PR12	31	PR12
32	CR11	32	CR11	32	CR11
33	HF	33	ZN1	33	ZN1
34	ZN1	34	HF	34	HF

e. The addition of Green River NGCC will <u>not</u> change the Companies' objective to economically dispatch the joint fleet.

f. Green River NGCC will be placed in the fleet generation stack based on its variable operating costs and operating parameters consistent with the information required for all generating units in the fleet (coal and natural gas). This stack is reviewed daily based primarily on changes in fuel costs at each plant. Because Green River NGCC will be a newer NGCC unit than Cane Run 7, it is expected to be at least as efficient as Cane Run 7, and would therefore be dispatched immediately before Cane Run 7.

g. See attached.

h. This analysis has not been performed. The responses to subparts (d) and (f) contain the information for the three natural gas price forecasts utilized in Exhibit DSS-1.

i. As can be seen in the responses to subparts (d) and (f), Cane Run 7 and Green River NGCC will dispatch more at lower natural gas prices as compared to higher natural gas prices.

j. The dispatch cost for all of the Companies' generation units is the same whether they are inside or outside an RTO. The Companies have not performed any detailed analysis of how the generation fleet would be dispatched in an RTO.

k. See Exhibit DSS-1, Table 7 on page 12. See attached.

Operating Hours of Cane Run 7 and the Green River NGCC Unit (Hours)

Year	Unit	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon
2013	Cane Run 7	0	0	0	0	0	0	0	0	0	0	0	0
	Green River NGCC	0	0	0	0	0	0	0	0	0	0	0	0
2014	Cane Run 7	0	0	0	0	0	0	0	0	0	0	0	0
	Green River NGCC	0	0	0	0	0	0	0	0	0	0	0	0
2015	Cane Run 7	5,322	5,322	5,578	5,578	4,643	4,643	5,168	5,168	5,569	5,569	4,285	4,285
	Green River NGCC	0	0	0	0	0	0	0	0	0	0	0	0
2016	Cane Run 7	8,088	8,088	8,347	8,347	6,576	6,576	8,041	8,041	8,342	8,342	5,872	5,872
	Green River NGCC	0	0	0	0	0	0	0	0	0	0	0	0
2017	Cane Run 7	7,848	7,848	7,959	7,959	6,648	6,648	7,841	7,841	7,959	7,959	5,952	5,952
	Green River NGCC	0	0	0	0	0	0	0	0	0	0	0	0
2018	Cane Run 7	8,209	8,209	8,324	8,324	7,319	7,319	8,189	8,189	8,324	8,324	6,922	6,922
	Green River NGCC	7,576	7,576	8,323	8,323	5,128	5,128	7,438	7,438	8,321	8,321	4,104	4,104
2019	Cane Run 7	6,827	6,827	7,002	7,002	5,888	5,888	6,736	6,736	7,002	7,002	5,255	5,255
	Green River NGCC	7,389	7,389	8,324	8,324	4,879	4,879	7,069	7,069	8,324	8,324	3,849	3,849
2020	Cane Run 7	7,990	8,345	8,347	8,347	6,530	8,264	7,665	8,343	8,347	8,347	5,705	8,301
	Green River NGCC	6,630	8,346	8,346	8,347	4,117	8,312	5,682	8,346	8,346	8,347	3,074	8,321
2021	Cane Run 7	7,542	7,951	7,958	7,959	5,832	7,916	7,164	7,958	7,959	7,959	5,086	7,920
	Green River NGCC	6,242	8,313	8,319	8,324	3,926	8,276	5,198	8,318	8,321	8,324	2,898	8,258
2022	Cane Run 7	7,239	8,323	8,323	8,324	5,890	8,190	6,481	8,323	8,323	8,324	5,085	8,229
	Green River NGCC	5,070	8,312	8,312	8,324	3,642	8,286	4,022	8,312	8,317	8,324	2,779	8,253
2023	Cane Run 7	5,392	6,672	6,678	6,683	4,471	6,618	4,777	6,678	6,678	6,683	3,670	6,578
	Green River NGCC	5,019	8,323	8,324	8,324	3,920	8,244	4,077	8,323	8,323	8,324	2,976	8,237
2024	Cane Run 7	7,106	8,346	8,347	8,347	5,839	8,280	6,271	8,345	8,347	8,347	4,871	8,266
	Green River NGCC	4,920	8,346	8,347	8,347	3,690	8,269	3,863	8,347	8,347	8,347	2,773	8,263
2025	Cane Run 7	6,781	7,948	7,950	7,959	5,296	7,915	6,095	7,959	7,958	7,959	4,887	7,888
	Green River NGCC	5,302	8,321	8,321	8,324	2,876	8,213	4,022	8,320	8,309	8,324	2,974	8,267
2026	Cane Run 7	7,387	8,302	8,309	8,322	5,675	8,222	6,654	8,317	8,322	8,322	5,553	8,256
	Green River NGCC	5,309	8,310	8,313	8,324	2,320	8,185	4,016	8,323	8,323	8,324	3,130	8,279
2027	Cane Run 7	6,606	7,950	7,942	7,959	4,912	7,881	5,776	7,954	7,945	7,959	4,818	7,864
	Green River NGCC	4,809	8,317	8,290	8,322	2,193	8,160	3,613	8,314	8,308	8,324	2,881	8,247
2028	Cane Run 7	5,831	7,012	7,011	7,026	4,663	6,953	5,187	7,024	7,022	7,026	4,410	6,986
	Green River NGCC	4,569	8,343	8,332	8,347	2,709	8,260	4,281	8,346	8,340	8,347	3,469	8,299
2029	Cane Run 7	6,514	7,958	7,958	7,960	5,444	7,916	5,942	7,959	7,959	7,960	5,031	7,928
	Green River NGCC	2,836	8,322	8,303	8,324	2,347	8,232	3,792	8,321	8,314	8,323	2,988	8,272
2030	Cane Run 7	6,682	8,324	8,300	8,324	5,953	8,243	6,053	8,324	8,304	8,324	5,567	8,251
	Green River NGCC	3,053	8,318	8,300	8,324	2,571	8,263	3,677	8,324	8,322	8,322	3,278	8,284
2031	Cane Run 7	6,277	7,952	7,949	7,959	5,577	7,929	5,577	7,958	7,958	7,959	5,197	7,930
	Green River NGCC	2,934	8,317	8,305	8,322	2,736	8,270	3,486	8,317	8,316	8,318	3,195	8,304
2032	Cane Run 7	6,610	8,339	8,331	8,346	6,102	8,312	5,962	8,346	8,339	8,346	5,674	8,332
	Green River NGCC	3,207	8,329	8,331	8,345	2,841	8,294	3,509	8,343	8,343	8,347	3,231	8,333
2033	Cane Run 7	5,505	6,682	6,682	6,682	5,182	6,662	4,795	6,682	6,682	6,682	4,678	6,676
	Green River NGCC	3,811	8,323	8,294	8,324	2,670	8,278	4,068	8,324	8,323	8,321	3,880	8,317
2034	Cane Run 7	6,478	8,311	8,290	8,324	5,918	8,257	5,698	8,324	8,311	8,324	5,580	8,311
	Green River NGCC	3,255	8,300	8,278	8,324	1,492	8,271	3,616	8,319	8,312	8,324	3,400	8,295
2035	Cane Run 7	6,505	7,949	7,917	7,960	5,609	7,897	5,631	7,960	7,955	7,960	5,447	7,948
	Green River NGCC	3,549	8,312	8,294	8,324	1,806	8,275	3,956	8,324	8,322	8,324	3,626	8,304
2036	Cane Run 7	6,595	8,340	8,312	8,347	6,157	8,288	6,083	8,347	8,346	8,347	5,900	8,319
	Green River NGCC	2,657	8,346	8,320	8,346	1,704	8,319	3,919	8,347	8,347	8,347	3,635	8,337
2037	Cane Run 7	6,037	7,944	7,904	7,953	5,906	7,889	5,661	7,958	7,935	7,958	5,478	7,929
	Green River NGCC	2,168	8,311	8,292	8,324	1,784	8,272	3,910	8,324	8,311	8,324	3,554	8,312
2038	Cane Run 7	5,639	6,986	6,958	7,002	5,274	6,920	4,944	7,001	6,962	7,002	4,804	6,958
	Green River NGCC	2,468	8,323	8,308	8,324	2,224	8,271	4,312	8,321	8,320	8,324	4,037	8,308
2039	Cane Run 7	6,322	7,959	7,933	7,959	5,999	7,909	5,814	7,959	7,959	7,959	5,587	7,955
	Green River NGCC	2,206	8,321	8,270	8,321	1,965	8,256	3,802	8,324	8,323	8,321	3,588	8,316
2040	Cane Run 7	6,960	8,346	8,312	8,347	6,564	8,293	6,180	8,347	8,311	8,347	5,777	8,271
	Green River NGCC	2,411	8,345	8,281	8,345	2,088	8,183	4,221	8,347	8,337	8,347	3,591	8,267
2041	Cane Run 7	6,443	7,921	7,887	7,959	6,037	7,861	5,721	7,960	7,896	7,960	5,008	7,875
	Green River NGCC	2,456	8,312	8,302	8,318	1,980	8,241	4,014	8,324	8,278	8,324	3,179	8,305
2042	Cane Run 7	6,996	8,300	8,282	8,321	6,723	8,266	6,357	8,322	8,298	8,323	5,913	8,236
	Green River NGCC	2,717	8,294	8,288	8,318	2,098	8,213	4,456	8,324	8,321	8,324	3,514	8,210

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 184

Witness: David S. Sinclair

Q-184. Fuel Supply:

a. Please state when the Companies expect to obtain a contract for firm transportation for the proposed Green River NGCC.

b. Please state whether the Companies will issue an RFP for the firm transportation of gas supply needed to supply the proposed Green River NGCC unit. If not: (i) why not?; and (ii) assuming Texas Gas is the entity with which the Companies expect to contract, how can the Companies be certain Texas Gas will not exact a premium price?

c. With regard to CR 7, please identify: (i) the pipeline owner for the gas that will be used to supply the unit; (ii) any and all gas suppliers; (iii) whether the pipeline owner places any restrictions of any type or sort on the access gas suppliers have or may have to the pipeline; (iv) whether the pipeline owner gives any price preference to gas suppliers in any manner affiliated with the pipeline owner.

d. Provide an explanation of the measures and actions the Companies take with regard to procurement of coal contracts, including the RFP process. Explain how this process will or could differ from the process in which the Companies will engage to obtain contracts for the supply of natural gas.

e. Provide a detailed explanation and breakdown of all costs the Companies expect to incur with regard to fuel supply for both CR 7 and the proposed Green River NGCC unit. Include an explanation of how the Companies intend to recover each such cost.

f. Provide an explanation of how the Companies intend to pass along the costs for fuel supply for both CR 7 and the proposed Green River NGCC unit through the Fuel Adjustment Charge. Include in your explanation a discussion of regulatory filings with the Kentucky Public Service

Commission, and any changes to how those costs will be reported in customer bills.

g. With regard to CR 7, please identify and provide copies of any and all hedging contracts the Companies have procured. If none, please identify any and all plans the Companies have or may have to procure any such contracts, and the process(es) by which such contracts will be procured.

h. With regard to your response to subpart (g), above, do any or all of those contracts identified therein differ from any hedging contracts LG&E has in place regarding the supply of gas used for its LDC operations? Please explain in detail.

i. With regard to the proposed Green River NGCC unit, please identify and discuss any and all plans the Companies have or may have to procure any gas hedging contracts, and the process(es) by which such contracts will be procured.

j. Please provide copies of any and all reports, studies, analyses or projections regarding the use of hedging of gas fuel supplies for both the proposed Green River NGCC unit and CR 7.

k. Please provide copies of any and all studies regarding risk analysis the Companies either conducted, or which any external consultants or other entities conducted on the Companies' behalf, pertaining to the use of natural gas as a fuel stock.

A-184.

a. See the response to Question No. 52(k).

b. There are only two pipelines that could supply Green River NGCC so no RFP is required. See the response to AG 1-52(k). The rates of interstate pipelines such as Texas Gas Transmission ("TGT") are regulated by the Federal Energy Regulatory Commission based on their cost of providing service.

c. (i) The interstate gas pipeline that will interconnect with the CR 7 pipeline is owned and operated by the Companies is TGT.

(ii) TGT is an "open access" interstate transporter that offers firm and interruptible gas transportation and storage services as well as balancing services, but does not offer commercial gas sales service. (*See* the FERC Gas Tariff, Fourth Revised Volume No. 1, of Texas Gas Transmission, LLC.) Attached is a list of suppliers that the Companies have Master

Agreements with to purchase gas as well as additional suppliers that currently do business on TGT.

(iii) Under FERC's "open access" transportation rules, TGT is required to provide all service "without discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind." See 18 CFR Section 284.7 (2013).

(iv) TGT is also subject to FERC rules that prohibit it from affording any preference, or from engaging in communications or other activities that would effectively afford a preference, to any affiliated entities that are engaged in gas commodity activities. FERC's Standards of Conduct for Transmission Providers are found at 18 CFR Part 358 (2013).

d. Attached is a copy of the Companies' "Fuel Procurement Policies and Procedures" that has previously been provided to the Kentucky Public Service Commission which describes the measures and actions taken to procure coal. This document already covers the procurement of natural gas and will be updated to reflect additional procurement activities related to a NGCC plant that are similar to the activities for a coal plant.

e. As is the case with the Companies' existing SCCTs, they expect to incur costs for gas transportation and gas supply. Just as with the SCCTs, the Companies expect to collect these costs through the Fuel Adjustment Clause.

f. The Companies do not anticipate any changes to their current Fuel Adjustment Clause process when Cane Run 7 and Green River NGCC become operational. Similarly, no changes will be required to collect these costs on customer bills.

g. The Companies have not entered into any "hedging" contracts related to Cane Run 7 and have no plans to do so in the future. At some point, the Companies may enter into long-term physical supply contracts just as they currently do with coal suppliers and in accordance with the "Fuel Procurement Policies and Procedures." See the response to subpart (d).

h. The Companies have not entered into any "hedging" contracts.

i. See the response to subpart (g).

j. The Companies have no such reports, studies, analyses or projections.

k. The Companies have not conducted any studies or risk analysis of the type described in this question. However, the Companies subscribe to numerous industry and government publications that discuss developments in the natural gas markets.

Natural Gas Suppliers

The Companies has executed NAESB or GISB Master Agreements with the following 49 natural gas suppliers as of March 19, 2014.

Anadarko Energy Services Company
BG Energy Merchants, LLC
BP Energy Company
Central Crude, Inc.
Chevron Natural Gas
Citigroup Energy, Inc.
Concord Energy LLC
Dominion Exploration & Production, Inc.
EDF Trading North America, LLC
Energy America, LLC
Eni USA Gas Marketing LLC
ETC ProLiance Energy, LLC
Gavilon, LLC
J.P. Morgan Ventures Energy Corp.
Laclede Energy Resources, Inc.
Marathon Oil Company
MIECO, Inc.
NJR Energy Services Company
Sempra Midstream Services, Inc.
Shell Energy North America (US), L.P.
Southwestern Energy Services Company
Tennessee Valley Authority
Triad Hunter, LLC
United Energy Trading, LLC
WPX Energy Marketing, LLC
Atmos Energy Marketing, LLC
BNP Paribas Energy Trading GP
Castleton Commodities Merchant Trading
Chesapeake Energy Marketing, Inc.
CIMA Energy, LTD
Colonial Energy, Inc.
ConocoPhillips Company
DTE Energy Trading, Inc.
Enbridge Marketing (U.S.) L.P.
Energy USA, TPC Corporation
EQX Ltd.
Exelon Generation Company, LLC
Hess Corporation
JLA Energy, LLC
Macquarie Energy, LLC
Marathon Petroleum Company, LP
National Energy & Trade, LP
Oneok Energy Services Company, LP
Sequent Energy Management, L.P.
Southeast Natural Gas
Tenaska Marketing Ventures
Total Gas & Power North America, Inc.
Twin Eagle Resource Management, LLC
Vitol Inc.

These additional 18 producers and/or marketers are active on the Texas Gas Transmission pipeline but do not presently have Master Agreements with the Companies.

Adams Resources
BP Canada Energy Marketing Corp.
CNE Gas Supply LLC
Crosstex Gulf Coast Marketing, Inc.
EOG Resources
Integrys Energy Services, Inc.
Repsol Energy North America Corp.
Stand Energy Corp.
TEXLA Energy Management, Inc.
BHP Billiton Petroleum, LLC
Centerpoint Energy Services, Inc
Concord Energy LLC
Cross Timbers Energy Services, Inc.
Gant Energy Management
NextEra Energy Power Marketing, LLC
Spark Energy Gas, LP
Tennergy Corp.
Wells Fargo Commodities, LLC

FUEL PROCUREMENT POLICIES AND PROCEDURES
Louisville Gas and Electric Company
Kentucky Utilities Company

A. Definitions:

1. "Agreement" means a legally binding document, in which one party agrees to sell and the other agrees to buy Fuel or Transportation Services for Fuel, fully executed by both Buyer and Seller.

2. "Authority Limit Matrix" – The Authority Limit Matrix (ALM) is a Company policy to be used in combination with the more detailed policies and procedures, indicating the minimum authority required for specific transactions. Its purpose is to provide an easy accessible source of information with respect to the approval process of LG&E and KU Energy LLC (LKE or the Company).

3. "Award Recommendation" means the Company's internal approval process for the review and approval by Management of a recommended Fuel purchase and/or Transportation Services agreement.

4. "Chief Operating Officer" means the Company's principal officer responsible for business operations.

5. "Company" means Louisville Gas and Electric Company (LG&E) or Kentucky Utilities Company (KU) or both.

6. "Contract" is an Agreement for Fuel supply or Transportation Services with a fixed term typically in excess of one year.

7. "Contract Purchase" means any purchase of Fuel or Transportation Services by the Company where the terms and conditions are incorporated in the Contract, typically more than one year's duration.

8. "Director" means the Company's Director of Corporate Fuels and By-Products.

9. "Department" means the Company's Corporate Fuels and By-Products Department.

10. "Distressed Coal" means a limited amount of coal which may be purchased at a price below the current market price of similar quality coal.

11. "Emergency" means extraordinary conditions affecting Fuel production, transportation, or usage; including, but not limited to strikes, lockouts or other labor problems, embargoes, mining impediments, extreme market conditions and other problems affecting the production or transportation of Fuel, existing and/or forecasted extreme weather conditions, or any other conditions or circumstances that can be reasonably foreseen as impairing the continued supply of Fuel to the Company.

12. "Environmental Standards" mean the legal requirements for compliance with emission levels or other environmental protection requirements applicable to one or more of the Company's generating Units.

13. "Formal Solicitation" means the process of soliciting sealed bids for the supply of Fuel and/or Transportation Services.

14. "Fuel" means coal, fuel oil, or natural gas purchased by the Company for one of its generating stations.

15. "Informal Bid" means the process of considering unsolicited or solicited oral or written bids for Fuel purchases and/or Transportation Services.

16. "Joint Contract" is any contract that is written to supply Fuel and/or Transportation Services to both LG&E and KU. The allocation of fuel under a Joint Contract should be made pursuant to Section D.8. below.

17. "Purchase Order" is an Agreement for the supply of Fuel and/or Transportation Services with a term of typically one year or less.

18. "Sarbanes-Oxley" means the Sarbanes-Oxley Act of 2002 (also known as the Public Company Accounting Reform and Investor Protection Act).

19. "Spot Purchase" means any purchase of Fuel and/or Transportation Services by the Company where the terms and conditions are incorporated into a Purchase Order or Contract with a term typically of one year or less.

20. "Station" means one of the Company's generating stations.

21. "Supplier" means the seller who is a party to an Agreement and is obligated to comply with the Agreement's terms.

22. "Transportation Services" means the mode(s) of moving fuel from the point of purchase to the receiving station, including all related costs and activities (owned/leased equipment, maintenance and repair, barge fleeting services, blending, transloading, etc).

23. "Unit" means a generating unit at a Station.

24. "Vice President – Energy Supply and Analysis" means the Company's principal officer to whom the Director of Corporate Fuels and By-Products reports and who in turn reports to the Chief Operating Officer.

B. <u>Fuel Procurement Policies:</u>

The Company's Fuel Procurement Policies and Procedures define the process to obtain an adequate and reliable supply of Fuel of sufficient quality that yields the lowest possible cost of electrical energy delivered to the Unit bus bar, consistent with the Company's obligation to provide adequate and reliable service to its customers, to meet operational and Environmental Standards, and to meet any other applicable legal requirements. The Company will use its best efforts to secure its Fuel supply at competitive prices through the use of the Formal Solicitation, Informal Bid, and negotiation process as described in this document. The awarding of Contracts and Purchase Orders will comply with internal business controls including the Authority Limit Matrices, Sarbanes Oxley compliance and Internal Audit Services' recommendations. The Company has detailed internal control procedures covering Contract Management, Receipt of Goods and Payments (including weighing, sampling, and invoice payment), and Coal Inventory (includes Stockpile Surveys).

Implementation of this policy is of highest priority to the Company. The Director of Corporate Fuels and By-Products will review the Company's Fuel Procurement Policies and Procedures annually and update the policies as appropriate. The Corporate Fuels and By-Products Department shall be organized and staffed, and Fuel procurement procedures and administration shall be conducted, in an efficient and practical manner consistent with this policy. Fuel shall be purchased at competitive prices considering all material factors, including, but not limited to, quantity needed to maintain an adequate inventory, quality required to meet operating characteristics and Environmental Standards, resulting bus bar energy costs, reliability of the Supplier, diversity of Suppliers, diversity of fuel transportation modes, and meeting Emergency or other unusual circumstances affecting market conditions.

C. <u>Organization</u>:

1. <u>Department Structure.</u> The Department shall be organized and staffed to effectively administer the Company's Fuel procurement function.

2. <u>Organizational Responsibility.</u> The Director is responsible for the operations of the Corporate Fuels and By-Products Department and reports to the Vice President – Energy Supply and Analysis who is responsible for the Energy Marketing and Fuel Procurement functions. The Vice President - Energy Supply and Analysis reports to the Chief Operating Officer who has the final responsibility for Fuel procurement. Other Departments may be utilized by the Corporate Fuels and By-Products Department to the extent the Director, Vice President – Energy Supply and Analysis, and/or Chief Operating Officer consider advisable in the execution of the functions of the Department.

3. <u>Approval Authority (Award Recommendation).</u> An Award Recommendation will be prepared for all Agreements for the purchase of Fuel and Transportation Services. The Award Recommendation will be signed (as a minimum) by the Department's Fuel Contract Administrator, Manager LG&E and KU Fuels, Director of Corporate Fuels and By-Products, Plant Manager(s) of the Plant(s) that is (are) to receive the Fuel and/or Transportation Services, and the Vice President – Power Production. Additional signatures may be required in accordance with the following Authority Limit Matrices:

Position	Maximum Term	Maximum Tenor	Maximum Notional $ Amount
Manager LG&E and KU Fuels	1 year	2 years	$10,000,000
Director, Corporate Fuels and By - Products	1 year	2 years	$10,000,000
Vice President, Energy Supply and Analysis	3 years	4 years	$20,000,000
Chief Operating Officer	5 years	6 years	$25,000,000
LG&E and KU Energy LLC, Chief Financial Officer and Chief Executive Officer			$180,000,000
LG&E and KU Energy LLC Investment Committee; LG&E and KU Energy LLC Board			Over $180,000,000

4. Reports. The Director will instruct the Department to prepare, maintain and distribute various reports to management and others as deemed necessary for business operations and regulatory requirements.

5. Records. The Department shall maintain the following records:

a. Open Files. The Department shall maintain within the Department's office area, the following files for at least one year or longer as the Contract term or other conditions warrant:

(1) For each current Contract Supplier, Spot Purchase Supplier, or Transportation Services Provider, the files will contain:

(a) Contract documents, amendments, Purchase Orders and escalation documentation;

(b) General correspondence;

(c) Invoices and invoice verification data;

(d) Delivery records and quality analyses data;

(e) Field inspection reports and other data.

(2) A record of transportation units (railroad cars, barges, etc.) owned or leased by the Company.

(3) A list containing current Suppliers and known potential Suppliers of Fuel.

b. Closed Files. The Department shall maintain its closed files in accordance with the Company's record retention plan.

6. General Administrative Duties.

The Department shall subscribe to trade and industry publications and reports of governmental agencies concerning Fuel, transportation services, market information and prices. The Department shall use its best efforts to keep current on Fuel market conditions, prices and availability, and other developments relating to Fuel procurement.

D. Fuel Supply Procedures:

1. Projections. In conjunction with other departments of the Company, the Department shall prepare an annual projection of Fuel usage and delivered cost for each Station for the number of years required in the Company's planning process.

2. Contract/Spot Mix. Subject to the approvals as set forth herein, the Department shall recommend whether a Contract Purchase is advisable, considering the following factors: (a) the availability of adequate supplies from qualified Suppliers, (b) the need to have an adequate inventory committed for an existing Unit, changes to an existing Unit, or a planned new Unit, (c) the desire to maintain flexibility to market conditions and other factors affecting price and availability, (d) existing and anticipated Environmental Standards, and (e) such other factors as may reasonably affect the implementation of the Company's Fuel Procurement Policy.

3. Current Requirements. The Department shall continually review and analyze the data available to the Department in order to purchase Fuel in a timely manner to meet the requirements of the Company.

4. Supplier Qualifications. The Company shall select potential suppliers on the basis of the current supplier list, performance on past and current Fuel Contracts, market intelligence from industry research, and general knowledge of the industry. No potential qualified supplier shall be preferred or discriminated against because of race, religion, color, sex, age or marital status of the supplier or any of its representatives.

   The supplier list is periodically reviewed by the Department to eliminate any suppliers that are known to have gone out of business and to also add any new or existing suppliers that were previously not on the supplier list. The Department not only reviews the membership lists of several coal associations (for example the Lexington Coal Exchange, the North Carolina Coal Institute, the American Coal Council, the National Mining Association, etc.) for new suppliers to add to the supplier list, but also adds new suppliers based upon field inspection visits. If a supplier is identified that is not on the current supplier list, the Department will add the supplier to the list for the next RFQ. Suppliers can be added to the supplier list either by request of the supplier or by the Department.

   A notice of a Request for Quotation (RFQ) is published in several Coal Industry Newsletters. The RFQ is initially sent to the suppliers on the current supplier list and posted on the Company website. If a supplier that has not received the RFQ calls and asks to be put on the Department's supplier list they are automatically added to that list and a copy of the RFQ is sent to that supplier. During the evaluation of the bids, if a new supplier has submitted a bid that is competitive, a new supplier evaluation will be performed to determine the capability of the supplier.

The supplier evaluation is done to determine if a supplier has the ability to deliver the quantity and quality of coal bid at the offered price. An actual site visit may be conducted. The information requested is based upon:

- The volume and term requested in the RFQ

- Past experience the Company has with the supplier

- The size and financial stability of the supplier

- Past experience the Company has with the type coal being offered

- Previous knowledge the Company has concerning the source operation (possibly under a different source name)

The data requested may include coal reserve data such as property maps and drill logs, mining plans, listing of all production equipment, coal preparation facilities such as coal preparation plants, sampling and analysis capabilities on site, mine staffing and organization, past production records, and status of permits. In addition, financial data will be requested and a supplier credit assessment will be performed in accordance with company policy. If all operational information, financial data, and other results from the site visit evaluation are acceptable, the supplier is approved.

5. <u>Solicitations.</u>

a. <u>Formal Solicitations</u>. The Company shall purchase its Fuel through sealed-bid solicitations. However, the Company reserves the right to request or accept Informal Bids for Fuel purchases as described in Section 5.b., when in its judgment, market conditions or plant conditions provide an opportunity to obtain Fuel more advantageously or more quickly than through the formal sealed-bid procedures. When the Company foregoes the Formal Solicitation process in favor of the Informal Bid procedure (Section 5.b. below), documentation shall be included in the resulting Contract or Purchase Order file describing the conditions.

A Request for Quotation ("RFQ") number will be assigned to each quotation package. The quotation must be returned to the company address as indicated on or before the due date and time, noting on the mailing label the RFQ number. The RFQ number will identify the quotation and ensure the quotation is opened according to the Company's Fuel Procurement Policies and Procedures.

The RFQ package shall contain the following minimum requirements:

- Instructions to Suppliers on the submission of an RFQ, including time and date the bids are due, correct labeling of bid envelope, signatures required, etc.

- Scope of supply Agreement

- Listing of typical information required from Supplier

  Quantity and quality of coal being offered

  Bid Price

  Length of purchase

  Transportation capabilities

  Mining capabilities

- Company terms and conditions

RFQ's shall be opened on or after the established due date and time within the presence of one or more witnesses from another Department. A numbered log shall be kept for logging in the receipt of each sealed envelope. This numbered log shall be signed by the witnesses noting the bids were all sealed prior to opening and were received prior to the due date and time. Those bids received after the designated time will be returned unopened to the bidder, unless the Director waives this provision.

Upon opening the sealed envelopes, each bid shall be given the log number assigned to it and initialed by the witnesses attending the bid opening.

All candidates shall be given the same opportunity and time frame to respond to the RFQ. Information clarifications shall be shared with all candidates. A copy of the RFQ and the original of the Suppliers' bid documents with evidence of the witness signatures shall be maintained within the Department.

The Department's Fuel Administrator is responsible for entering the bid data into the bid evaluation spreadsheet. The spreadsheet contains data fields such as:

Supplier's name (from bid)

Mine name and location (from bid)

Fuel loading point, river milepost or rail loadout (from bid)

Annual price in dollars per ton and cents/MMBtu (from bid)

Transportation cost (assigned by the Fuel Administrator)

Calculated total delivered cost (calculated by the Fuel Administrator)

Fuel technical specifications, such as:

BTU per pound

Sulfur content

Moisture content

Ash content

Chlorine content

Size

Arsenic content

Hardgrove Index

Other technical specifications as appropriate

The bids are secured in the Fuels Procurement area.

The Department's Manager LG&E and KU Fuels will independently verify that all bid data is correctly entered into the bid evaluation spreadsheet.

b. Informal Bids. When, in the Company's judgment, Fuel can be obtained more advantageously or quickly for a particular plant through the Informal Bid procedures, the Department may solicit offers or accept unsolicited offers from Suppliers by telephone, electronic mail, facsimile or otherwise. Although these bids are typically used for Spot Purchases, circumstances may arise that would justify the recommendation of a long-term Contract from an Informal Bid process. The award recommendation for all such Informal Bid purchases shall include the Department's Fuel Sole Source Award Recommendation form with appropriate signatures.

6. Contract Awards. The Department shall review and analyze each Contract offer. The evaluation will include, but not necessarily be limited to, the items required by the Company to satisfy operational, Environmental Standards and economic criteria. Based upon the bid evaluation spreadsheet, the Department will evaluate and rank all quotations received by total delivered cost and lowest evaluated cost of electrical energy delivered to the Unit busbar. Other factors may be considered, including but not limited to, ranking reports generated by a software model that evaluates the impact of different coal qualities on Unit bus bar costs, supplier credit assessment, supplier past performance, diversity of region of supply, diversity of transportation mode, and diversity of suppliers. From this ranking, a short list of bidders may be selected from which the Department intends to conduct further discussions and/or negotiations. The short list may include unsolicited offers. The size of the short list will be determined solely at the

Department's discretion. The Department may engage in preliminary negotiations with Suppliers on the short list to determine which offers warrant further consideration. The objective of the negotiations shall be to reach Agreements with Suppliers that provide the Company with favorable terms and conditions, the lowest possible cost of electrical energy delivered to the Unit bus bar and reliable supply consistent with other qualifiers related to supplier reliability, existing and future Environmental Standards, transportation options, etc. A team may be formed to conduct negotiations with bidders on the short list. Generally, this team will consist of two or more representatives from the Department. The terms and conditions outlined in the quotation submitted to the Department by the bidder shall be the basis for beginning negotiations with each potential Supplier. A representative from the Legal Department shall review documents regarding terms and conditions.

The Department may in some instances perform investigations of the bidders to determine their ability to supply Fuel under the terms and conditions outlined in their proposals. These investigations may include site visits, mine operation audits, audits of financial information, test shipments, or other similar actions intended to determine the bidder's qualification as a Supplier. The Department shall verify the adequacy of the proposed source of supply for coal quantity and quality.

The recommended Supplier(s) shall be selected by the negotiating team based upon the evaluation criteria and the results of the negotiations. The Department's Fuel Administrator will prepare the contract Award Recommendation for approval as detailed in Section C.3. This recommendation will document the selection criteria and pertinent factors, and in circumstances where more than one company is selected, the recommendation shall describe the tonnage requirements and other responsibilities of each of the other recommended Suppliers.

7. <u>Spot Purchases.</u> Spot purchases may be made by the Company subject to the limit of authority stated in section C.3. In instances where there exists an opportunity to purchase Distressed Coal or other coal from an Informal Bid, the Manager LG&E and KU Fuels may recommend the purchase of such coal to the Director without soliciting proposals through the Formal Solicitation process. The Award Recommendation for all such Fuel purchases shall include the Department's Fuel Sole Source Award Recommendation form with appropriate signatures.

8. <u>Joint Contracts.</u> Joint Contracts shall be made at the discretion of the Department in order to capture economic benefit from the combined purchasing power of LG&E and KU. Such discretion will be based upon the Company's operating requirements, Environmental Standards, inventory levels, and the ability of the Company's power plants to burn similar fuels.

9. <u>Documentation.</u> Contracts and Purchase Orders shall be signed by the Supplier and the Company.

   The following documents must be maintained:

   - The final list of bidders
   - A copy of the bid package

- The bidders' responses with witnesses' signatures
- The bid evaluation summary

E. Fuel Supply Agreement Administration:

1. Compliance. The Department shall review and analyze daily business and operational reports to properly administer all Fuel and Transportation Services Agreements. Coal weighing and sampling is conducted at each individual power plant site. Coal weights are measured in accordance with industry-accepted methods. Coal sampling and analysis is performed in accordance with Generation Services' System Laboratory procedures. These procedures have been developed in accordance with ASTM standards and cover coal sampling, coal sample preparation, coal sample identification, handling and shipping, and coal analysis on a parameter-by-parameter basis. Coal quantity and quality are reported to the Department through Aligne (the fuels management system).

2. Amendments. A Contract/Purchase Order shall not be materially amended except after analysis by the Department, recommendation of the Director, review by the Legal Department and in accordance with the Authority Matrices in C.3.

3. Contract Administration. The Department shall maintain the necessary data to administer the Contracts. Every Supplier's request for a change outside the existing terms, conditions, or prices must be written and supported by adequate data in conformity with the Contract. Each request shall be analyzed by the Department against the Contract provisions, and reported with recommendations to the Director. If the parties do not come to agreement on the new terms, negotiations between the Supplier and Company, as dictated by the Contract's terms, shall be the primary method of resolving the issue.

4. Supplier's Relief. Any Supplier's request or claim for relief from compliance with any provision of the Contract's terms such as Force Majeure conditions, quality specifications, approval of alternate sources, etc, must be in writing with an adequate description of conditions warranting nonperformance. Each request or claim shall be reviewed by the Director and the Company's Legal Department.

5. Inspections. The Director shall cause inspections of mining and other facilities of a Contract coal Supplier or other Fuel supply facilities as part of Contract Administration.

6. Emission Allowance Management. All allowances offered in connection with supplying fuel for either LG&E or KU generating Units will be managed in accordance with the Company's environmental, utility accounting, and rates and regulatory policies and procedures. The appropriate way to accommodate any additional allowances (offered in conjunction with supplying fuel) will be dependent on the quantity and vintage of the allowances offered.

F. Fuel Supply Agreement Enforcement:

1. General Enforcement Policy. Supplier obligations under Fuel supply Agreements shall be enforced by the Company to ensure Supplier compliance with the Company's overall procurement policy and to provide for the continuing supply of Fuel.

2. Department Responsibility. Whenever it is determined that a shipment does not meet the Fuel Supply Agreement terms or a Supplier is not complying with the Fuel Supply Agreement terms, the Department shall inform the Supplier and direct that subsequent shipments be in compliance.

G. Legal Assistance:

The Department shall have access to, and may receive advice from, the Legal Department on all matters relating to Fuel procurement, administration and enforcement.

H. Inventory Levels:

The Company has an obligation to ensure the availability of continuous reliable service to its customers. Decisions affecting Fuel inventory shall be responsive to this obligation.

The Company strives to maintain an adequate inventory to ensure service reliability while allowing for enough flexibility so inventory levels can be responsive to known and anticipated changes in conditions and minimize the risks of unforeseen conditions. Inventory ranges are established based upon forecasted plant utilization, deliverability risks related to availability of truck, rail and barge capacity and associated transportation infrastructure, fuel quality requirements of the plants, the position of the plant in the dispatch order, risk of market supply-demand imbalance, and the ability to conduct quick spot market transactions. The general level of inventory is adjusted to meet anticipated conditions (i.e. summer/winter peak load, river lock outages, Unit outages, fuel unloading system outages, etc).

Coal inventories are reported monthly in the Department's Monthly Fuels Management Report. Regular inventory reports are made to senior management and inventory is reviewed by the Enterprise Risk Management Committee to ensure compliance with internal policies.

I. Emergency Procurement:

Any one or more of the procedures described herein may be waived by the Vice President - Energy Supply and Analysis, whenever, Fuel must be purchased due to extraordinary conditions such as strikes, lockouts or other labor problems affecting Fuel production or transportation, embargoes, mining or other problems affecting production or transportation, existing and/or forecast extreme weather conditions, or any other conditions or circumstances that can be reasonably foreseen as impairing the continued supply of Fuel to the Company. When such a purchase is made, documentation of circumstances will be included in the Contract or Purchase Order file.

J. <u>Transportation Services Contracts:</u>

Transportation Services bids shall be requested and Contracts negotiated whenever appropriate. A tariff may be used in lieu of a Contract Agreement if conditions warrant. Consideration shall generally be given to the following factors when considering the need or desirability to make a Transportation Services Agreement:

- plant requirements;
- the locations of potential Fuel Suppliers;
- the most desirable transportation modes available;
- coal unloading and handling system constraints;
- existing transportation routes and transfer points between Suppliers and Company generating Stations;
- desirability of maintaining flexibility with different modes of transportation;
- economics;
- other factors which may affect the delivery of Fuel to the Company's generating Stations.

The process of selecting and contracting for Transportation Services will vary with the mode of transportation being sought. For barge and truck deliveries, the Department will generally use the Company's accepted competitive bidding procedures. In instances where only one rail carrier may serve a plant, direct negotiations with the rail carriers serving a particular coal source may be initiated.

The selections of a transportation Supplier will generally be based upon, but not necessarily limited to, cost, reliability, coal unloading and handling system constraints, and other factors. Transportation Service Agreements must be in writing and signed by all parties, unless provided under an approved tariff. The approval procedures set forth in Section C.3 shall be used for the approval of all Transportation Contracts.

K. Other Fuels/Bulk Commodities/Service Contracts:

Bulk Commodity Supplies (including, but not limited to scrubber reagent, ammonia, hydrated lime, Trona and activated carbon) to be used by the Company's generating Stations and laboratory services, weighing and sampling services, stockpile surveys, governmental imposition claims assessment and coal pricing information services shall be requested and Contracts negotiated by Fuels, whenever appropriate. Associated transportation services related to Section J. such as railcar leases, railcar maintenance and repair, barge maintenance and repair, barge fleeting services, coal blending, and coal transloading services shall also be requested and Contracts negotiated by Fuels whenever appropriate. All of these Bulk Commodity/Service Contracts will abide by the Approval Authority Limits as set forth in Section C.3. above.

Natural Gas. Natural gas is procured on an "as-needed" basis due to the unpredictability of use. The need for natural gas fired generation is determined by many real-time variables; including, but not limited to, weather, customer demand, generation availability, transmission availability, and market prices. Purchases of natural gas are typically conducted in the day-ahead or intra-day spot market. The Power Supply Department is responsible for the purchase of natural gas and associated pipeline transportation.

Fuel Oil. Fuel oil is procured on an "as-needed" basis due to the infrequency of use of this Fuel and the nature of the oil market. The responsibility for fuel oil procurement varies. When the need for fuel oil arises, the Department and/or the Power Plants will solicit vendors for offers. Orders are assigned on the basis of lowest delivered cost and the ability to fill the order. Solicitation results are documented in the Department for purchases made by the Department.

L. Affiliate Transactions:

Transactions and relationships between the Company and its unregulated affiliates are governed by four governmental agencies: the Kentucky Public Service Commission, the Federal Energy Regulatory Commission, the Securities and Exchange Commission, and as regards Kentucky Utilities Company, the Virginia State Commission.

The Company may purchase coal from an affiliate at the lesser of cost or market, if such a transfer is reasonably required by the Company to meet an Emergency and the Company believes in good faith that, under the circumstances, the transaction will be to the advantage of the Company. At the time of the affiliate transaction, the Company will document through the award recommendation process, the pricing basis and the justification for the affiliate transaction. The Company shall report any such purchase in its next recurrent report due to the Commission (Form A or Form B filing, or their successor(s)). All such affiliate transactions must as a minimum, meet the requirements of the Affiliate Transaction Overview, dated May 26, 2003, including the requirements of Kentucky Revised Statutes Chapter 278, Kentucky Public Service Commission Sections 2201 through 2219; the Securities and Exchange Commission, Title 17 – Commodity and Security Rules, Part 250 – General Rules and Regulations; and Virginia State

Corporation Commission, Code of Virginia Title 56 – Chapter 4 and any other applicable affiliate transaction rules.

M. Ethics and Conduct:

The Company recognizes the importance of following the Company's Standards of Integrity to guide the conduct of the Corporate Fuels and By-Products Department in the performance of its duties and responsibilities:

The Department shall endeavor to serve the best interests of the Company and its customers in the performance of the Department's duties and responsibilities.

Fuels staff shall adhere to the ethical standards and policies of the Company.

Each employee involved with the procurement of Fuel will be required to promptly disclose, in writing, any actual or potential conflicts of interest to their supervisor and the LG&E/KU Compliance Department.

N. Penalties For Noncompliance

All Fuels employees are required to familiarize themselves with the Fuels Policies and Procedures and acknowledge through a process established by management, that they have received, read, understand, accept, and will act in accordance with this document. Failure to comply with any term of the policy may result in disciplinary action, up to and including discharge.

Key Contact: Manager - Fuels Accounting and Administration

References: Authority Limit Matrix, Records Management and Retention Policy, Standards of Integrity, Reliability Standards, and Affiliate Restriction Regulations

Administrative Responsibility: Director, Corporate Fuels and By- Products

Originally issued at Louisville, Kentucky, the 10th day of February, 2003.

Revised effective March 1, 2013.

Louisville Gas and Electric Company

Kentucky Utilities Company

By______________________________
Paul Thompson
Chief Operating Officer

By______________________________
David Sinclair
Vice President – Energy Supply and Analysis

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 185

Witness: John N. Voyles, Jr.

Q-185. Proposed Transmission Upgrades:

a. Explain whether the proposed transmission improvements will in any manner enhance the Companies' interconnections with any other utilities, transmission owners, ITOs, electric generation providers, or RTOs, including TVA. Explain in complete detail.

b. Provide a discussion of what role, if any, the Companies' OATT will have on the costs of the proposed upgrades.

A-185.

a. Until such time the studies from the Companies' ITO are completed as required by the Companies' OATT, it is not known if the proposed transmission improvements will enhance the interconnections. However, there are existing tie lines between KU and TVA and between KU and MISO in the area of the Green River generation station that could require upgrades. If upgrades of these tie lines are identified and required by the OATT studies then the upgrades may result in larger transfer capabilities between these companies or generation providers.

b. The Companies' OATT defines the study processes for generator interconnections that must be performed by the ITO. Once completed, the studies define the necessary upgrades to be estimated and constructed.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 186

Witness: Edwin R. Staton

Q-186. Provide a detailed description of the assumptions and inputs used in the Companies' most recent IRP filing, and compare them with the assumptions and inputs utilized in the joint load forecasts for 2012, 2013, and the most recent joint load forecast.

a. Based on the Companies' response to AG 1-20 in Case No. 2014-00003, the Companies will in the next few business days be filing their most-recent IRP. Will the Companies agree to supplement their response with the latest information available from this forth-coming IRP? If not, why not?

A-186. The Companies most recent IRP filing and any future IRP filing, including the assumptions and inputs used in those filings, are available to the AG on the PSC website. The referenced joint load forecasts are also available to the AG. Therefore, the documents necessary for the requested comparison are available to the AG and no supplement is necessary.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 187

Witness: David S. Sinclair

Q-187. Provide copies of any and all studies, projections or analyses regarding how the construction of both the proposed Green River NGCC and the proposed Brown Solar Facility will affect price elasticities of demand regarding residential, commercial and industrial classes.

A-187. The price elasticity of demand is defined as the percent change in quantity demanded divided by the percent change in price. The construction of either of these units will not impact customers' demand response to a change in price.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 188

Witness: David S. Sinclair

Q-188. Explain whether the colder-then-normal temperatures experienced in the Winter of 2013-2014 will or may cause one or both the Companies to become either a winter-peaking or dual-peaking utility, and if so, for how long into the future.

A-188. The KU system has historically had a winter peak and summer peak that are very similar due to its large number of residential heat pumps and the low penetration of gas heating. The LG&E system has a large quantity of customers with natural gas heat as compared to the KU system. Therefore, under "normal" winter and summer weather conditions, the combined system is not forecasted to become winter peaking.

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Case No. 2014-00002

Question No. 189

Witness: Edwin R. Staton

Q-189. Provide separate estimates of the rate impacts if both the proposed Green River NGCC and the Brown Solar Facility are approved and constructed, broken down by ratepayer class. Please provide these estimates based on an average level of monthly consumption.

a. Provide the estimated impact on the average residential customer bill if the application is approved as filed.

A-189.

a. The specific rate impact by ratepayer class cannot be determined at this time since it will be dependent upon a number of variables including timing of rate cases, rate design changes and other financial results affecting future revenues. However, based on the specific revenue requirement for each facility the projected overall revenue increase for each Company would be approximately 3.9% for the Green River NGCC facility and approximately 0.1% for the Brown Solar Facility.

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Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 190

Witness: Edwin R. Staton

Q-190. Provide the retirement dates for each of the following: Cane Run 4, 5 and 6; Green River 3 and 4; and Tyrone 3.

a. Describe: (i) how these plants' net book value have been addressed, including any specific citations to other cases; and (ii) whether they will be addressed in the Companies' next base rate case, and if so, how.

A-190. The retirement date for Cane Run 4, 5 and 6 will be at the time Cane Run 7 becomes operational around April 2015. For Green River 3 and 4, see the response to PSC 1-29. Tyrone 3 has been retired as of February 2013.

a.(i) The plants were reflected in the depreciation study filed in Case Nos. 2012-00221 and 2012-00222 before the Kentucky Public Service Commission. See the Direct Testimony and Exhibits of John J. Spanos.

Tyrone 3 is the only plant that has been retired of those listed. The Tyrone 3 retirement reflecting a net book value of zero was addressed in the Application of Kentucky Utilities d/b/a Old Dominion Power Company for a General Rate Increase in Case No. PUE-2013-00013 before the Virginia State Corporation Commission.

a.(ii) The remaining plant retirements will be addressed in future base rate cases when the retirements occur. The net book value retired will be reflected in future base rate cases.

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Case No. 2014-00002

Question No. 191

Witness: John N. Voyles, Jr.

Q-191. Reference the petition, numerical paragraph 5, wherein it is stated "There are no like facilities in the vicinity of Green River NGCC and it is not anticipated that [it] will compete with any other public utilities, corporations, or persons." Please state whether the Companies are aware that TVA has announced plans to construct a combined cycle gas-fired generation unit in Muhlenberg County having a similar generation output to the Companies' proposed Green River NGCC. Please discuss whether this will in any manner change the statement as quoted above.

A-191. The Companies are aware of the TVA announcement, but it does not change the referenced statement.

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Question No. 192

Witness: John N. Voyles, Jr.

Q-192. With regard to the proposed Brown Solar Facility, state whether the Companies anticipate that, if constructed, the power generated from this facility will constantly be sent into the Companies' transmission system. If not, do Joint Applicants anticipate any future filings in which they seek permission to construct energy storage facilities for the specific purpose of storing the solar-generated power for later distribution?

A-192. The Companies anticipate that the power produced from the Brown Solar Facility will be sent to the Companies' transmission system. No energy storage is currently anticipated as part of the Brown solar project.

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Case No. 2014-00002

Question No. 193

Witness: Edwin R. Staton

Q-193. State whether as a result of the current filing, the Companies anticipate any change with regard to how they handle net metering, and/or in distributed generation, and in particular solar generation provided in which the Companies' own customers participate. Please explain in detail.

A-193. The Companies do not anticipate any change.

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Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 194

Witness: Paul W. Thompson

Q-194. Refer to the Thompson testimony at p. 8, lines 18-21. In the event costs for solar panels, and/or any other plant and equipment necessary to serve the proposed Brown Solar Facility should increase, will the Companies withdraw that portion of its application regarding the Brown Solar Facility? At what point could or would any price escalations make the proposed Brown Solar Facility no longer viable?

A-194. As with any generation resource, if the cost of constructing or operating it becomes untenable and/or inconsistent with Commission precedent for resource planning and not in the best interests of customers, the Companies would take all appropriate action to address the situation. As for a specific "price point" at which the Companies would view the Brown Solar Facility as not being viable, the Companies have not performed such an analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 195

Witness: David S. Sinclair

Q-195. Reference the Sinclair testimony at pp. 12-13. Will the load forecast to be provided in the Companies' next IRP filing, which according to the Companies' response to AG 1-20 in Case No. 2014-00003 will occur in the next few weeks, utilize a different load forecast than either of the forecasts discussed by Mr. Sinclair? If so, will the Companies agree to provide that forecast in the instant case, once it is available?

A-195. No. The load forecast that will be used in the upcoming 2014 IRP filing is the same one described in Mr. Sinclair's testimony on page 12, lines 17-18 as the "2014 LF."

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Response to the Attorney General's Initial Data Requests
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Case No. 2014-00002

Question No. 196

Witness: David S. Sinclair

Q-196. Reference the Sinclair testimony, Exhibit DSS-1 (2013 Resource Assessment), Executive Summary, p. 2.

a. Identify and describe the four scenarios in which the proposed Green River NGCC is not the least-cost alternative;

b. Provide a projection of amounts to be earned from the sale of RECs associated with the Brown Solar Facility, if approved and constructed, over the projected lifespan of that facility.

A-196.

a. See Table 23 in Exhibit DSS-1 at page 29. Only when there is never a GHG limitation on existing generation units <u>and</u> gas prices are at or above the Mid gas scenario would the Green River 2x1 alternative be more expensive than other alternatives, regardless of load level. The Green River 2x1 alternative is not least-cost in the following scenarios:

- Zero CO_2, Mid gas, Base load.
- Zero CO_2, Mid gas, Low load.
- Zero CO_2, High gas, Base load.
- Zero CO_2, High gas, Low load.

b. Revenue from the sale of RECs is dependent on the price of RECs. The table below summarizes the present value of REC revenue over a range of REC prices. The 2016 REC price is assumed to escalate at 2% per year.

2015 REC Price	**PVRR (2013-2042)**
$16 REC	$3 million
$26 REC	$5 million
$57 REC	$11 million
$62 REC	$12 million
$79 REC	$15 million

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Question No. 197

Witness: David S. Sinclair

Q-197. Reference Exhibit DSS-1, Table 7 on p. 12. Confirm that:

a. The three price scenarios provided therein are assumed to be equally likely [as stated on p. 6, § 4.1.2];

b. Under the mid-price scenario, gas prices do not surpass $6.00 until 2022;

c. Under the high-price scenario, gas prices do not surpass $6.00 until 2020; and

d. According to the U.S. Energy Information Administration, natural gas spot prices on March 5, 2014 traded at $6.41/MMBTu, and peaked at $7.90/MMBTu on March 4, 2014. [2]

A-197.

a. The three gas price scenarios were weighted with equal probability in the analysis.

b. Under the mid-price scenario, forecasted <u>annual average</u> natural gas prices do not surpass $6.00/MMBtu until 2022.

c. Under the high-price scenario, forecasted <u>annual average</u> natural gas prices do not surpass $6.00/MMBtu until 2020.

d. According the Energy Information Administration's Natural Gas Weekly Update of March 6, 2014 using Natural Gas Intelligence's Daily Gas Price Index for Henry Hub, the daily settled price of March 5, 2014 for delivery on March 6, 2014 was $6.41/MMBtu. Also, the daily settled price of March 4, 2014 for delivery on March 5, 2014 was $7.90/MMBtu. However, it is important to note that it is not particularly informative to compare the actual natural gas price for a single trading day to a long-term forecast of annual average natural gas prices.

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[2] Source: http://www.eia.gov/naturalgas/weekly/

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Case No. 2014-00002

Question No. 198

Witness: David S. Sinclair

Q-198. With regard to [redacted] proposal to sell its [redacted] plant, did the Companies' analyses included in the instant filing take into consideration the fact that [redacted] will not [redacted]? [3]

a. If so, please state where this can be found in the analyses.

b. If not, please state how this would or could affect the Companies' analyses in the instant filing.

c. If the Companies purchased the [redacted] plant instead of constructing the proposed Green River NGCC, and proceeds with the plan to retire the Green River 3 and 4 units, would the company be able to offset [redacted] SO_2, NO_x, and particulate emissions with the retirement of the two remaining Green River coal units? If not, why not?

d. If the Companies respond in the affirmative to subpart (c), above, did the Companies take this into consideration in their decision making process? If not, why not?

e. If the Companies were to purchase the [redacted] plant, state the savings that would be achieved by not having to obtain an air permit as they would have to do for the proposed Green River NGCC.

f. With regard to the Companies' response to subpart (e), above, did their analysis take any such savings into consideration? If not, why not?

g. Reference Exhibit DSS-1, p. 21 wherein it is stated, "The information presented here reflects each party's best-and-final proposals." State whether the Companies have had any further communications with [redacted]

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[3] [redacted]

regarding any of its proposals since the filing of the application in the instant proceeding.

h. Please provide any counter-offer(s) the Companies may have made to [redacted] regarding any potential purchase of the [redacted] and/or [redacted] plants.

A-198.

a. Yes. The Companies' analysis did not assume that the [redacted] unit would need a new scrubber. [redacted] proposed to sell the [redacted] station to the Companies for $500 million (approximately $1,200/kW). This is the cost at which the proposal was evaluated (see Appendix A of Exhibit DSS-1 at page 49); this cost does not include the cost of a new scrubber.

b. Not applicable.

c. No. The offset is limited to the specific site where the reduction occurs.

d. Not applicable.

e. The Companies have not performed the requested analysis, but all permitting costs were included in assessing a [redacted] purchase and the construction of Green River NGCC.

f. See subpart (e) above.

g. The Companies have not had further communications with [redacted] regarding their responses to the Companies' RFP since the filing of the application.

h. The Companies have not made any counter-offers to [redacted].

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Question No. 199

Witness: John N. Voyles, Jr.

Q-199. Are the Companies aware of any studies regarding the usage of coal combined with iron ore pellets as a fuel for utility generating plants, in an oxidation process? If so, please discuss whether such a process could be used in a coal-fired unit.

A-199. Yes, the Companies are aware of such studies, specifically the work at the University of Kentucky's Center for Applied Energy Research and the Ohio State University. The research is investigating the use of iron oxides in the oxidation of fuel, including coal, for power generation and is referred to as "Chemical Looping." The process oxidizes the fuel and produces a waste stream of carbon dioxide that with minor cleanup might be sequestered without the use of a separate carbon capture technology. The iron oxide is then reduced using oxygen in air to be reused in the oxidation process. While the technology has some potential, it is very early in its development and is not likely to be ready for full scale demonstration until the 2025 to 2035 timeframe. The major areas of research include oxygen carrier (iron oxides) development to improve performance/reduce cost and overall process design.

It is important to note that the concept for this technology would not be an application likely to be retrofit on an existing pulverized coal unit. If successful, the concept would replace the conventional boiler technology.

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Question No. 200

Witness: David S. Sinclair

Q-200. Reference the following statements in Exhibit DSS-1: (i) [redacted] unfavorable to the Green River 2x1 alternative (over all scenarios)" [at p. 25]; and (ii) "In a CO2 constrained world, the efficiency of gas technologies is important. The improved heat rate of the Green River 2x1 alternative (compared to the [redacted] alternative) more than offsets the higher capital cost for the Green River 2x1 alternative" [at p. 26].

a. Did the Companies' modeling consider any scenarios in which an [redacted] was modeled on the basis of converting the facilities to a combination of 2x1 and/or 3x1 units to be scaled-up to an output that would approximate that of the proposed Green River NGCC? If so, state where in the filing this information can be found. If not, why not?

b. Describe how any such conversion of the [redacted] would compare to the proposed Green River NGCC, and any other alternative.

c. Discuss whether any such conversion of the [redacted] would reduce the heat rate of that facility. If not, why not? If so, describe how this would compare to the proposed Green River NGCC.

d. Discuss the ways in which any such conversion of the [redacted] would change each of the 12 scenarios set forth in the application.

e. Provide any estimates the Companies prepared, or which were prepared under their direction or supervision, regarding cost estimates for a conversion of the [redacted] sufficient to meet the Companies' power needs.

A-200.

a. No. This scenario was not provided by the bidder.

b. Not applicable

c. Not applicable

d. Not applicable

e. The Companies have not prepared the estimates requested in the question.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 201

Witness: David S. Sinclair

Q-201. In Case No. 2011-00375, the Companies chose to pursue a purchase of the LS Power Bluegrass Facility. Provide a detailed explanation of what has changed since the completion of that case to cause the Companies to now assert that a purchase of those facilities (whether with or without a conversion of those facilities to either 2x1 and/or to 3x1) is not the best option.

A-201. See Mr. Sinclair's testimony on page 31, lines 3-24 and page 32, lines 1-11.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 202

Witness: Paul W. Thompson

Q-202. In the event the U.S. Supreme Court voids the EPA's proposed GHG Rule governing existing power plants, would the Companies be willing to submit an amended application to reflect the changes the absence of any such rule would have on the 12 scenarios set forth in the application? If not, why not? Explain in complete detail.

A-202. To the extent a development occurs that makes the Companies' proposals in this case something other than least reasonable cost, the Companies would take all appropriate actions to do what is in the best interests of their customers. Likewise, as for the specific premature hypothetical raised in this question, the Companies would need to review any such legal decision and make decisions that are in the best interests of their customers.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Attorney General's Initial Data Requests
Dated March 13, 2014

Case No. 2014-00002

Question No. 203

Witness: David S. Sinclair

Q-203. Provide a discussion of the extent to which Joint Applicants have studied, or are willing to study, options to share ownership of power generation plants and/or related infrastructure, including transmission projects, with other utilities based in Kentucky. For example, East Kentucky Power Cooperative will in the next few years require additional capacity, generation or both.

A-203. The Companies provided the RFP to all electric utilities in Kentucky that own or control generation assets. The Companies will do what is in the best interests of their customers. To the extent that the best interests of the Companies' customers are served by exploring the concepts raised in this question, the Companies are open to doing so. In fact, the Request for Proposals process the Companies conducted as described in Mr. Sinclair's Direct Testimony is an example of the Companies' willingness to solicit entities in Kentucky which might have a generation solution that would be advantageous to the Companies' customers.