COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2014 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	**))))**	**CASE NO. 2014-00131**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY
TO THE COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION
DATED NOVEMBER 7, 2014

FILED: NOVEMBER 21, 2014

VERIFICATION

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

The undersigned, **David E. Huff**, being duly sworn, deposes and says that he is Director of Customer Energy Efficiency & Smart Grid Strategy 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 that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David E. Huff

David E. Huff

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

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

My Commission Expires:

July 11, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting 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.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

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

My Commission Expires:

July 11, 2018

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 19th day of September 2014.

Judy Schooler (SEAL)
Notary Public

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

My Commission Expires:

July 11, 2018

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

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Question No. 1

Witness: John N. Voyles

Q-1. Refer to the Integrated Resource Plan ("IRP"), page 5-5, footnote 4. The Companies preserve the option to request an extension that will allow Green River 3and 4 to continue operating. Explain the issues, as they are known, which support keeping the generators operational, or in the contrary, shuttering them.

A-1. LG&E and KU have planned their transmission system to reliably accommodate this generation resource retirement. However, since the filing of the IRP, recent events on LG&E and KU's transmission network and the interconnected utilities have raised concerns over reliability impacts created by the planned retirement of these units and triggered the need for additional study. These recent events include uncertain operations of the expanded Midcontinent Independent System Operator (MISO), recently announced news from Big Rivers Electric Corporation that all three generating units at its Coleman station could be offline for several years, and a real-time electric grid reliability operating condition that occurred in June 2014.

Within the MATS Rule preamble, Section VII.F "Compliance Date and Reliability Issues" provides comments and EPA's response regarding the extension process relative to continued operation of units in order to avoid risk to electric reliability.[1] Specifically, the preamble states:

> "*While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.*"

This preamble discussion is relevant to and consistent with the circumstances at KU's Green River Station. As the NERC registered Planning Authority for the LG&E and KU

[1] 77 Federal Register at 9410/2, February 16, 2012

transmission system, LG&E and KU recently performed a transmission reliability study of the western Kentucky region and have identified solutions that will require a one-year extension for implementation.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 2

Witness: Charles R. Schram

Q-2. Refer to the IRP, page 5-22, Table 5.(3)-2. Confirm the 2014 Percent Growth in Combined Company Summer Peak Demand after demand-side management ("DSM") of 8.4 percent is correct, and if so, the reason(s) it is so much greater than other years.

A-2. The 2013 to 2014 growth in Combined Company Summer Peak Demand after DSM of 8.4 percent is correct. The value for 2013 is the actual peak resulting from a cooler-than-normal summer season, while the 2014 forecasted peak assumes normal weather patterns. Summer weather in 2013 was so mild that the Combined Company peak demand occurred in September instead of the typically warmer months of July or August.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 3

Witness: Charles R. Schram

Q-3. Refer to the IRP, page 5-23, where it states, "As the mining industry continues to struggle, KU's sales in Virginia are forecasted to grow at only 0.1 percent annually from 2014 to 2018." What is the forecasted growth rate for the mining industry from 2014 through 2028?

A-3. The 2014 IRP did not include a specific forecast for the mining industry in Virginia. However, growth rates for Virginia forecasted sales related to mining are largely based on the IHS Global Insight IPI Mining Index. This index was forecasted to grow at a Compound Average Growth Rate (CAGR) of 0.6 percent from 2014 through 2028. However, the decline in mining in recent years has negatively impacted the broader economy in the region, also affecting residential and commercial sales which comprise over 50 percent of the total ODP sales volumes. Together these two rate classes have a forecasted CAGR of only 0.1 percent from 2014 to 2028 in the 2014 IRP.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Question No. 4

Witness: Charles R. Schram

Q-4. Refer to the IRP, page 5-28, where it states, "The Public Authority Sector is projected to decline at a rate of 0.5 percent, primarily driven by one large government related customer." Explain the circumstances surrounding the decline in usage by the one large government related customer.

A-4. Energy sales and billed demand are forecasted to decline over time due to the customer's installation of natural gas and solar generation driven by their long-term goal to be energy independent.

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Question No. 5

Witness: John N. Voyles

Q-5. Refer to the IRP, page 8-2, footnote 2, where it states, "At this time, the Companies have not sought an extension of the compliance date, but are analyzing this option."

a. What is the latest date on which the Companies can seek an extension of the compliance date?
b. By what date do the Companies intend to make a final decision on whether to seek an extension of the compliance date?

A-5.

a. The MATS rule allows for a one-year extension request to be made with the permitting authority up to 120 days prior to the effective compliance date of the regulations. The compliance date in the final rule is April 16, 2015. Therefore, the Companies can request an extension on or before December 17, 2014.

b. The Companies are finalizing the information necessary to request a one-year extension from the Kentucky Division of Air Quality and intend to file the request before December 17, 2014.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Question No. 6

Witness: David E. Huff

Q-6. Refer to the IRP, page 5-38, where it states, "The two years since the approval of these programs has granted greater insight into program modification opportunities. As a result of the lessons learned, the Companies filed Case No. 2014- 00003 with the Commission on January 17, 2014."

a. Explain in detail what is meant by greater insight into program modification opportunities.
b. Describe in detail the lessons that have been learned over the last two years.
c. Identify and explain all best practices found by the Companies due to the greater insight into program modification opportunities and lessons learned.

A-6.

a. The term "greater insight into program modification opportunities" means that the Companies' two years of operational experience have revealed challenges and obstacles associated with several of the programs.

A revised DSM/EE Program Plan was developed, and approved by the Commission, that supports enhancements to current program offerings as a result of program insights and also meet the needs of changing energy-efficiency market conditions. The 2015- 2018 DSM/EE Program Plan included in Case No. 2014-00003 includes enhancements to the following programs that address the lessons learned over the past two years:

- Commercial Load Management/Demand Conservation Program – The Companies saw value in providing load management options for customers beyond compressor based HVAC systems. As such, customizable demand response options to large commercial customers and educational entities while targeting lighting, HVAC, and other equipment that can provide necessary demand savings.
- Residential Incentives Program – To address higher than anticipated customer participation rates, the Companies requested an increase in financial incentive dollars to support customers who purchase various ENERGY STAR® appliances, HVAC equipment or window films that meet certain requirements.

- Commercial Conservation Program / Commercial Incentive Program – To address the feedback and needs of the commercial customer segment the Companies requested to eliminate the on-site commercial audit; further develop its online audit tool as well as additional special-purpose energy tools to support commercial customers; and the Companies seek to rebate for new construction efforts where efficiency is above standard building code.
- Residential Conservation Program / Home Energy Performance Program – To address the needs of the multi-family property owners the Companies requested the addition of a multi-family-property tier and an insulation and weatherization tier.

b. Please see the Companies' response to part a. above.

c. The program modifications and lessons learned described above are a result of operational experience; a DSM Program Review conducted by The Cadmus Group; review of other jurisdictional utilities with similar demographics and supported collaboration with the Companies' DSM Advisory Group. As witnessed in Case No. 2014-00003 Exhibit MEH-2 several examples of the Companies' utilization of industry best practices include: The Home Energy Rebate program partnering with retailers to promote the program and sales of energy-efficient equipment and use of mixed-media marketing. The Home Energy Analysis program utilization of trained, experienced implementation staff to conduct all home energy audits as well as educational materials on recommended measures. The Smart Energy Profile program is using industry-established best practices for behavior change programs. The Residential Demand Conservation program offering incentives for multiple controllable technologies, including central air conditioners, heat pumps, water heater, and pool pumps.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
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Question No. 7

Witness: John N. Voyles

Q-7. Refer to the IRP, page 5-48, where it states, "Additionally, the Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012."

a. What was the remaining life of Brown 1 and 2 as determined by the Brown and Veatch remaining life assessment?
b. Provide a copy of the Black and Veatch remaining life assessment for Brown 1 and 2.

A-7.

a. Assuming that the plant continues to be appropriately operated and maintained, with required renewals and replacements made in a timely manner, Black & Veatch is of the opinion that the Brown Units 1 and 2 may continue to operate in a reliable manner, with nothing indicating that the remaining useful life of either unit is limited in the foreseeable future based on the current condition of the units.

b. Please see attached.

E.W. BROWN UNITS 1 AND 2 REMAINING USEFUL LIFE

BLACK & VEATCH PROJECT NO. 177999

PREPARED FOR

Louisville Gas & Electric and KU Utilities Company

18 JANUARY 2013

BLACK & VEATCH
Building a world of difference.

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1 Executive Summary

1.1 INTRODUCTION

Black & Veatch Corporation (Black & Veatch) was engaged by Louisville Gas & Electric (LG&E) and Kentucky Utilities Company (KU) to provide a remaining useful life (RUL) assessment of the E.W. Brown Units 1 and 2 (Brown Units 1 and 2 or, collectively, the Plant) located in Harrodsburg, Kentucky. This report considers the expected RUL of major Plant components and the Plant as a whole, based on Black & Veatch's engineering evaluation, standard industry experience, and other sources of information. Black & Veatch professionals visited the Plant on October 25, 2012, to perform a visual inspection of the Plant condition and interview Plant personnel.

The E.W. Brown generating station is owned and operated by KU. Brown Unit 1 is a 115 MW gross (107 MW net) sub-critical pulverized coal unit that began commercial operation May 1, 1957, and includes a Babcock & Wilcox boiler and a Westinghouse steam turbine. Brown Unit 2 is a 180 MW gross (168 MW net) sub-critical pulverized coal unit that began commercial operation June 1, 1963, and includes a Combustion Engineering boiler and a Westinghouse steam turbine. Brown Units 1 and 2 are each equipped with low NO_x burners, electrostatic precipitators (ESP), common flue gas desulfurization (FGD) system, and continuous emissions monitoring systems (CEMS).

Specific findings related to Black & Veatch's scope of review for the RUL assessment are presented throughout the remainder of this report. In summary, Black & Veatch's review of the physical Plant and supporting documentation, supplemented by interviews with Plant personnel, indicates that (1) both Brown Units 1 and 2 appear to be in condition that is consistent with the age and technology of the units, (2) the Plant is functionally complete, and (3) Brown Units 1 and 2 have been appropriately maintained and operated.

1.2 ASSUMPTIONS

In order to provide an engineering judgment of the RUL for Brown Units 1 and 2, Black & Veatch has made certain assumptions with respect to future operations. Assumptions in this regard include the following:

- All necessary environmental and other operating permits and licenses will be maintained and Brown Units 1 and 2 will operate in compliance with such requirements.
- Brown Units 1 and 2 will continue to be operated in a manner that is consistent with recent operating practices, with similar number of annual starts and stops and annual generation.
- KU will continue to maintain Brown Units 1 and 2 in accordance with good industry practices, with required renewals and replacements made in a timely manner.

1.3 CONCLUSIONS

On the basis of Black & Veatch's studies, analyses, and investigations of the Plant and the assumptions previously set forth and stated throughout this report, Black & Veatch offers the following opinions:

- The Plant is appropriately staffed for expected future operating requirements, and plant staff is considered qualified to fulfill their operations and maintenance (O&M) obligations.

- The Plant's air quality control (AQC) equipment allows operations within the requirements of environmental operating permits; however, as future environmental regulations may be enacted, KU should monitor the need for environmental retrofits to allow Brown Units 1 and 2 to continue to comply with environmental regulations.
- Good operating procedures and preventive, condition based maintenance programs are effective in mitigating the risk of catastrophic failure that can shorten a plant's useful life. In Black & Veatch's opinion, the Plant has taken appropriate measures to mitigate the risk of catastrophic failure. First, the plant has established and utilizes operating procedures designed to protect the equipment and avoid operating in conditions that would lead to excessive degradation, stress, and wear. Second, the Plant has established a program of preventive and condition-based maintenance in order to identify potential failures and apply the appropriate corrective maintenance. These operating procedures and maintenance programs should reduce the risk of component failure.
- In general, the Plant appears to have adequately defined staff responsibilities, safety programs, work order processes, performance monitoring (through a combination of internal engineering and third party performance monitoring) and predictive maintenance/preventive maintenance procedures.
- The historical O&M expenses are consistent with Black & Veatch's expectations for a plant of this size and type and are considered reasonable, assuming that the Plant continues to operate as it has in the past.
- The Plant was well constructed, is in good condition, and appears to have been well maintained during its commercial operation period. No significant equipment deficiencies have been identified. Although there have been some equipment problems, as discussed in this report, proper measures have been taken to address the problems resulting in subsequent reliable operations.
- Through the course of this analysis, there were no specific issues identified with respect to any major plant components and the overall Plant that would suggest a specific retirement date. The trend in the electric power generation industry for the past 20 years has been to continue to invest in modifications to existing units in order to defer retirement. As a result, there are many units operating today that have exceeded 60 years of operation. Given recent trends in the energy industry, retirement of coal units may be driven by entity-specific considerations other than age and condition, such as economics and environmental aspects, which may have led to the decision to retire units earlier than their physical condition and history of equipment reliability may have supported.
- Although generating units can be retired for a variety of reasons, not all of which may be based solely on condition, analyzing historical industry data provides a reference point for these types of plants. Analysis of industry data for similar units indicates that coal units can be expected to have useful lives ranging as high as 65 to 70 years. In addition, longer lives have also been achieved by similar type units. Assuming that the Plant continues to be appropriately operated and maintained, with required renewals and replacements made in a timely manner, Black & Veatch is of the opinion that the Brown Units 1 and 2 may continue to operate in a reliable manner, with nothing indicating that the remaining useful life of either unit is limited in the foreseeable future based on the current condition of the units.

2 Project Objectives and Scope

The process of evaluating the RUL of the major components at a plant begins with a review of the data characterizing the equipment and the specific company data related to historical and projected future operations. The following sections describe the scope of work and methodology corresponding to this RUL assessment.

2.1 BACKGROUND AND HISTORY

To accurately characterize the current condition, O&M practices and spending, as well as current Plant needs, and to forecast future Plant needs, it was necessary for the Black & Veatch team to understand the history of the Plant in terms of the operations, availability, maintenance practices, modifications, and costs experienced to date. To develop this necessary background, LG&E-KU provided the Black & Veatch team with Plant documentation and reports for the major Plant components. This list of information and reports included the following:

- Forced outage rates
- Availability history
- Maintenance records
- Outage reports
- Original equipment manufacturer (OEM) inspections and findings
- Capital expenditures (historical and projected)
- O&M expenses (historical and projected)
- Other relevant documentation

2.2 SITE MEETING AND PLANT WALKDOWN

Black & Veatch conducted a site meeting with the Plant staff on October 25, 2012. This meeting allowed for a discussion of the Plant's condition, operations, maintenance, and plans. The meeting allowed the Black & Veatch staff to explain the purpose and needs for the visit. This meeting was also an opportune time to allow Plant staff to explain any specific requirements of the facility, especially with respect to personnel safety. The site visit included a walkdown of the Plant in order to perform a visual assessment of the condition of the major Plant equipment that is the subject of this study. At the time of the site visit, Brown Unit 1 was out of service for scheduled maintenance and Brown Unit 2 was in operation.

2.3 ASSESSMENT

Black & Veatch reviewed available Plant documentation to assess the historical O&M practices, O&M expenditures, and recent maintenance records of Plant components to evaluate the Plant's condition and historical levels of spending in comparison to other similar type plants. Black & Veatch personnel visually inspected the equipment and systems during the Plant walkdown to evaluate any potential visual deficiencies or indications of potential future maintenance issues. Historical plant performance records were also reviewed and compared to other similar type plants to evaluate the Plant's overall performance. Some of the reasons that may lead to a decision to retire a generating unit include: repair of catastrophic failures, low economic performance, new more efficient and lower cost units coming online, required major capital expenditures for future operation, expiration of permits, and poor reliability. These factors can often lead to an economic decision to retire a unit. Based on its evaluation of this collection of information and site visit observations, Black & Veatch made an engineering judgment regarding the Plant's current condition, historical O&M practices, and remaining useful life.

During the assessment process, the Black & Veatch team evaluated the Plant by considering its major components. Focusing on these components aided in understanding the costs to maintain/replace equipment and the impact on availability. The major components of the Plant that were evaluated in this RUL assessment include the following:

- Steam turbines and generators
- Boilers
- High energy piping
- Boiler feed pumps and feedwater heaters
- Condensate pumps
- Circulating water pumps
- Cooling tower
- Condenser
- Air quality control
- Power distribution and controls
- Generator step-up (GSU) transformers

Black & Veatch's review of these components was intended to assess the condition of the Plant based on the current conditions, in conjunction with historical maintenance and condition assessments, in comparison to Black & Veatch's experience and industry references. The goal of this phase of the process was to characterize the capability of the major equipment over the long term.

3 Plant Operating History and Condition

3.1 PLANT OVERVIEW

The E.W. Brown Station, as illustrated on Figure 3-1, is located on Herrington Lake near Harrodsburg (Mercer County), Kentucky, between Shakertown and Burgin, off of Hwy 33. The station includes three hydroelectric, seven simple cycle natural gas, and three coal fired electric generating units. As noted previously, the subject of this RUL assessment is Brown Units 1 and 2. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems, and thus these units serve an important role in system reliability.

Brown Unit 1 is a 115 MW (nominal) sub-critical pulverized coal unit that began commercial operation May 1, 1957, and includes a Babcock & Wilcox boiler and a Westinghouse steam turbine. Brown Unit 2 is a 180 MW (nominal) sub-critical pulverized coal unit that began commercial operation June 1, 1963, and includes a Combustion Engineering boiler and a Westinghouse steam turbine. Brown Units 1 and 2 are each equipped with low NO_x burners, electrostatic precipitators (ESP), a common flue gas desulfurization (FGD) system, and continuous emissions monitoring systems (CEMS). Table 3-1 provides a summary of the major plant equipment for Brown Units 1 and 2.

The major plant equipment for Brown Units 1 and 2 are commonly found in power plant applications and are well suited for their intended service. The equipment manufacturers are proven, with installations throughout the power industry. These components would be expected to have long service lives if properly operated and maintained, as evidenced by the current reliable operation of the units.

Table 3-1
Brown Units 1 and 2 Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 1	1	Babcock & Wilcox balanced draft Carolina type radiant boiler with reheater originally designed to fire low sulfur Kentucky bituminous coal, rated for 750,000 lb/h of steam at 1,500 psig and 1,005° F[1]
	Unit 2	1	Combustion Engineering natural circulation steam generator boiler with reheater originally designed to fire low sulfur Kentucky bituminous coal, rated for 1,100,000 lb/h of steam at 1,870 psig and 1,005° F[1]
Steam Turbine	Unit 1	1	Westinghouse reheat tandem compound, double-flow turbine, rated for 1,450 psig and 1,000° F steam, and hydrogen-cooled generator rated for 110 MW gross average
	Unit 2	1	Westinghouse reheat tandem compound, double-flow turbine, rated for 1,800 psig and 1000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 179 MW gross average
Draft System	Unit 1	2	Westinghouse FD fans with variable speed hydraulic couplings (50 percent nom.)
		2	Ljungstrom rotating, regenerative-type, vertical shaft, horizontally mounted air preheaters with one external recirculation air fan (50 percent nom.)
		1	TLT-Babcock centrifugal fan utilizing variable inlet vanes for flow control. TECO Westinghouse motor rated at 5,145 HP

Table 3-1 (Continued)
Brown Units 1 and 2 Major Equipment

Description	Unit	Quantity	Characteristics
Draft System	Unit 2	2	Sturtevant Westinghouse FD fans with variable speed hydraulic couplings and 1,250 hp electric motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters and Buffalo Forge preheating coils with coil pumps (50 percent nom.)
		2	R.J. Perkins Co. inlet vane controlled ID fans with 2,500 hp Westinghouse two-speed motor drives (50 percent nom.)
Control System	Unit 1	1	Foxboro IA
	Unit 2	1	Foxboro IA
Circulating Water System	Unit 1	2	Circulating water pumps (60 percent nom.)
		1	Mechanical draft cooling tower
	Unit 2	2	Circulating water pumps (50-percent nom.)
		1	Mechanical draft cooling tower
Generator	Unit 1	1	Westinghouse Frame 2-092X150, rated 114 MW, 13.8 kV, H_2 cooled
	Unit 2	1	Westinghouse, SO 1-S-65-P-992, rated 180 MW, 18 kV, H_2 cooled

Table 3-1 (Continued)
Brown Units 1 and 2 Major Equipment

Description	Unit	Quantity	Characteristics
Condenser	Unit 1	1	Two-pass vacuum condenser
	Unit 2	1	Two-pass vacuum condenser
Condensate and Feedwater Systems	Unit 1	2	Westinghouse vertical, centrifugal, multi-stage axial condensate pumps (100 percent nom.)
		3	Ingersoll-Rand centrifugal, barrel, 10-stage boiler feed pumps with American Blower variable speed fluid drives and General Electric 1,250 hp motor drivers (60 percent nom.)
	Unit 2	2	Allis-Chalmers vertical, centrifugal, multi-stage axial condensate pumps (50 percent nom.)
		2	Ingersoll-Rand centrifugal, barrel, 10-stage boiler feed pumps with American Standard variable speed fluid drives and General Electric 2,250 hp motor drivers (60 percent nom.)
Flue Gas Treatment	Unit 1	1	Cold-side dry ESP for PM removal
			Low-NO_x burner combustion controls
	Unit 2	1	Cold-side dry ESP for PM removal
			Low-NO_x burner combustion controls
	Common		Limestone-based FGD system designed for 98.5% SO_2 removal

1. Brown Units 1 and 2 were designed to burn low sulfur, lower ash, higher Btu Kentucky coal, and historically the Units have been operated this way. In transitioning Units 1 and 2 to burning higher sulfur, lower quality coal, the Units may see an increase in slagging, accelerated wear and tear, and somewhat higher maintenance. However, Cane Run Unit 6 was also designed to fire low sulfur Kentucky coal similar to Brown Units 1 and 2, but never operated with this coal. Therefore, Cane Run 6's past success operating with an alternate fuel suggests that Brown Units 1 and 2 may also experience a successful fuel switch in the future. Black & Veatch notes that successful fuel switching in coal fired power plants is often achieved.

3.2 PERFORMANCE

3.2.1 Operating Statistics

Table 3-2 presents recent historical net generation, net heat rate, capacity factor, equivalent availability factor, and equivalent forced outage rate for Brown Units 1 and 2 from 2006 through 2011.

Table 3-2
Historical Performance Data for Brown Units 1 and 2

	2006	2007	2008	2009	2010	2011	Average
Unit 1							
Net Generation (MWh)	480,534	493,483	513,921	217,008	411,311	317,251	405,585
Net Heat Rate (BTU/kWh)	11,254	11,124	11,006	11,682	11,064	12,021	11,429
Capacity Factor (%)	54.0	55.5	56.4	24.4	46.3	35.5	45.4
Equivalent Availability Factor (%)	89.8	77.6	74.8	84.1	85.3	90.9	83.8
Equivalent Forced Outage Rate (%)	3.5	5.4	16.4	13.5	2.6	4.5	7.7
Unit 2							
Net Generation (MWh)	956,008	1,013,933	1,074,881	547,458	763,280	616,832	828,732
Net Heat Rate (BTU/kWh)	10,252	10,352	10,261	10,414	10,293	10,825	10,427
Capacity Factor (%)	65.0	68.9	34.9	37.2	51.9	41.9	50.0
Equivalent Availability Factor (%)	89.4	91.9	94.2	78.1	84.9	82.5	86.8
Equivalent Forced Outage Rate (%)	3.5	2.0	3.5	5.5	7.9	6.7	4.9

Figures 3-1 and 3-2 illustrate the historical equivalent availability factor (EAF) and equivalent forced outage rate (EFOR) for Brown Units 1 and 2, respectively, and compare these metrics to industry average data. Industry average data comes from the Generator Availability Data System (GADS) provided by the North American Electric Reliability Council and reflects similarly sized pulverized coal units in the Southeast Reliability Council (SERC) and Reliability First Council (RFC) for the years 2006 through 2010 (data for 2011 was not available at the time this report was prepared)[1]. The industry averages represent units between 100 MW and 250 MW with commercial operation dates between 1950 and 1980.

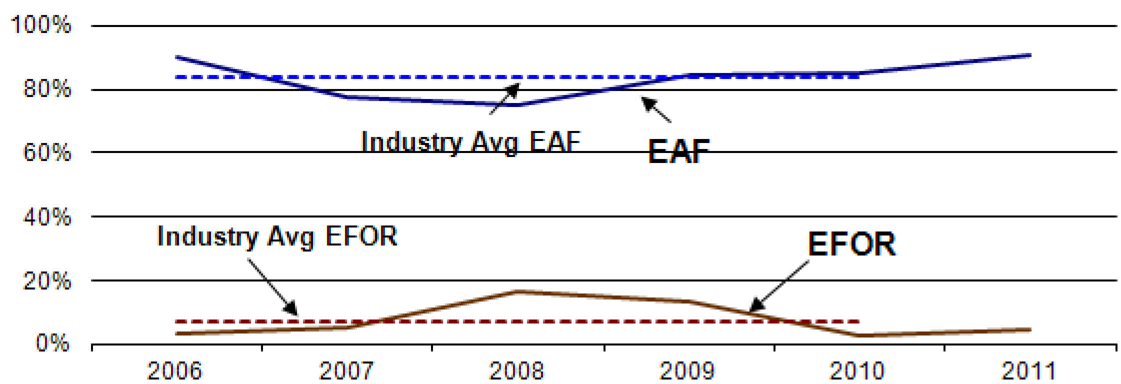

Figure 3-1
Brown Unit 1 Historical EAF and EFOR

[1] Inclusion of units in the SERC decreases the industry average EFOR and increases the industry average EAF against which Brown Units 1 and 2 are compared due to differences in climate and environmental policies between SERC and RFC, which affect unit design and operations. Exclusion of SERC such that comparative statistics are based only on units in RFC increase the industry average EFOR to 9.4 percent and decrease the industry average EAF to 80 percent.

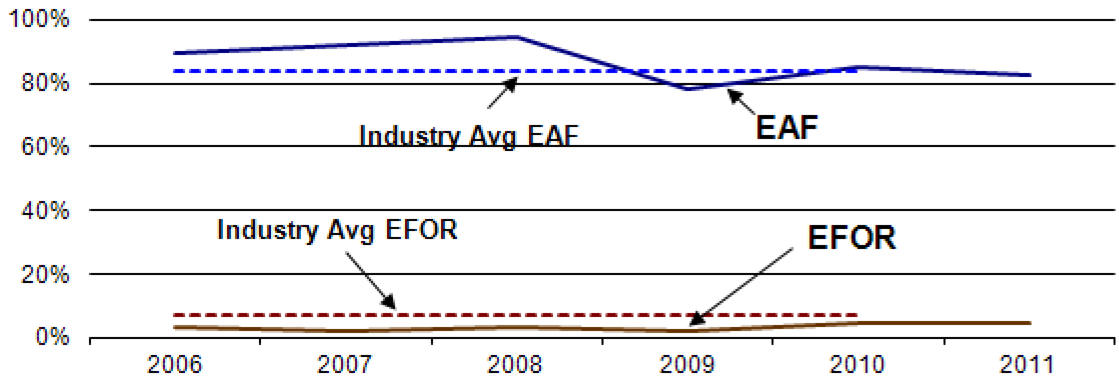

Figure 3-2
Brown Unit 2 Historical EAF and EFOR

Over the 2006 through 2010 period, Brown Unit 1 EAF averaged 82.3 percent, which is slightly below the industry average EAF of 83.8 percent for this time period. However, it should be noted that the unit's EAF has increased every year from 2008 (74.8 percent) through 2011 (90.9 percent). The average EFOR for Brown Unit 1 from 2006 through 2010 is 8.3 percent, which is slightly higher than the industry average of 7.2 percent. However, the average EFOR during this period is adversely impacted by high EFOR in 2008 and 2009; EFOR in subsequent years has averaged 3.6 percent. Issues contributing to EFOR in 2010 and 2011 are discussed towards the end of this subsection. Recent trends in EAF and EFOR indicates that appropriate measures have been taken to address issues that contributed to reduced availability of Brown Unit 1.

Over the 2006 through 2010 period, Brown Unit 2 EAF averaged 87.7 percent, which is above the industry average EAF of 83.8 percent for this time period. The average EFOR for Brown Unit 2 from 2006 through 2010 is 4.5 percent, which is favorable when compared to the industry average of 7.2 percent. It should be noted that the unit's EAF has shown a relative decline while EFOR has shown a relative increase compared to the average in recent years; issues contributing to EFOR in 2010 and 2011 are discussed towards the end of this subsection. Overall, Brown Unit 2 EAF and EFOR indicate that appropriate measures are taken to maintain the availability of the unit.

Figures 3-3 and 3-4 illustrate the historical capacity factors for Brown Units 1 and 2, respectively, and compare these metrics to industry average data. Industry average data comes from GADS and reflects units in the Southeast Reliability Council and Reliability First Council for the years 2006 through 2010 (data for 2011 was not available at the time this report was prepared)[2]. The industry averages represent units between 100 MW and 250 MW with commercial operation dates between 1950 and 1980.

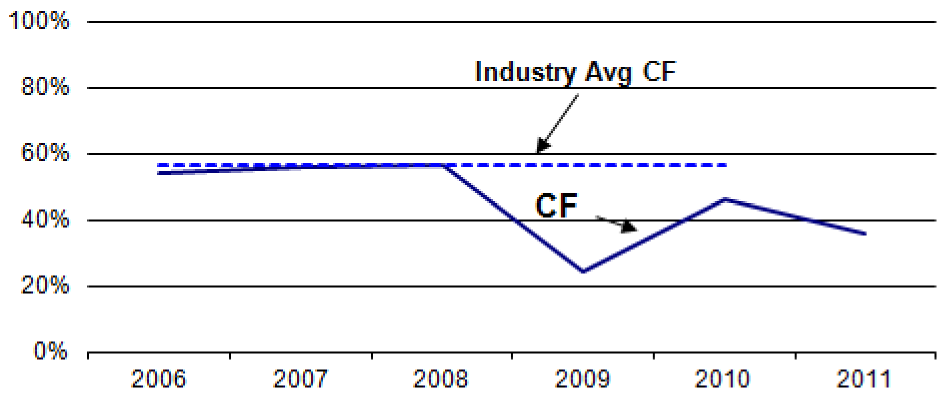

Figure 3-3
Brown Unit 1 Historical Capacity Factor

[2] Inclusion of units in the SERC decreases the industry average EFOR and increases the industry average EAF against which Brown Units 1 and 2 are compared due to differences in climate and environmental policies between SERC and RFC, which affect unit design and operations. Exclusion of SERC such that comparative statistics are based only on units in RFC increase the industry average EFOR to 9.4 percent and decrease the industry average EAF to 80 percent.

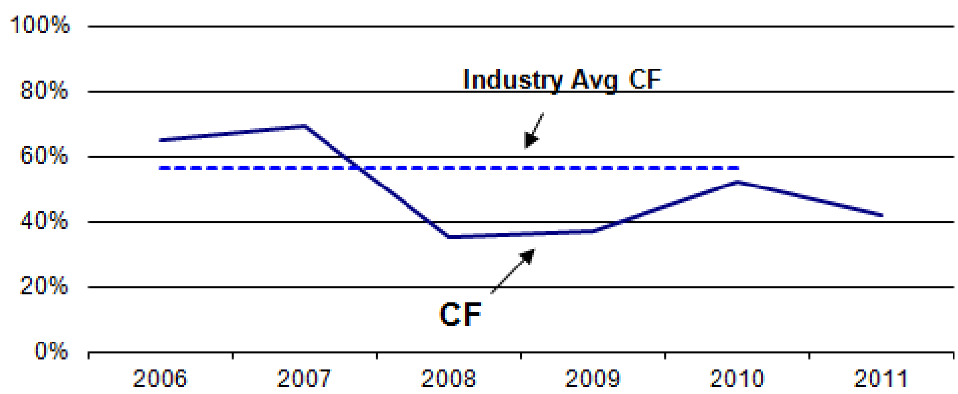

Figure 3-4
Brown Unit 2 Historical Capacity Factor

As shown in Figures 3-3 and 3-4, for the 2006 through 2010 period Brown Units and 2 realized average capacity factors of 47.3 percent and 51.6 percent, respectively. Both Brown Unit 1 and 2 capacity factors were below the industry average of 56.7 percent for this period. While comparison of capacity factors may be informative, such comparisons fail to take into account specifics of the system and markets in which units operate, and as such the comparison of capacity factors should be considered accordingly.

Figure 3-5 illustrates the net generation, by unit, annually for 2006 through 2011 for Brown Units 1 and 2. The net generation dropped significantly for both units in 2009, before rebounding slightly in 2010 and 2011 (although still well below generation during the 2006 through 2008 period). Overall, the decrease in generation shown for 2009 through 2011 as compared to 2008 is consistent with overall the trend of generation from coal units in the 100 MW to 250 MW range in the Southeast Reliability Council and Reliability First Council during this time period, indicating the influence of the electric market on the economics of coal-fired generation in these councils is consistent with generation trends experienced by Brown Units 1 and 2.

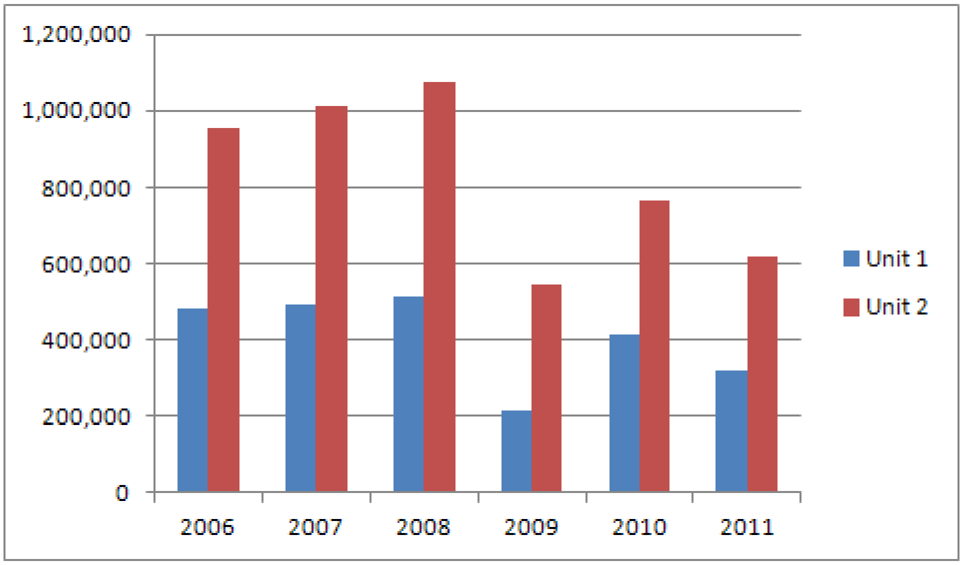

Figure 3-5
Historical Net Generation from 2006 through 2011

Figures 3-6- and 3-7 illustrate monthly net generation for Brown Units 1 and 2, respectively, from January 2010 through September 2012. The following summarizes some of the outage events that occurred during this period:

- Unit 1 experienced decreases in generation in late 2010 due to a planned outage for boiler inspections and repairs and installation of a new turbine control.
- In September 2010, Unit 2 experienced left side throttle valve issues that included actuator damage, improper sealing, and leaks.
- Reserve shutdowns due to market conditions that influence economic dispatch in December 2010 and February 2011 caused decreases in generation for Unit 2.
- Unit 1 experienced a decrease in generation in April 2011 due to miscellaneous inspections and repairs.
- For Unit 2, a boiler inspection in September 2011 and several reserve shutdowns from October 2011 through December 2011 caused a decrease in generation for the latter part of the year.
- From September 2011 through January 2012, Unit 1 experienced decreased generation due to reserve shutdowns.
- In March 2012, Unit 1 experienced a waterwall tube leak that decreased the amount of generation during the incident and for subsequent repair.
- In April 2012, Unit 1 experienced a decrease in generation due to a FGD inspection that was performed prior to the summer season. Black & Veatch understands that this work required completion prior to the summer season, and could not be deferred to the scheduled maintenance outage planned for the fall of 2012.
- The decrease in generation for Unit 2 in April 2012 was due to reserve shutdowns.
- Both Unit 1 and Unit 2 experienced waterwall tube leaks at various times from 2010 through 2012. The leaks occurred in 2010 for Unit 1, and occurred in 2010 and 2012 for Unit 2. These issues caused enough decrease in generation to be reflected in the monthly generation figures.

- Units 1 and 2 experienced deratings in 2010 and 2012 due to opacity restrictions. Unit 1 only experienced a small amount of generation decrease in 2010, but Unit 2 experienced significant durations in 2010 and 2012. The cause code information reviewed by Black & Veatch indicated that many of the opacity deratings were necessary to avoid violating limits on particulate matter emissions.
- Units 1 and 2 experienced several deratings from 2010 through 2012 due to pulverizer mill issues. Issues included shaft failures, trips, leaks, and vibration/noise problems. Although the pulverizer mill issues did not result in significant losses of generation, it should be noted that the lost generation associated with the pulverizer mills increased every year for both units from 2010 through 2012.

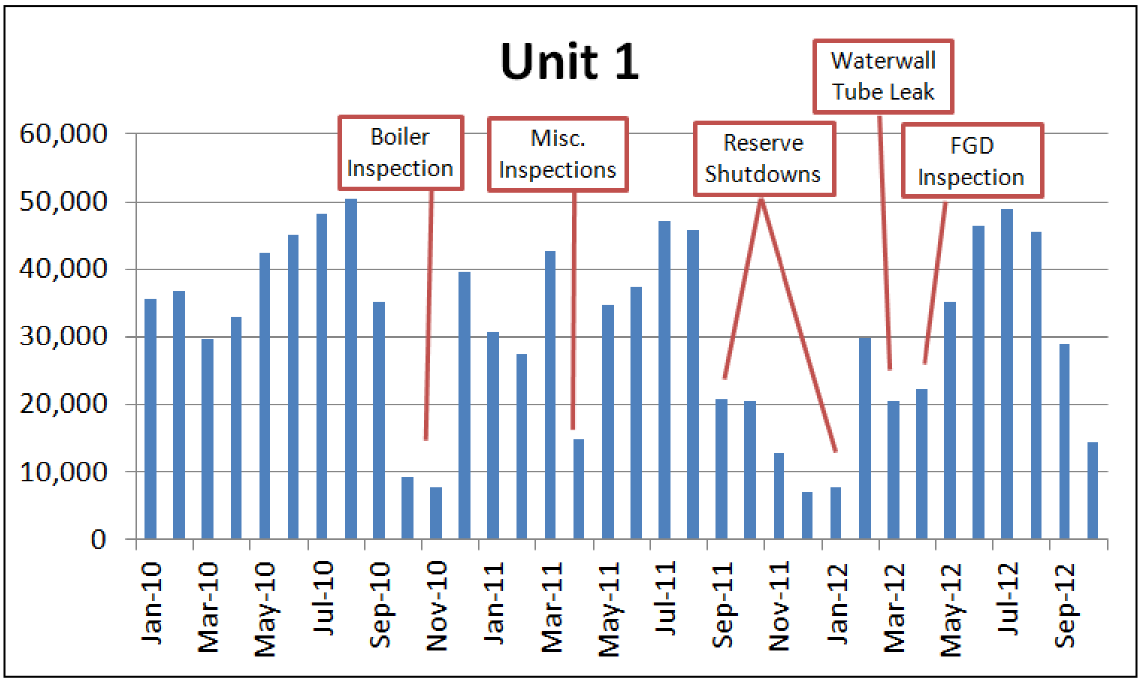

Figure 3-6
Historical Net Generation (MWh) for Unit 1, by Month (2010-2012)

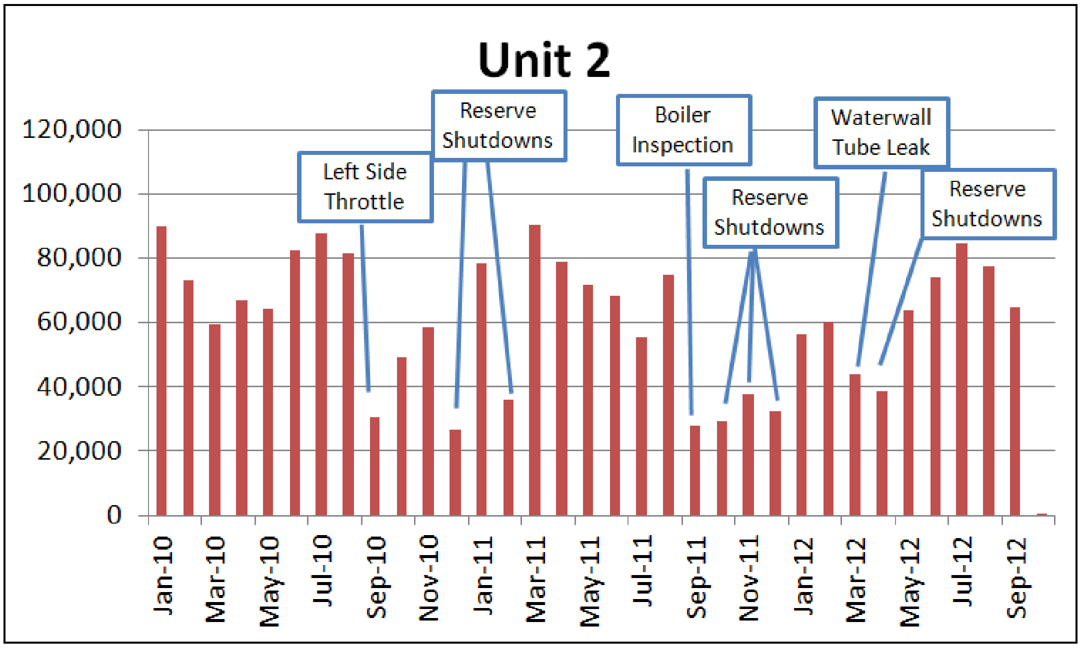

Figure 3-7
Historical Net Generation (MWh) for Unit 2, by Month (2010-2012)

3.2.2 O&M Expenses

An appropriate level of plant O&M spending is required to maintain good operating performance. Recent historical nonfuel O&M expenses for the Brown Units 1 and 2 are shown in Table 3-3. The nonfuel O&M expenses include direct labor, plant spares inventory, plant capital improvements, other capital improvements, fixed O&M costs, variable O&M costs, insurance, outside consulting services, and outside maintenance services. Total annual O&M costs averaged approximately $2.10 million for Brown Unit 1 and $3.68 million for brown Unit 2 over the 2009 through 2011 timeframe. Annual O&M costs for Brown Units 1 and 2 from 2009 through 2011 remain relatively consistent, with the exception of 2009 O&M for Brown Unit 2, which was higher than other years due to scheduled major overhaul activities that included a steam turbine generator major inspection. Analysis of O&M costs on a per MWh basis indicates that O&M costs were relatively high in 2009 (which is expected as a result of the combination of higher costs and reduced generation associated with the major overhaul) before decreasing in 2010, and then increasing in 2011, for both Brown Units 1 and 2 individually and for the Plant as a whole. Brown Units 1 and 2 appear to have O&M costs that are consistent with the O&M costs per MWh of other coal units, recognizing that geographic and design differences between Brown Units 1 and 2 and other coal units influence the comparisons.

Table 3-3
Plant Historical Nonfuel O&M Costs

O&M Costs	2009	2010	2011	Average
Unit 1 (Total $)	$2,122,503	$2,167,537	$2,017,309	$2,102,450
Unit 1 ($ per net MWh)	$9.78	$5.27	$6.36	$6.67
Unit 2 (Total $)	$5,169,924	$2,484,454	$3,372,201	$3,675,526
Unit 2 ($ per net MWh)	$9.44	$3.25	$5.47	$5.72
Total O&M Costs (Total $)	$7,292,427	$4,651,991	$5,389,510	$5,777,976
Total O&M Costs ($ per net MWh)	$9.54	$3.96	$5.77	$6.03

3.2.3 Capital Expenditures

Plant capital expenditures are investments made in the plant to improve performance and safety, meet new regulations, extend plant life, or accomplish other plant improvements. In general, plant owners will often defer capital expenditures for plants that are nearing the end of their useful life so that an owner can avoid having a partially stranded investment. As such, a plant owner that continues to invest in a plant is likely expecting to extend the useful life. Additional capital expenditures may be necessary in order to operate the units in compliance with established and potential future environmental regulations.

Black & Veatch reviewed information provided on recent historical (2009 through 2011) capital expenditures for Brown Units 1 and 2 (as well as future capital plans as discussed further in section 4). The capital expenditures for Brown Units 1 and 2 during this timeframe should contribute to continued reliable plant operations. Historical capital expenditures for Brown Units 1 and 2 are illustrated on Figure 3-8. Notable recent capital expenditures include the following:

- Unit 2 reheat inlet and outlet header replacement (2009)
- Unit 2 precipitator platen replacements (2009 and 2010)
- Unit 2 controls replacement (2009)
- Unit 1 turbine control replacement (2010)
- Unit 2 turbine blade replacement (2011)

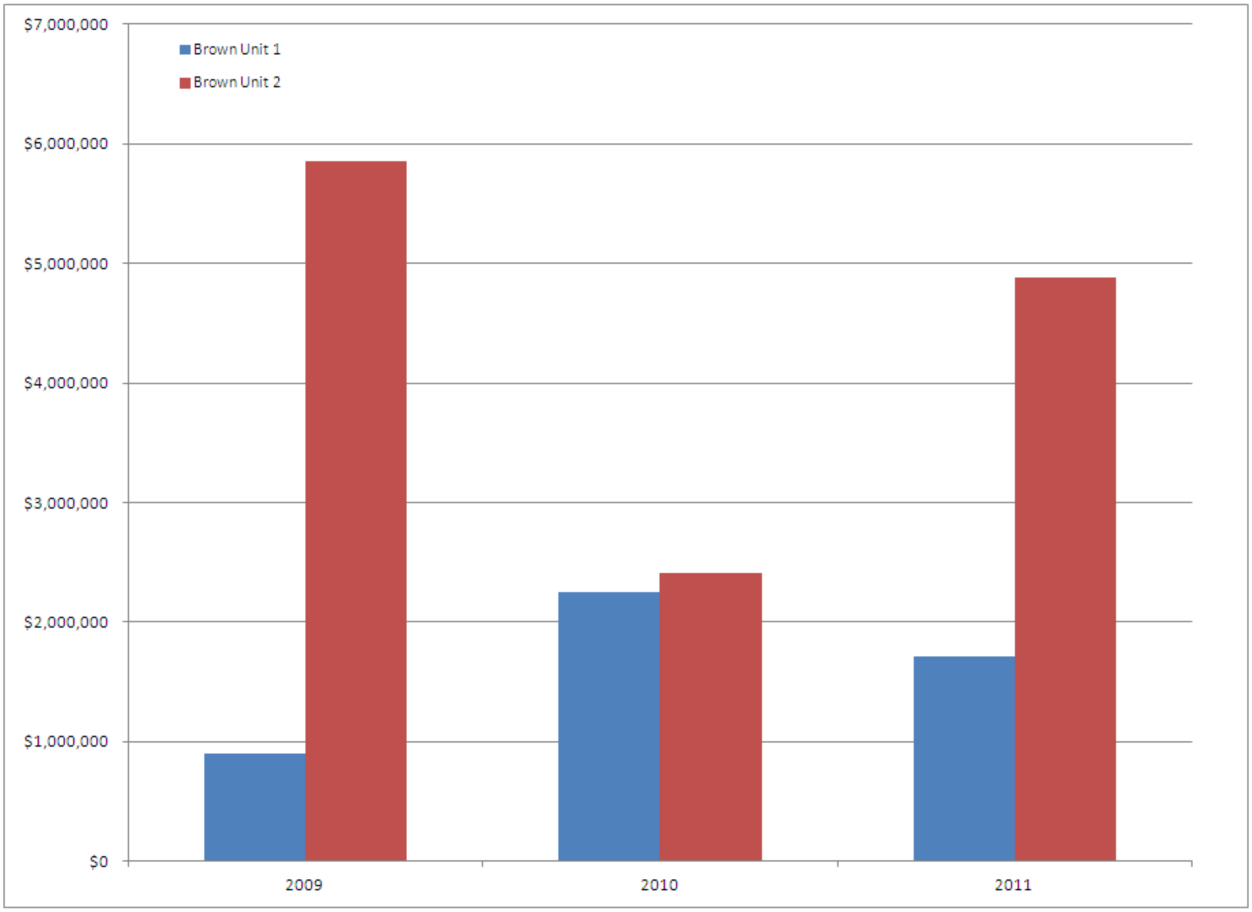

Figure 3-8
Recent Historical Capital Expenditures

3.3 CURRENT CONDITION

Black & Veatch professionals visited the Plant on October 25, 2012, to perform a visual inspection of the Plant condition and interview Plant personnel. In addition, Black & Veatch reviewed recent inspection reports and other documents that discussed Plant equipment condition and availability, which demonstrate the Plant's commitment to making the necessary repairs and replacements and conducting maintenance activities to support continued reliable operation. At the time of the site visit, Brown Unit 1 was out of service for scheduled maintenance and Brown Unit 2 was in operation. The Plant appeared to be in good condition, and the mechanical equipment and structures visually observed during the site tour appeared to be in good condition with no signs of significant leakage of oil, water, or steam; corrosion damage; or other distress.

3.3.1 Steam Turbines and Generators

Plant personnel indicated both Unit 1 and Unit 2 steam turbines operate reliably, with no major issues noted. The Brown Unit 1 and 2 steam turbines underwent major overhauls during their scheduled outages in Fall 2007 and Spring 2009, respectively. The next major inspection is scheduled for Spring 2014 for Unit 1 and Spring 2017 for Unit 2. The Fall 2007 and Spring 2009 major overhauls addressed major items such as rotor bores, turbine shells, seals, gears, turbine bearings, valves, etc.

During the 2007 Unit 1 major overhaul, repairs were made to intermediate pressure (IP) and low pressure (LP) turbine blades and the generator rotor bore was enlarged by bottle boring. Recommendations were made for future inspection activities as well as repairs, including rewinding the generator rotor which is scheduled to occur during 2013/2014.

During the 2009 Unit 2 major overhaul, repairs were made to LP turbine blades and the high pressure (HP) outer and inner turbine shells. Recommendations for more frequent valve inspections and adjustments to the turbine-generator coupling were noted.

3.3.2 Boiler

The Brown Units 1 and 2 boilers are in good general condition, and Plant staff has indicated they are satisfied with the performance of both boilers and concerns about increased slagging associated with burning Illinois Basin coal have not materialized. Plant personnel are working to address air in-leakage issues on both boilers and are confident the issues will be resolved and leakage will be reduced; the Plant has indicated the causes for the leakage for the Unit 2 boiler have been identified and are being addressed, while Unit 1 has several small leaks to address. Recent original equipment manufacturer (OEM) inspection reports indicate limited areas of concern, and Plant personnel are evaluating solutions to improve performance and reliability based on those reports.

3.3.3 High Energy Piping

Non-destructive examinations of high energy piping (HEP) welds are performed for Units 1 and 2 on a periodic basis, with the last inspections occurring in 2007 for Unit 1 and in 2009 for Unit 2. In the event the HEP weld inspections reveal damage that needs to be addressed, necessary repairs are made during the inspection or identified for monitoring or replacement. . The inspections include recommendations made to the Plant regarding return to service and future inspection intervals.

3.3.4 Boiler Feed Pumps

Brown Unit 1 has three 60 percent capacity boiler feed pumps, and Brown 2 has two 60 percent capacity boiler feed pumps. Plant personnel indicated the boiler feed pumps are operating satisfactorily, noting that there have been no performance issues with the pumps and they are typically rebuilt on a 7 to 8 year cycle, which is considered an acceptable cycle. One of the Unit 1 boiler feed pumps was rebuilt in 2011, and the other two are scheduled for rebuild in 2014 and 2016. Unit 2 boiler feed pumps were rebuilt in 2009. The boiler feed pumps were noted to be in good condition during the site visit.

3.3.4.1 Feedwater Heaters

Feedwater heaters have been inspected and have either been replaced in 2010 and 2011 or budgeted for replacement in the MTP. Feedwater heaters typically have long service lives with good operations and maintenance practices, and are not expected to limit Plant life.

3.3.5 Condensate Pumps

Brown Units 1 and 2 each include two (2) 50 percent capacity condensate pumps. Plant personnel indicated the condensate pumps are operating satisfactorily, noting that there have been no performance issues with the pumps. The condensate pumps were noted to be in good condition during the site visit.

3.3.6 Circulating Water Pumps

Brown Units 1 and 2 each include two (2) 50 percent capacity circulating water pumps. Plant personnel indicated the circulating water pumps are operating satisfactorily, noting that there have been no performance issues with the pumps. The circulating water pumps were noted to be in good condition during the site visit.

3.3.7 Cooling Tower

Brown Units 1 and 2 each include a mechanical draft, closed-loop, six (6) cell cooling tower. The original cooling towers were wood-framed units. The Unit 1 cooling tower is in the process of being rebuilt to fiber reinforced plastic (FRP) construction, with completion scheduled in 2014. The Unit 2 cooling tower is scheduled to be rebuilt to FRP construction in 2017. During the site visit, progress was observed on the FRP rebuild of the Unit 1 cooling tower.

3.3.8 Condenser

Brown Units 1 and 2 each include a two-pass vacuum condenser. Plant personnel indicated the condensers are operating satisfactorily, noting that there have been no performance issues with the condensers. The condensers were noted to be in good condition during the site visit.

3.3.9 Air Quality Control

Brown Units 1 and 2 each include a cold-side dry ESP for removal of particulate matter (PM), low NO_x burners, and share a common (between Brown Units 1, 2, and 3) limestone-based flue gas desulfurization (FGD) system to reduce emissions of sulfur dioxide (SO_2). While the Plant has taken responsible measures to maintain the ability to continue to operate within environmental permit requirements, as future environmental regulations are enacted, additional attention may need to be focused on air quality control.

3.3.10 Power Distribution and Controls

Brown Units 1 and 2 each utilize Foxboro I/A series distributed controls systems (DCS). The Unit 1 DCS was installed in 2007, while the Unit 2 DCS was installed in 2010. The DCS for Units 1 and 2 have operated reliably, and Plant personnel did not indicate any issues or concerns with the DCS for either Unit 1 or 2.

3.3.11 GSU Transformers

The electrical power output of the Brown Unit 1 and 2 generators is stepped up by generator step-up (GSU) transformers to the 138 kV system. The connection from the generators to their associated GSU transformers is by isolated phase bus duct. Normal operating power for auxiliary equipment for each unit is derived from dedicated main auxiliary transformers, which are directly connected to their associated generator buses. The GSU transformers appeared to be in good condition with no visible oil leaks when the site visit was conducted. The Plant staff performs Dissolved Gas Analysis (DGA) and infrared inspections at least once per year, which Black & Veatch considers appropriate.

3.4 CONCLUSION ON OPERATIONS AND CONDITION

In summary, Brown Units 1 and 2 appear to be appropriately operated and maintained, in good condition for units of this vintage, and operating near industry averages with respect to availability and forced outages. Recent operating and maintenance experience does not suggest that there are operational useful life issues pending. In addition, the level of recent capital and planned future expenditures (as discussed in Section 4) should help improve useful life. With proper operation, maintenance, renewals and replacements, Brown Units 1 and 2 would be expected to be able to continue to operate at or above recent historical performance.

4 Industry Useful Life Experience

Technical and economic factors are the primary issues that affect the useful life of a power plant. In general, the power industry has demonstrated the ability to extend the useful life of power generation facilities when the economics are favorable. Extending the useful life requires a commitment by the plant owner to continue capital investment in an aging plant.

4.1 FACTORS AFFECTING END OF ECONOMIC LIFE

The trend in the electric power generation industry for the past 20 years has been to continue to invest in modifications to existing units in order to defer retirement. As a result, there are many units operating today that have achieved long lives exceeding 60 years of operation. Given recent trends in the energy industry, retirement of coal units may be driven by entity-specific considerations other than age and condition, such as economics and environmental aspects. This section presents the general technical and economic factors that affect the end of the economic life of the major equipment.

4.1.1 Technical

Utility experience suggests that there are no technical issues, aside from catastrophic failure (the risk of which has been mitigated through the operations and maintenance procedures at the Plant), to preclude a unit from operating longer than its design life. Over time, the performance of plant equipment will degrade; however, good maintenance practices and selective capital investment will effectively mitigate equipment performance degradation. Thus far, the maintenance practices and capital investments for Brown Units 1 and 2 have proven to be prudent insofar as the units continue to operate reliably despite their current ages.

4.1.2 Economic Operation

The economics of a generating plant is generally the most important factor in the retirement decision. Given current market conditions (in particular, the relatively low price for natural gas that is influencing relative economics towards dispatching gas-fired generation ahead of coal-fired resources) and recent and pending environmental regulations, decisions related to economic retirement of smaller, relatively less efficient coal-fired units have become more prevalent.

4.2 INDUSTRY UNIT LIFE DATA

4.2.1 Analysis of Operating and Retired Coal Units

Figures 4-1 and 4-2 illustrate how Brown Units 1 and 2 compare in age to operating and retired coal plants across the United States. Figure 4-1 illustrates the number of operating or standby units, by age, in five year increments (the total number of units represented is 1,547 units). Unit 1 falls into the category of units that are 55 to 60 years old, which represents approximately 12 percent of all the units in the population. Unit 2 falls in the 45 to 50 year old range, which represents approximately 8 percent of the population.

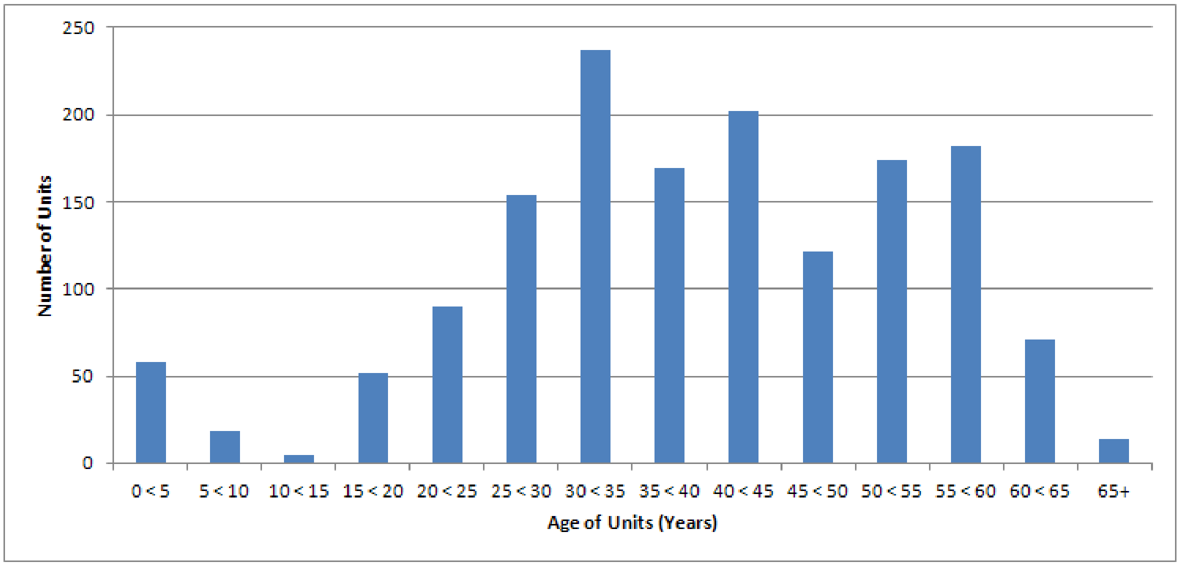

Figure 4-1
Age Distribution of the Operating and Standby Coal Units

Figure 4-2 illustrates the quantity of retired units, regardless of reason, by age at the time of retirement, in five year increments. The units include those with an operating or standby status and the total population size is 434 units. Unit 1 falls into the category of units that are 55 to 60 years old, which represents approximately 10 percent of all the units in the population. Unit 2 falls in the 45 to 50 year old range, which represents approximately 13 percent of the population.

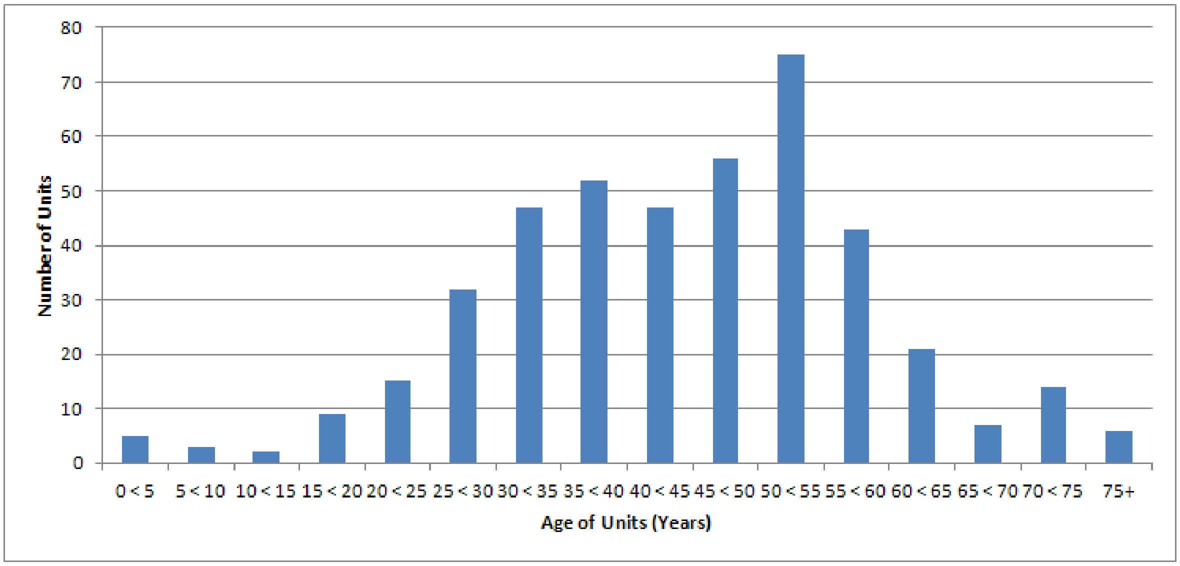

Figure 4-2
Age Distribution by Unit of the Retired Coal Units

As shown in the figures above, Brown Units 1 and 2 are in an expected age range for similar units. In addition, neither unit is at the far extreme of plant life for similar sized plants. Additionally the figures indicate that useful lives beyond 60 to 70 years are achievable for similar units.

4.3 PLANNED CAPITAL EXPENDITURES

To maintain a long service life for any power plant facility, it is necessary to continue making capital investments in the plant. In assessing the useful life of a particular plant, a near-term forecast of planned capital expenditures is useful in evaluating an owner's overall commitment to maintaining a plant over the long term. Plants that are viewed as having a limited remaining useful life will often have minimal capital investments planned in order to avoid having stranded investments upon plant retirement.

4.3.1 Plant Capital Expenditure Forecast

Black & Veatch reviewed information provided on planned (2013 through 2021) capital expenditures for Brown Units 1 and 2, which are illustrated on Figure 4-3. The planned capital expenditures appear to be reasonable based on the age of Brown Units 1 and 2. The level of planned capital expenditures is also indicative of plants that are intended to remain in operation as opposed to plants that are expected to retire in the next few years. Taken in combination with the previously discussed recent historical capital expenditures for Brown Units 1 and 2, the forecast capital expenditures are expected to contribute to continued reliable plant operations. Notable planned capital expenditures include the following:

- Unit 2 CO grid improvements (planned in 2013)
- Unit 1 economizer and header replacements (planned in 2013 and 2014)

- Unit 1 primary superheater top intermediate bank replacements (planned in 2013 and 2014)
- Unit 1 generator rotor rewind (planned in 2013 and 2014)
- Unit 1 cooling tower rebuild (planned in 2013 and 2014)
- Unit 1 CO grid improvements (planned in 2014)
- Unit 2 heater replacement (planned in 2016 and 2017)
- Unit 2 generator rewind (planned in 2016 and 2017)
- Unit 2 cooling tower rebuild (planned in 2016 and 2017)
- Unit 1 baghouse bags and cages (planned in 2017 and 2021)
- Unit 2 baghouse bags and cages (planned in 2017 and 2021)
- Unit 2 turbine recontrol (planned in 2021)

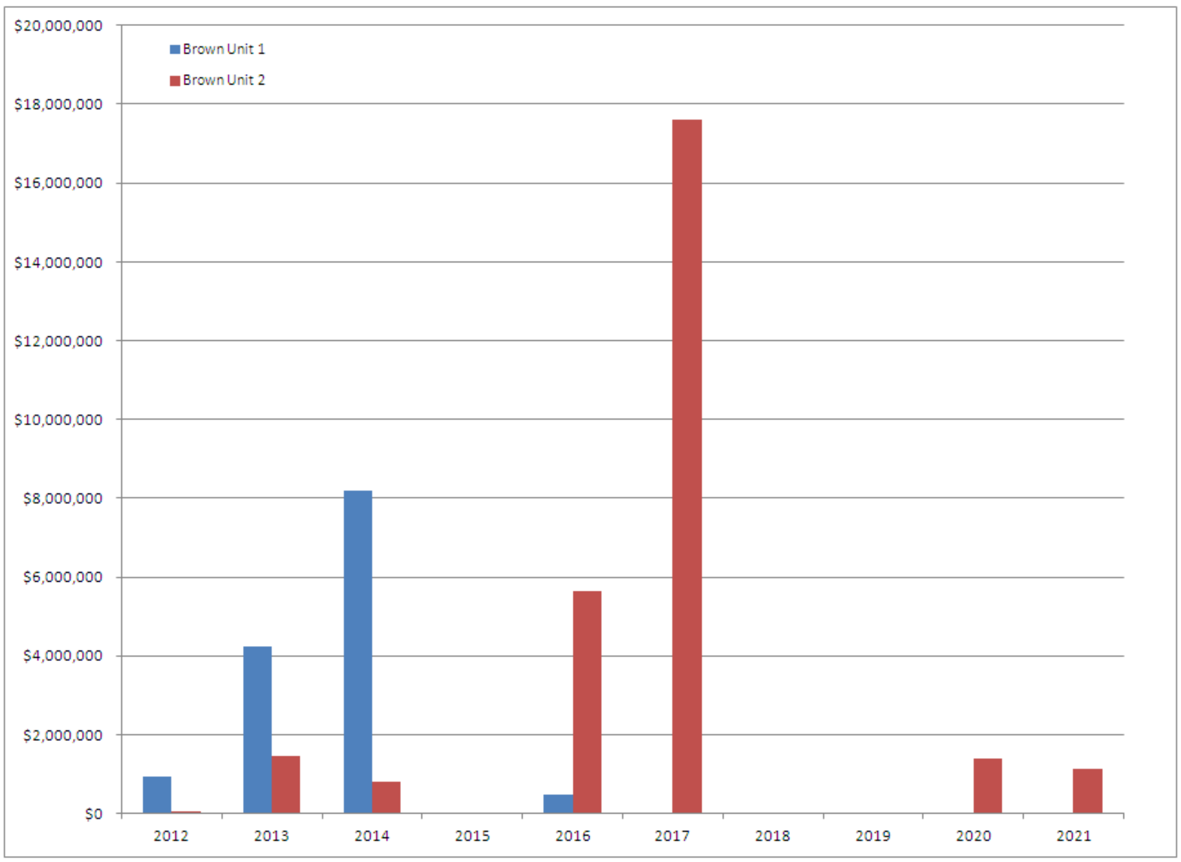

Figure 4-3
Planned Future Capital Expenditures

5 Conclusions

In determining a remaining useful life, Black & Veatch evaluates industry experience with similar type units, the current condition of the plant, historical and future spending for capital expenditures and O&M expenses, and operating procedures and practices. These factors help establish past demonstrated experience in the industry, and plant condition and trends.

Black & Veatch personnel reviewed available plant operational, maintenance, and expense data related to the past operation of the Plant. Black & Veatch personnel inspected the major plant equipment during the site visit that occurred on October 25, 2012. Black & Veatch personnel also evaluated plant age-related data for similar type power plants within the United States to determine real-world historical data on plant useful lives. These investigations and analyses were used to form an opinion of the remaining useful life of the Plant.

In forming this useful life opinion, it has been assumed that the Plant would be appropriately operated and maintained, that replacements and renewals would be made in a timely manner, that the plant would not be operated beyond its technical limitations and any limitations recommended by the OEMs, that permits and approvals would be obtained in due course, that water and fuel would continue to be available on economic terms throughout the Plant's useful life, and that capital investments would be made as required. Black & Veatch's conclusions are summarized below:

- The Plant design and level of equipment redundancy is appropriate for the expected service. No deficiencies or limitations were identified.
- In general, the Plant appears to have adequately defined staff responsibilities, safety programs, work order processes, and predictive maintenance/preventive maintenance procedures. The Plant has been well maintained, and historical O&M expenditures appear to be reasonable based on actual operation. Black & Veatch would expect future levels of O&M spending to be comparable with adjustments made for actual scheduled overhaul activities, changes in levels of dispatch, and inflation.
- The Plant is appropriately staffed for expected future operating requirements, and plant staff is considered qualified to fulfill their O&M obligations.
- The Plant's AQC equipment allows operations within the requirements of environmental operating permits; however, as future environmental regulations may be enacted, LG&E/KU should monitor the need for environmental retrofits to allow Brown Units 1 and 2 to continue to comply with environmental regulations.
- While it is difficult to predict the exact nature of future renewals and replacements, Black & Veatch has not identified any expected renewals or replacements that would result in the early retirement of the Plant.
- An appropriate level of capital expenditures has been forecast for the next few years for continued operation. It is expected that capital expenditures will continue to be evaluated on an annual or more frequent basis, and investments made when required.
- Analysis of industry data (which includes retirements for all reasons) for similar units indicates that coal units such as Brown Units 1 and 2 may be expected to have useful lives ranging as high as 65 to 70 years. Assuming that the Plant continues to be appropriately operated and maintained, with required renewals and replacements made in a timely manner, Black & Veatch

is of the opinion that the Brown Units 1 and 2 may continue to operate in a reliable manner, with nothing indicating that the remaining useful life of either unit is limited in the foreseeable future based on the current condition of the units.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 8

Witness: Charles R. Schram

Q-8. Refer to the IRP, pages 6-11 and 6-13. The Companies note that 137 customers moved from the commercial to the industrial classification. What drives this migration?

A-8. An analysis of customers in the billing system was conducted in early 2011 to validate customer tax classification and the appropriate revenue class. As a result of this review, the revenue class for some customers was updated based on information received from customers. This does not reflect or indicate customers changing rates, but is merely a reclassification of revenue.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 9

Witness: Charles R. Schram

Q-9. Refer to the IRP, page 6-30, which indicates that LG&E and KU use the most recent 20-year average of heating and cooling degree days to represent average weather based on data from the National Oceanic and Atmospheric Administration ("NOAA").

a. Explain why LG&E and KU selected a 20-year average of degree days rather than an average for a different length of time and include in the response when LG&E and KU began using a 20-year average to represent average weather.

b. Explain whether LG&E and KU have ever relied on a source other than NOAA for weather data and, if so, identify the source.

A-9.

a. A 20-year period has been used to represent average/normal weather since KU and LG&E merged in 1998. The 20-year period is long enough to include a range of weather patterns in the winter and summer periods.

b. The Companies are not aware of sources other than NOAA previously used for weather data. The Companies can confirm that NOAA has been the source for weather data since the Companies' merger in 1998.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 10

Witness: Charles R. Schram

Q-10. Refer to the IRP, page 6-32, *Changes in Methodology,* which states,

> In the 2011 IRP, the company used class-specific load profiles to develop its hourly demand forecasts in an effort to better reflect demand-side management programs that impact the load profile of specific classes. In the 2014 IRP, the company further improved this process by using historical hourly shapes by company, month, and day of week with different weather ranges to better reflect load shapes for different temperature ranges.

Explain whether the Companies used class-specific load profiles, including the industrial sector.

A-10. Hourly data for each company from the energy management system was used to develop the demand forecasts. This data is the most accurate and complete available to determine the load impact of variables such as weather and day of week. Class-specific load profiles, including the industrial class profiles, were then evaluated for consistency with the output of this process. In this way, the impact of any potential sampling errors or limitations of the class-specific load research data are minimized.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 11

Witness: Charles R. Schram

Q-11. Refer to the IRP, pages 6-32 and 6-33, which identify four changes in the methodology incorporated into the 2014 IRP forecasts. Confirm that these are the only changes from the methodology used in the 2011 IRP.

A-11. The four changes identified on pages 6-32 and 6-33 are the only changes in the forecasting methodology used in the 2014 IRP compared to the 2011 IRP.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 12

Witness: John N. Voyles

Q-12. Refer to the IRP, page 6-36, where it states, "Prior to this termination, the Companies entered into a new ITO [Independent Transmission Operator] contract with TranServ International, Inc. ("TranServ") for TranServ to perform the role of the ITO, effective September 1, 2012."

a. Describe the Companies' experience with TranServ as its ITO, and identify and explain any issues that have arisen since entering into the new contract.

b. Explain what steps the Companies are taking to procure ITO services once the contract with TranServ expires on August 31, 2015.

A-12.

a. As the ITO, TranServ has been performing transmission studies for the LG&E/KU transmission system since September 1, 2012. These studies have been performed on time and the status of the studies is posted on OASIS by TranServ. The Companies have had good experience with TranServ and are satisfied with their performance under the contract.

b. The contract for TranServ services requires a one year termination notice and if the notice is not given, the contract provisions include an automatic extension of one year. The contract provisions include two such one-year extensions. The Companies expect to continue using TranServ as the ITO under the current contract until August 31, 2017.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 13

Witness: Charles R. Schram

Q-13. Refer to the IRP, page 6-38. It is stated that renewable energy resources are not currently economic in Kentucky. Justify this statement as it contrasts with the Companies 10-megawatt ("MW") solar facility proposed at the Brown station.

A-13. There is no inconsistency between this statement and the Companies' proposal to construct the Brown Solar facility. The statement referenced in this question states that renewable resources "generally are not currently economical in Kentucky." In the 2014 Resource Assessment, the supply-side screening analysis evaluated four renewable technology options over two iterations of 540 cases (see Section 2.4 of the 2014 Resource Assessment beginning at page 25). Given the uncertainty in (a) the availability of investment tax credits ("ITCs") for renewable resources and (b) renewable energy certificate ("REC") prices, the first iteration excluded ITCs and the sale of RECs for renewable resources; the second iteration included ITCs and the sale of RECs. Without ITCs and the sale of RECs, renewable technologies were not among the top four least-cost technology options in any of the 540 cases evaluated (see Table 18 at page 27 of the 2014 Resource Assessment). With the inclusion of ITCs and the sale of RECs, solar photovoltaic, wind, and hydroelectric technologies were among the top four least-cost technology options in only 14, 11, and 1 of the 540 cases evaluated, respectively (see Table 19 at page 27 of the 2014 Resource Assessment). To summarize, solar photovoltaic and wind technologies are most competitive in a carbon-constrained world with high fuel prices, but only if the Companies can take advantage of ITCs and sell RECs.

The analysis supporting the construction of the Brown Solar facility reached a similar conclusion.[2] In that analysis, the Brown Solar facility was most economical in a carbon-constrained world with high fuel prices if the Companies can take advantage of ITCs and sell RECs. The economics of the Brown Solar Facility continue to be based on: (i) the ability to capture the ITC by having the facility completed by December 31, 2016, (ii) the value of RECs that can be sold in other states, (iii) the marginal fuel cost savings of generation that it displaces, (iv) a hedge against an increase in future natural gas prices,

[2] See Case No. 2014-00002, Exhibit DSS-1 to David Sinclair's direct testimony, Section 4.6 beginning at page 43, January 17, 2014.

and (v) the ability to reduce potential future CO_2 compliance costs. In addition, moving forward with Brown Solar facility will afford the Companies an opportunity to gain operational experience with this type of resource should the economics continue to improve and future CO_2 regulations enhance their value to the system.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 14

Witness: Charles R. Schram

Q-14. Refer to the IRP, pages 7-5 and 7-37, which among other things, show each company's annual energy losses for the past five years as a percentage of energy requirements. Other than in 2011, when it was 5.7 percent, LG&E's losses percentage was consistently in a range of 4.0 to 4.5 percent over this period, while, other than in 2011, when it was 4.7 percent, KU's losses percentage was in a range of 5.7 to 6.9 percent annually during this same period. Explain why KU's percentage regularly exceeds LG&E's percentage in this manner.

A-14. Compared to the LG&E system, KU's transmission and distribution system covers a larger geographical footprint to serve a larger number of customers. KU's associated transmission and distribution energy losses are consistent with the more expansive transmission and distribution system.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No.15

Witness: Charles R. Schram

Q-15. Refer to the IRP, page 7-23, the paragraph headed "Primary Municipal." The last part of the final sentence in the paragraph refers to "transmission" municipal customers. Should this reference be to "primary" municipal customers rather than "transmission" municipal customers?

A-15. Yes, the sentence should read, "Sales to primary municipal customers were modeled as a function of weather and the number of households in the counties where the primary municipal customers are located."

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 16

Witness: Charles R. Schram

Q-16. Refer to the IRP, pages 7-32 and 7-33. As stated in the section on Changes in Methodology on pages 6-32 and 6-33, the final paragraph on page 7-32 refers to commercial end-use surveys conducted and used to develop assumptions for small commercial forecasting models. The final paragraph on page 7-33 indicates that LG&E and KU conducted a small commercial end-use survey in early 2011. Explain whether the 2011 survey is the only commercial end-use survey relied upon to develop assumptions for small commercial forecasting models.

A-16. The 2011 survey was the only commercial end-use survey relied upon to develop assumptions for the small commercial forecasting models. Additional inputs and assumptions were provided by Itron from the Energy Information Agency's (EIA) Annual Energy Outlook. These assumptions are specific to census regions to consider regional differences in commercial end-use inputs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 17

Witness: Charles R. Schram

Q-17. Refer to the IRP, page 7-50 of the IRP. Confirm that the Louisville Water Company and Fort Knox are the only special contract customers served by either LG&E or KU.

A-17. The statement to which the question refers was accurate at the time the Companies filed their 2014 IRP. Today, it is still true that the Louisville Water Company and Fort Knox are the only special-contract customers served by LG&E, but KU has since acquired a special-contract customer, American Municipal Power, Inc. ("AMP"), concerning KU's service to AMP's new hydroelectric facility at the Captain Anthony Meldahl Locks and Dam located near Maysville, Kentucky. That contract does not specify non-tariffed individual rates for AMP; rather, it provides for KU to bill AMP for standard tariffed rates for most of its service, and for standard tariffed rates less a few billing components for a portion of its service.

Also, Economic Development Rider ("EDR") customers must meet specific criteria to qualify but are not considered special contract customers.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
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Case No. 2014-00131

Question No. 18

Witness: John N. Voyles

Q-18. Refer to the IRP, page 8-14, where it states, "However, potential efficiency penalties are associated with some of these projects." Identify all known efficiency penalties for such projects, the amount of the efficiency penalty for each project, and how such penalties have been incorporated into the load forecast.

A-18. See the table below. Efficiency penalties for a given unit are modeled as an increase to the unit's auxiliary load and heat rate, not as an adjustment to the load forecast. Of the projects listed below, the Brown 3 selective catalytic reduction ("SCR") unit, the Ghent station's coal combustion residual transport ("CCRT") system, and the Ghent 3 bag house are currently in service. The remaining projects listed are still in the construction or commissioning process.

Unit	Project	Auxiliary load increase (MW)	Heat rate increase (%)
Brown 1	Mercury control + Coal combustion residual transport (CCRT)	0	0
Brown 2	Mercury control + CCRT	0	0
Brown 3	SCR + Bag house + CCRT	5	1.3
Ghent 1	Bag house + CCRT	6	1.3
Ghent 2	Bag house + CCRT	9	1.9
Ghent 3	Bag house + CCRT	6	1.2
Ghent 4	Bag house + CCRT	6	1.2
Mill Creek 1	Bag house + Flue Gas Desulfurization ("FGD")	3	1.0
Mill Creek 2	Bag house + FGD	4	1.3
Mill Creek 3	Bag house + FGD	6	1.5
Mill Creek 4	Bag house + FGD	11	2.3
Trimble County 1	Bag house	4	0.8

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 19

Witness: John N. Voyles

Q-19. Refer to the IRP, page 8-14, regarding transmission, and page 6 of the 2014 IRP Update provided at the September 15, 2014 Informal Conference ("IC") where it states that transmission system considerations were not affected by the change in municipal load. Identify and describe any transmission planning, transmission regulatory matters, or other transmission issues that have arisen since the IC.

A-19. The Companies plan and maintain their transmission system network to supply all their customer loads. The loads from those municipal customers that gave termination notice to the Companies will still be served from some generating source outside of the Companies and delivered to the municipals utilizing the Companies' transmission network. Under the terms of the Companies' OATT, all transmission requests for service, including the municipals, must be filed with the Companies' ITO, TranServ. Upon receipt of the request a study will be performed to determine what modifications to the network, if any, might be needed to maintain the transmission network for the Companies' customers and deliver the energy to meet the municipal loads.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 20

Witness: Charles R. Schram

Q-20. Refer to the IRP, page 8-23, Table 8.(3)(b) 12(d),(f). State whether the Capital Costs for Brown Solar are net of investment tax credits.

A-20 The Capital Costs for Brown Solar are not net of investment tax credits.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 21

Witnesses: Charles R. Schram

Q-21. Refer to the IRP, page 8-36. The Companies state that through proposed DSM programs, customers will reduce demand by an aggregated 500 MW through 2018. Was this projection based on the recent downturn in projected demand, i.e., the 2014 IRP projections?

A-21 The Companies' 500 MW is based on the activities and projected results of the Companies' DSM/EE Plan as outlined in Case No. 2014-00003. The projected downturn in demand does not materially affect the Companies' anticipated demand reductions due to the Companies' DSM/EE programs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 22

Witnesses: Charles R. Schram

Q-22. Refer to the IRP, page 8-37, where it states, "Considering these changes to the Companies' generation portfolio, along with more than 400 MW of demand reduction from DSM programs by 2018 and 131 MW of curtailable load from curtailable service rider customers, the Companies will have a long-term need for capacity beginning in 2025." On page 5-39 and 8-36 of the IRP, the Companies state that 500 MW of demand reduction will be achieved by 2018. Explain the discrepancy in the demand reduction contained in these statements for the amount of DSM/EE to be achieved by 2018.

A-22 The 2018 demand reduction referenced on page 8-37 uses a lower amount of peak DSM compared to the 500 MW from most recent DSM filing referenced on pages 5-39 and 8-36 of the IRP due to:

1) The 500 MW estimate in the recent DSM filing is based on higher temperatures associated with more extreme summer weather, while the Companies' load forecasts are based on temperatures associated with "average" summer weather. Consequently, less net impact from DSM programs is assumed in the Companies' load forecast at the time of the forecasted summer peak.

2) For 2018, the DSM filing presents a year-end reduction of 500 MW, while the load forecast uses a mid-year estimate to correspond to summer peak load conditions. The impact of DSM program participants added subsequent to the summer period is not included.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 23

Witness: Charles R. Schram

Q-23. Refer to the IRP, page 8-38. The Companies state that the cost of deploying solar PV (photovoltaic) power has significantly declined and is expected to flatten. When do the Companies expect this flattening to occur?

A-23 This statement was based on the 2013 LGE-KU Generation Technology Assessment prepared by Burns & McDonnell (see page 1-10). The report did not specify a date when the cost is expected to flatten. Please see attached. Certain information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

Report on the

Generation Technology Assessment

for

Louisville Gas & Electric Company/ Kentucky Utilities Company

November 2013

Burns & McDonnell
SINCE 1898

Generation Technology Assessment

prepared for

Louisville Gas & Electric Company
Kentucky Utilities Company

(LG&E and KU Energy, LLC)

November 2013

**Project No.
74028**

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

REV 2

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1 EXECUTIVE SUMMARY

1.1 Introduction

Louisville Gas & Electric/Kentucky Utilities Energy Company (LG&E/KU or Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various power generation technologies for installation in Kentucky. Information provided by BMcD is intended to support LG&E/KU in integrated resource planning efforts and in the selection of a general fuel conversion technology(ies) for further development.

This assessment is screening-level in nature and includes a comparison of technical features, cost, performance, waste disposal, and emissions of the following technologies at a greenfield site:

NATURAL GAS TECHNOLOGIES

- Simple Cycle Gas Turbine (SCGT)
    - 50 MW Aeroderivative (GE LM6000) SCGT
    - 100 MW Aeroderivative (GE LMS100) SCGT
    - Frame “E-Class” SCGT
    - Frame “F-Class” SCGT
    - 1 MW Microturbine configuration
- Combined Cycle Gas Turbine (CCGT)
    - “F Class” CCGT
    - “Advanced Class” CCGT
    - “Emerging Advanced Class” CCGT
- Spark Ignition Reciprocating Engine
- Fuel Cell

NUCLEAR TECHNOLOGY

- Small Modular Reactor (SMR)

COAL TECHNOLOGIES

- Subcritical Pulverized Coal (PC)
- Subcritical Circulating Fluidized Bed (CFB)
- Supercritical Pulverized Coal (PC)
- Integrated Gasification Combined Cycle (IGCC)

WASTE TO ENERGY TECHNOLOGIES

- Stoker Firing
  - Wood Biomass
  - Municipal Solid Waste (MSW)
  - Refuse Derived Fuel
- Coal / Biomass Co-Firing
  - CFB with 50% biomass / 50% coal
  - PC boiler conversion to 10% biomass / 90% coal
- Internal Combustion
  - Landfill Gas
  - Anaerobic Digestion

RENEWABLE TECHNOLOGIES

- Wind Energy Conversion
- Solar Energy Conversion
- Hydroelectric Energy Conversion

ENERGY STORAGE TECHNOLOGIES

- Pumped Hydroelectric Energy Storage
- Advanced Battery Energy Storage
- Compressed Air Energy Storage (CAES)

1.2 Technology Assessment Summary

The results of the technology assessment are summarized in Table 1.1 through Table 1.6 below. A more detailed summary table is included in Appendix A.

Table 1.1: Executive Summary – Natural Gas Simple Cycle Gas Turbine Technologies

Criteria	1xLM6000 SCGT		1xLMS100 SCGT		1xE-Class S0CGT		1xF-Class SCGT	
Phase		Add-on		Add-on		Add-on		Add-on
Unit Configuration	1 GT	1 GT	1 GT	1 GT	1 GT	1 GT	1 GT	1 GT
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Performance								
Avg Ambient Base Load Net Plant Output, kW	48,700	48,700	105,600	105,600	86,800	86,800	211,200	211,200
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Air Quality Control Equipment								
NO_x Control	Water Injection/SCR		Water Injection/SCR		DLN/SCR		DLN	
CO Control	Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Good Combustion Practice	
SO_2 Control	Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Capital Cost								
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]							
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)								
Total Project Costs, 2013 MM$								
Total Project Costs, 2013$/kW								
O&M Costs								
Fixed O&M Cost, $/kW-Yr	[redacted]							
Levelized Major Maintenance Cost, $/GTG-hr								
Levelized Major Maintenance Cost, $/GTG-Start								
Variable O&M Cost, $/MWh (excl. major maint.)								
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)								
NO_x	0.007	0.007	0.007	0.007	0.007	0.007	0.033	0.033
SO_2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051
CO	0.004	0.004	0.004	0.004	0.004	0.004	0.020	0.020
CO_2	120	120	120	120	120	120	120	120
PM/PM10	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
VOC	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Anticipated Operational Emissions Limits, lbs/MWh								
NO_x	0.07	0.07	0.07	0.07	0.08	0.08	0.33	0.33
SO_2	< 0.049	< 0.049	< 0.045	< 0.045	< 0.059	< 0.059	< 0.051	< 0.051
CO	0.04	0.04	0.04	0.04	0.05	0.05	0.20	0.20
CO_2	1160	1160	1070	1070	1380	1380	1190	1190
PM/PM10	0.10	0.10	0.09	0.09	0.12	0.12	0.10	0.10
VOC	0.03	0.03	0.02	0.02	0.03	0.03	0.03	0.03

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Table 1.2: Executive Summary – Natural Gas Simple Cycle Technologies

Criteria	100 MW Recip Engine		1 MW Microturbine		10 MW Fuel Cell	
Phase		Add-on		Add-on		Add-on
Unit Configuration	6 Engines	1 Engine	5 GT	1 GT	4 Cells	1 Cell
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Performance						
Avg Ambient Base Load Net Plant Output, kW	100,200	16,700	1,000	200	11,200	2,800
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]					
Air Quality Control Equipment						
NOx Control	SCR		Low Nox Combustion		N/A	
CO Control	Oxidation Catalyst		N/A		N/A	
SO2 Control	Oxidation Catalyst		N/A		N/A	
Particulate Control	Good Combustion Practice		N/A		N/A	
Capital Cost						
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]					
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)						
Total Project Costs, 2013 MM$						
Total Project Costs, 2013$/kW						
O&M Costs						
Fixed O&M Cost, $/kW-Yr	[redacted]					
Levelized Major Maintenance Cost, $/GTG-hr						
Levelized Major Maintenance Cost, $/GTG-Start						
Variable O&M Cost, $/MWh (excl. major maint.)						
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)						
NOx	0.018	0.018	0.035	0.035	0.001	0.001
SO2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	0.000	0.000
CO	0.034	0.034	0.096	0.096	0.100	0.100
CO2	120	120	120	120	120	120
PM/PM10	0.01	0.01	0.01	0.01	0.00	0.00
VOC	0.003	0.003	0.009	0.009	0.001	0.001
Anticipated Operational Emissions Limits, lbs/MWh						
NOx	0.160	0.150	0.400	0.400	0.010	0.010
SO2	< 0.043	< 0.043	< 0.058	< 0.058	0	0
CO	0.290	0.280	1.100	1.100	0.800	0.800
CO2	1020	1010	1330	1330	940	940
PM/PM10	0.08	0.08	0.11	0.11	0.00	0.00
VOC	0.02	0.02	0.10	0.10	0.01	0.01

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Table 1.3: Executive Summary – Combined Cycle Technologies

Criteria	F-Class CCGT		Advanced Class CCGT		Emerging Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
Operating Conditions	1050 F/1050 F		1050 F/1050 F		1050 F/1050 F	
Fuel Design	Natural Gas		Natural Gas		Natural Gas	
Air Quality Control Equipment						
NO_x Control	DLN/SCR		DLN/SCR		DLN/SCR	
CO Control	Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst	
SO_2 Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)						
NOX	0.007	0.007	0.007	0.007	0.007	0.007
SO_2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051
CO	0.004	0.004	0.004	0.004	0.004	0.004
CO2	120	120	120	120	120	120
PM/PM10	0.010	0.01	0.01	0.01	0.01	0.01
VOC	0.003	0.003	0.003	0.003	0.003	0.003
Anticipated Operational Emissions Limits, lbs/MWh						
NO_x	0.050	0.050	0.050	0.050	0.050	0.050
SO_2	< 0.034	< 0.034	< 0.033	< 0.034	< 0.032	< 0.032
CO	0.030	0.030	0.030	0.030	0.030	0.030
CO_2	790	800	780	790	750	750
PM/PM10	0.07	0.07	0.07	0.07	0.06	0.06
VOC	0.02	0.02	0.02	0.02	0.02	0.02
Performance						
1x1 Plant Configuration						
Avg Ambient Base Load Net Plant Output, kW	315,100	311,900	397,400	393,600	441,100	437,000
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]					
Avg Ambient Incremental Fired Output, kW	N/A	45,200	N/A	58,000	N/A	65,500
Avg Ambient Incremental Fired Heat Rate, Btu/kWh (HHV)	[redacted]					
2x1 Plant Configuration						
Avg Ambient Base Load Net Plant Output, kW	637,600	628,400	796,100	785,200	883,600	871,900
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]					
Avg Ambient Incremental Fired Output, kW	N/A	90,400	N/A	116,100	N/A	130,900
Avg Ambient Incremental Fired Heat Rate, Btu/kWh (HHV)	[redacted]					
3x1 Plant Configuration						
Avg Ambient Base Load Net Plant Output, kW	960,400	946,400	1,198,800	1,182,300	1,330,400	1,312,700
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]					
Avg Ambient Incremental Fired Output, kW	N/A	135,700	N/A	174,100	N/A	196,300
Avg Ambient Incremental Fired Heat Rate, Btu/kWh (HHV)	[redacted]					
Capital Cost						
1x1 Plant Configuration						
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]					
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)						
Total Project Costs, 2013 MM$						
Total Project Costs, 2013$/kW (Unfired Output)						
Total Project Costs, 2013$/kW (Fired Output)						
2x1 Plant Configuration						
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]					
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)						
Total Project Costs, 2013 MM$						
Total Project Costs, 2013$/kW (Unfired Output)						
Total Project Costs, 2013$/kW (Fired Output)						
3x1 Plant Configuration						
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]					
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)						
Total Project Costs, 2013 MM$						
Total Project Costs, 2013$/kW (Unfired Output)						
Total Project Costs, 2013$/kW (Fired Output)						

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Table 1.3: Executive Summary – Combined Cycle Technologies (Continued)

Criteria	F-Class CCGT		Advanced Class CCGT		Emerging Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
O&M Costs						
1x1 Plant Configuration						
Fixed O&M Cost, $/kW-Yr	[redacted]					
Levelized Major Maintenance Cost, $/GTG-hr						
Levelized Major Maintenance Cost, 2013$/GT-Start						
Variable O&M Cost, $/MWh (excl. major maint.)						
Incr. Duct Fired Variable O&M Cost, $/MWh (excl. major maint.)						
2x1 Plant Configuration						
Fixed O&M Cost, $/kW-Yr	[redacted]					
Levelized Major Maintenance Cost, $/GTG-hr						
Levelized Major Maintenance Cost, 2013$/GT-Start						
Variable O&M Cost, $/MWh (excl. major maint.)						
Incr. Duct Fired Variable O&M Cost, $/MWh (excl. major maint.)						
3x1 Plant Configuration						
Fixed O&M Cost, $/kW-Yr	[redacted]					
Levelized Major Maintenance Cost, $/GTG-hr						
Levelized Major Maintenance Cost, 2013$/GT-Start						
Variable O&M Cost, $/MWh (excl. major maint.)						
Incr. Duct Fired Variable O&M Cost, $/MWh (excl. major maint.)						

Table 1.4: Executive Summary – Energy Storage/Renewable/Nuclear Technologies

Criteria	Pumped Hydro Energy Storage	Adv. Battery Energy Storage	CAES	Wind Energy Conversion	Solar Photovoltaic	Solar Thermal	HydroElectric	Small Modular Nuclear
Nominal Output	200 MW	10 MW	135 MW	50 MW	50 MW	50 MW	50 MW	225 MW
Fuel Design	N/A	N/A	Natural Gas	N/A	N/A	N/A	N/A	N/A
Performance								
Avg Ambient Base Load Net Plant Output, kW	200,000	10,000	135,000	50,000	50,000	50,000	50,000	225,000
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]							
Air Quality Control Equipment								
NO_x Control	N/A	N/A	SCR	N/A	N/A	N/A	N/A	N/A
CO Control	N/A	N/A	Good Combustion Practice	N/A	N/A	N/A	N/A	N/A
SO_2 Control	N/A	N/A	Good Combustion Practice	N/A	N/A	N/A	N/A	N/A
Particulate Control	N/A	N/A	Good Combustion Practice	N/A	N/A	N/A	N/A	N/A
Capital Cost								
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]							
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)								
Total Project Costs, 2013 MM$								
Total Project Costs, 2013$/kW								
O&M Costs								
Fixed O&M Cost, $/kW-Yr	[redacted]							
Levelized Major Maintenance Cost, $/MWh								
Variable O&M Cost, $/MWh (excl. major maint.)								
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)								
NO_x	N/A	N/A	0.004	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	< 0.0051	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	0.002	N/A	N/A	N/A	N/A	N/A
PM/PM10	N/A	N/A	0.01	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	0.003	N/A	N/A	N/A	N/A	N/A
Anticipated Operational Emissions Limits, lbs/MWh								
NO_x	N/A	N/A	0.037	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	< 0.03	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	0.022	N/A	N/A	N/A	N/A	N/A
PM/PM10	N/A	N/A	0.05	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	0.02	N/A	N/A	N/A	N/A	N/A

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Table 1.5: Generation Technology Summary – Waste to Energy

Criteria	MSW Stoker Fired	RDF Stoker Fired	Wood Stoker Fired	Landfill Gas IC Engine	Anaerobic Digester Gas IC Engine	Co-fired Circulating Fluidized Bed (CFB) 50% Coal / 50% Biomass	Existing PC Boiler Conversion to Co-fire 90% Coal / 10% Biomass
Nominal Output	50 MW	50 MW	50 MW	5 MW	5 MW	50 MW	100 MW
Unit Configuration	1 Boiler x 1 ST	1 Boiler x 1 ST	1 Boiler x 1 ST	1 Engine x 0 ST	1 Engine x 0 ST	1 Boiler x 1 ST	1 Boiler x 1 ST
Operating Conditions	950 F/950F	950 F/950F	950 F/950F	N/A	N/A	1050 F/1050 F	1050F/1050F
Fuel Design	100 % Municipal Solid Waste	100% Refuse-Derived Fuel	100% Chipped Wood Biomass	100% Landfill Gas	100% Sewage Bio-gas	50% IL Basin Coal / 50% Chipped Wood Biomass	Up to 10% Wood / Up to 100% Coal
Performance							
Avg Ambient Base Load Net Plant Output, kW	50,000	50,000	50,000	5,000	5,000	50,000	100,000
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]						
Air Quality Control Equipment							
NO_x Control	SNCR	SNCR	SNCR	SCR	SCR	SNCR	SCR
CO Control	Good Combustion Practices			Oxidation Catalyst		Good Combustion Practices	
SO_2 Control	Dry Sorbent Injection			None		Limestone Bed Injection/ Polishing FGD	Wet FGD
Mercury Control	Dry Sorbent Injection			N/A		Dry Sorbent Injection	
Particulate Control	Baghouse			Good Combustion Practice		Baghouse	
Capital Cost							
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]						
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)							
Total Project Costs, 2013 MM$							
Total Project Costs, 2013$/kW							
O&M Costs							
Fixed O&M Cost, $/kW-Yr	[redacted]						
Variable O&M Cost, $/MWh (excl. major maint.)							
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)							
NO_x	0.10	0.10	0.10	0.02	0.02	0.06	0.04
SO_2	0.03	0.03	0.03	0.01	0.01	0.03	0.04
CO	0.15	0.15	0.15	0.05	0.05	0.13	0.15
CO_2	205	205	205	180	180	203	200
Hg (lb/Tbtu)	0.80	0.80	0.80	--	--	0.56	0.33
PM/PM10	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Anticipated Operational Emissions Limits, lbs/MWh							
NO_x	1.50	1.40	1.40	0.20	0.20	0.60	0.30
SO_2	0.40	0.40	0.30	0.10	0.10	0.30	0.30
CO	2.20	2.10	2.00	0.50	0.50	1.30	1.40
CO_2	3030	2910	2790	1910	1800	2150	1840
Hg	1.18E-05	1.14E-05	1.09E-05	--	--	6.00E-06	3.00E-06
PM/PM10	0.50	0.50	0.40	0.30	0.30	0.30	0.30

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Table 1.6: Generation Technology Summary – Coal

Criteria	Subcritical Pulverized Coal		Circulating Fluidized Bed		Supercritical Pulverized Coal 500 MW		Supercritical Pulverized Coal 750 MW		2x1 Integrated Gasification CC	
Carbon Capture Description		w/Carbon Capture		w/Carbon Capture		w/Carbon Capture		w/Carbon Capture		w/Carbon Capture
Unit Configuration	1 Boiler x 1 ST		2 Boiler x 1 ST		1 Boiler x 1 ST		1 Boiler x 1 ST		2 GT x 1 ST	
Operating Conditions	1050 F/1050F		1050 F/1050F		1050 F/1050F		1050 F/1050F		1050 F/1050F	
Fuel Design	Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous	
Performance										
Avg Ambient Base Load Net Plant Output, kW	500,000	425,000	500,000	425,000	500,000	425,000	750,000	637,500	618,000	482,000
Avg Ambient Base Load Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]									
Air Quality Control Equipment										
NO_x Control	SCR		SNCR		SCR		SCR		Nitrogen Injection, SCR	
SO_2 Control	Wet Scrubber		Dry Scrubber		Wet Scrubber		Wet Scrubber		Selexol	
Particulate Control	Baghouse		Baghouse		Baghouse		Baghouse		Good Combustion Practice	
Capital Cost										
Project Capital Cost, 2013 MM$ (w/o Escalation & Owner's Costs)	[redacted]									
Owner's Costs, 2013 MM$ (w/o Escalation and AFUDC)	[redacted]									
Total Project Costs, 2013 MM$	[redacted]									
Total Project Costs, 2013$/kW	[redacted]									
O&M Costs										
Fixed O&M Cost, $/kW-Yr	[redacted]									
Levelized Major Maintenance Cost, $/MWh	[redacted]									
Variable O&M Cost, $/MWh (excl. major maint.)	[redacted]									
Anticipated Operational Emissions Limits, lbs/MMBtu (HHV)										
NO_x	0.04	0.02	0.06	0.03	0.04	0.02	0.04	0.02	0.02	0.02
SO_2	0.04	0.02	0.05	0.03	0.04	0.02	0.04	0.02	0.02	0.01
CO	0.15	0.15	0.10	0.10	0.15	0.15	0.15	0.15	0.05	0.05
CO_2	200	103	200	102	200	105	200	107	200	96
Hg (lb/Tbtu)	0.33	0.28	0.33	0.28	0.34	0.29	0.34	0.29	0.34	0.29
PM/PM10	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.022	0.022
Anticipated Operational Emissions Limits, lbs/MWh										
NO_x	0.360	0.210	0.550	0.320	0.360	0.210	0.350	0.200	0.170	0.210
SO_2	0.360	0.210	0.460	0.270	0.360	0.210	0.350	0.200	0.140	0.090
CO	1.370	1.610	0.920	1.080	1.340	1.570	1.310	1.540	0.440	0.560
CO_2	1820	1100	1840	1100	1780	1100	1740	1100	1790	1100
Hg	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06
PM/PM10	0.300	0.353	0.304	0.357	0.294	0.346	0.287	0.338	0.200	0.250

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As indicated in the preceding tables, the lowest capital cost ($/kW) option is the SCGT option. SCGT technology is typically selected for peaking capacity due to its fast startup times, low construction costs, and shorter project schedule. CCGT is the next lowest capital cost option ($/kW) and is generally selected for intermediate or base-load capacity. CCGT also offers the best heat rate of all the technologies reviewed.

Of the coal technologies, the conventional PC boiler provides the lowest capital cost. Supercritical PC units have the best heat rate of the coal technologies. The heat rate of a supercritical unit is on average 2 percent better than that of a subcritical unit. Since fuel is the primary variable cost of a power plant, a 2 percent decrease in fuel usage is significant. The more efficient supercritical unit will require less fuel and thus generate lower air pollutant emissions (ton/yr) than a comparably sized subcritical unit. IGCC has the highest capital cost ($/kW) of the coal technologies. IGCC is a technology in continued development and various stages of commercialization.

Firing strictly biomass is generally not a viable alternative for large scale power generation (>100 MW) due to the amounts of fuel supply that would be required near the facility. However, 100% biomass firing may be viable for a smaller unit, provided sufficient fuel is available near the site. Biomass co-firing in a PC or CFB boiler can be used to capitalize on the lower emissions levels of biomass fuel while also benefitting from the higher energy content of coal.

Wind turbines are increasingly more common in the utility industry, but do not provide a good option for base-load capacity. Typical capacity factors of wind turbine farms range from 20 to 35 percent, up to an average of 44 percent for locations in the best wind class area.

PV capital costs have declined steadily, but this trend is expected to flatten, and costs remain higher than fossil generation technologies. However, PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals and reduce emissions.

Nuclear power provides a significant portion of the current US power production. However, substantial costs exist in the development of a new unit such as siting, permitting, regulatory and other issues.

* * * * *

2 INTRODUCTION

2.1 General Information

LG&E/KU retained BMcD to evaluate various power generation technologies in support of its integrated resource planning efforts. This assessment is screening-level in nature and includes a comparison of technical features, cost, performance, waste disposal, and emissions of the following technologies at a greenfield site:

NATURAL GAS TECHNOLOGIES

- Simple Cycle Gas Turbine (SCGT)
  - 50 MW Aeroderivative (GE LM6000) SCGT
  - 100 MW Aeroderivative (GE LMS100) SCGT
  - Frame "E-Class" SCGT
  - Frame "F-Class" SCGT
  - 1 MW Microturbine configuration
- Combined Cycle Gas Turbine (CCGT)
  - "F Class" CCGT
  - "Advanced Class" CCGT
  - "Emerging Advanced Class" CCGT
- Spark Ignition Reciprocating Engine
- Fuel Cell

NUCLEAR TECHNOLOGY

- Small Modular Reactor (SMR)

COAL TECHNOLOGIES

- Subcritical Pulverized Coal (PC)
- Subcritical Circulating Fluidized Bed (CFB)
- Supercritical Pulverized Coal (PC)
- Integrated Gasification Combined Cycle (IGCC)

WASTE TO ENERGY TECHNOLOGIES

- Stoker Firing
  - Wood Biomass
  - Municipal Solid Waste (MSW)
  - Refuse Derived Fuel
- Coal / Biomass Co-Firing
  - CFB with 50% biomass / 50% coal
  - PC boiler conversion to 10% biomass / 90% coal
- Internal Combustion
  - Landfill Gas
  - Anaerobic Digestion

RENEWABLE TECHNOLOGIES

- Wind Energy Conversion
- Solar Energy Conversion
- Hydroelectric Energy Conversion

ENERGY STORAGE TECHNOLOGIES

- Pumped Hydroelectric Energy Storage
- Advanced Battery Energy Storage
- Compressed Air Energy Storage (CAES)

It is the understanding of BMcD that information provided in this assessment will be used as preliminary information as part of the Owner's long-term power supply planning process. Any technologies of interest to the Owner should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

2.2 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

* * * * *

3 STUDY BASIS AND ASSUMPTIONS

3.1 Scope Basis and Assumptions Matrix

Scope and economic assumptions used in developing the study are presented in the scope basis and assumptions matrix in Attachment C.

3.2 General Assumptions

General assumptions that govern the technology estimates are shown in Appendix C. The following presents general assumptions that were utilized in this study:

- All estimates are screening level in nature, do not reflect guaranteed costs and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All capital cost and O&M estimates are stated in 2013 “overnight” dollars and are based on EPC contract basis.
- Unless otherwise stated, all options are based on a generic greenfield site in Kentucky with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material.
- Steam Turbines are located indoors.
- The primary fuel for the SCGT and CCGT options is pipeline quality natural gas. These options also include the capability to operate with fuel oil.
- The primary fuel for the coal fired options is Illinois Basin High Sulfur bituminous coal. The coal is assumed to have a heating value of 11,500 Btu/lb with 2.5 percent sulfur content, 10 percent ash content, and 11 percent moisture.
- Coal is assumed to be delivered by barge. A material handling system is included at the site to facilitate delivery via barge.
- Adequate Biomass supply assumed to be delivered to site; biomass processing equipment is excluded from the estimate. Wood waste is assumed to be delivered in the form of wood chips with a mid-moisture content of 30 percent and a heating value of 5,500 Btu/lb.
- Piling is included under heavily loaded foundations.

- Water is assumed to be sourced from surface water or the Ohio River. River intake/discharge structure costs are included in Owner's costs.
- Water, natural gas, and transmission are assumed to be available at the site boundary.
- Waste water is assumed to be delivered to site boundary. Wastewater treatment facilities are excluded from this estimate.
- Demolition or removal of hazardous materials is not included.
- Performance estimates assume new and clean conditions and do not include operating degradation.
- Gas turbine technologies include an evaporative cooler that only operates for ambient conditions of 59°F and above.
- Duct firing is included in the capital costs and performance estimates for combined cycle options.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.

3.3 Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Temporary utilities.
- Performance testing and CEMS/stack emissions testing (where applicable).
- Initial fills and consumables, pre-operational testing, startup, startup management and calibration.
- Construction/startup technical service.
- Site surveys and studies.
- Engineering and construction management.
- Construction testing.
- Operator training.
- Startup spare parts.
- EPC fees and contingency.

3.4 Owner's Costs

The following Owner's costs are included in capital cost estimates:

- Project development.
- Owner's operations, project management, startup engineering personnel.
- Owner's engineering.
- Legal fees.
- Permitting/licensing.
- Project contingency at 5% for screening purposes.
- Builder's risk insurance at 0.45%.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- Switchyard.
- Political concessions/area development fees.
- Permanent plant equipment and furnishings.

3.5 Capital Cost Exclusions

The following costs are excluded from the capital cost estimates:

- Financing fees.
- Interest during construction (IDC).
- Escalation.
- Performance and payment bond.
- Natural gas supply pipeline.
- Sales and property tax.
- Transmission upgrades.
- Water rights.
- Off-site infrastructure.

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3.6 Operations and Maintenance

The following are assumptions and exclusions used for determining the operations and maintenance costs:

- O&M costs are based on a greenfield facility.
- O&M costs are in 2013 USD.
- O&M estimates do not include emissions credit costs, property taxes, or insurance.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication and laboratory expenses.
- Where applicable, variable O&M costs include makeup water, water treatment, water disposal, ammonia, selective catalytic reduction (SCR) replacements, and other consumables not including fuel. Variable O&M costs also include equipment maintenance.
- All solid waste is assumed to be landfilled on-site.
- Performance estimates do not consider degradation over the operating life of the plant.
- O&M costs are based on performance estimates at annual average ambient conditions of 59ºF and 60% relative humidity at 600 feet of elevation.
- Summer performance information is based on 90ºF and 52% relative humidity at 600 feet elevation.
- Winter performance information is based on 20ºF and 60% relative humidity at 600 feet elevation.
- Gas turbine major maintenance assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer (OEM), through the first major inspection.
- Solid waste disposal costs are included at [redacted]/ton for on-site landfill. O&M costs assume all solid waste is landfilled.
- Delivered limestone and pebble lime cost is included at [redacted]/ton and [redacted]/ton, respectively.
- Delivered aqueous ammonia cost is included at [redacted]/ton.

* * * * *

4 NATURAL GAS TECHNOLOGIES

4.1 Simple Cycle Gas Turbine

4.1.1 General Description

An SCGT plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Also, gas turbine manufacturers continue to develop high temperature materials and cooling techniques to allow higher firing temperatures of the turbines, resulting in increased efficiency.

Typically, simple cycle gas turbines are used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have high heat rates compared to combined cycle and coal-fired technologies. Simple cycle gas turbine generation is a widely used, mature technology.

Typical simple cycle plants operate with natural gas as the operating fuel. Often, the ability to operate on fuel oil is also required in case the demand for power exists when the natural gas supply does not. This assessment includes dual fuel capability as an option.

Evaporative coolers are often used to cool the air entering the gas turbine by evaporating additional water vapor into the air, which increases the density of the air, and therefore the mass flow through the turbine. This increases the output of the turbine and is assumed to be installed on all SCGT and CCGT options, and operating at ambient conditions above 59F in this assessment.

4.1.1.1 Aeroderivative Gas Turbines

Aeroderivative gas turbine technology is based on aircraft jet engine design, built with high quality materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and also exhibit shorter ramp up and turndown times, making them ideal for peaking and load following applications.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric (GE), Siemens, Rolls Royce, and Mitsubishi-owned Pratt & Whitney.

This assessment bases aeroderivative performance estimations on the GE LM6000 and LMS100 models, as they are both widely utilized and well known in the marketplace.

4.1.1.2 Frame Gas Turbines

Frame engines are industrial engines, more conventional in design, that are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates when compared to aeroderivative units.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size about 50MW – 330MW. This assessment bases performance estimates on GE models 7EA and 7F-5 for the“E” and “F” turbine classes. The “Advanced Class” gas turbines are not currently marketed for simple cycle application and therefore were not included in this evaluation.

Please see Section 4.2.2 for background on the evolution of the BMcD classes of frame turbines.

4.1.1.3 Microturbines

Microturbines are a relatively new technology with most operating experience in backup and emergency power, combined heat and power (CHP), and distributed generation applications. They are small scale combustion turbine generators typically rated to produce less than 300 kW. For this assessment, performance estimates are based on a multiple unit configuration totaling 1 MW.

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4.1.2 SCGT Performance

The following table provides estimated performance for the simple cycle options evaluated in this analysis. Performance is based on full load operation at average ambient conditions of 59°F and 60% RH at 600 feet of elevation. Evaporative cooling is assumed to be operating for all aeroderivative and frame engine units. Inlet air is assumed to be preheated via recuperated exhaust energy for the microturbine option.

Table 4.1: SCGT Performance Estimates

	1x LM6000	1x LMS100	1x E-Class	1x F-Class	Microturbine
Initial Unit					
Base Load Net Output (kW)	48,700	105,600	86,800	211,200	1,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]				
Add-on Unit					
Base Load Net Output (kW)	48,700	105,600	86,800	211,200	200
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]				

4.1.3 SCGT Emission Controls

Emissions levels and required NO_x and CO controls vary significantly by technology and site constraints. Anticipated emissions levels are shown in Appendix A.

Historically, natural gas SCGT peaking plants have not required post-combustion emissions control systems because they operate at low capacity factors. However, permitting trends suggest post combustion controls may be required depending on the annual number of gas turbine operating hours, proximity of the site to a non-attainment area, and current state regulations. “E” and “F” class gas turbines use dry low NO_x (DLN) combustors to achieve NO_x emissions of 9 parts per million, volumetric dry (ppmvd) at 15 percent O_2 while operating on natural gas fuel. The “F” class gas turbines have high exhaust temperatures compared to the other SCGT options. The high temperatures necessitate a costly tempering air fan system to allow the use of an SCR. It is anticipated that BACT will not require an SCR due to the more costly system. Therefore, an SCR is excluded from the “F” class SCGT option. Due to its lower exhaust temperature, the “E” class units will require SCR/CO control similar to the aeroderivative units.

The aeroderivative units, including the LM6000 PC and LMS100, utilize water injection to achieve NO_x emissions of 25 ppmvd at 15 percent O_2 while operating on natural gas fuel. Because these aero options produce higher levels of emissions, an SCR and CO catalyst is assumed to be required. The SCR will be used to achieve 2 ppmvd NO_x emissions, and the CO will allow for 2 ppmvd of CO at 15 percent excess O_2.

For SCGT units operating on natural gas, uncontrolled CO_2 emissions are estimated to be 120 lb/MMBtu.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Emissions for sulfur dioxide are estimated to be less than 0.01 lb/MMBtu (HHV) for all simple cycle units.

4.1.4 SCGT Water and Waste Disposal

Waste disposal for simple cycle options is negligible. Since the primary fuel to be burned is natural gas, no solid byproducts occur from combustion. Water loss due to Evaporative Cooler blowdown is expected to require raw water makeup of approximately 10 gallons per minute (gpm). The LM6000 and LMS100, which utilize water injection for NO_x control, require an estimated 30 gpm and 100 gpm of water consumption, respectively.

4.1.5 SCGT Land Use Requirements

Land development requirements for SCGT power generation plants vary based on size and configuration of the technology selected. Estimated land usage/output requirements for the SCGT technologies evaluated in this assessment are estimated at 0.006 acres/MW for microturbines, 0.04 acres/MW for aeroderivative units, and 0.08 acres/MW for frame units.

4.1.6 SCGT Start Up Time and Ramp Rates

A desirable attribute of an SCGT is the ability to start and ramp up load quickly. Most manufacturers guarantee ten minute starts, measured from the time the start sequence is initiated

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to when the unit is at 100% load. Starting in less than ten minutes can be achieved but additional maintenance cost may be necessary.

In addition to quick start times, SCGT plants generally add load more quickly than other configurations, though ramp rates vary among different units due to the differences in starting sequence. For example, an SCGT with a 25% per minute ramp rate can ramp up from synchronous idle to full load in four minutes. Loading for the turbines begins once the generator is synchronized with the grid. Thus, the higher the ramp rates, the larger percentage of turbine load that is able to be put on the grid in a shorter period of time.

4.1.7 SCGT Capital Cost Estimate

The project costs for the simple cycle options included in this assessment are shown in Table 4.2 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

Table 4.2: SCGT Capital Cost Estimates

	1x LM6000	1x LMS100	1x E-Class	1x F-Class	Microturbine
Initial Unit					
Project Capital Cost (2013 MM$)	[redacted]				
Owner's Costs (2013 MM$)					
Total Project Costs (2013 MM$)					
Dual Fuel Cost Adder (2013 MM$)					
Add-on Unit					
Project Capital Cost (2013 MM$)	[redacted]				
Owner's Costs (2013 MM$)					
Total Project Costs (2013 MM$)					
Dual Fuel Cost Adder (2013 MM$)					

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4.1.8 SCGT O&M Cost Estimate

O&M costs for the simple cycle options included in this assessment are shown in Table 4.3. Major Maintenance costs vary depending on technology and operational profile. Further detail can be found in Appendix A.

4.1.8.1 Aeroderivatives

Major maintenance costs for aeroderivative engines, representative of the LM6000 and LMS100, are estimated solely on dollar per gas turbine hourly operation ($/GTG-hr) basis and are not affected by number of starts.

4.1.8.2 Frame Engines

Major Maintenance costs for the frame engine, representative of "F class" and "E class" units, are estimated on either a $/GTG-hr or a dollar per gas turbine start ($/GT-start) basis, depending on operational profile. In general, if there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27, maintenance will be start-based.

4.1.8.3 Microturbines

O&M costs associated with microturbines are typically fixed based on maintenance and technical service program agreements at the time of equipment purchase. This evaluation assumes a full maintenance package per manufacturer's recommendations.

Table 4.3: SCGT O&M Cost Estimates

	1x LM6000	1x LMS100	1x E-Class	1x F-Class	Microturbine
Initial Unit					
Fixed O&M ($/kW-yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Major Maintenance ($/GTG-hr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Major Maintenance ($/GTG-Start)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Add-on Unit					
Fixed O&M ($/kW-yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.2 Combined Cycle Gas Turbine

4.2.1 General Description

The basic principle of the Combined Cycle Gas Turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally less than the resultant heat rate from a similarly sized SCGT peaking plant.

The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions. Combined cycle facilities have efficiencies typically in the range of 52 percent to 58 percent on an LHV basis. Gas turbine manufacturers continue to develop high temperature materials to raise the firing temperature of the turbines and increase the efficiency. They are also developing cooling techniques to allow higher firing temperatures.

The continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes, grouped by output and heat rate. For the purposes of this assessment, BMcD is evaluating “F” class turbines (nominal 200 – 240 MW), “Advanced” class turbines (nominal 270-300 MW), and “Emerging Advanced” class turbines (nominal 300+ MW). Though the larger classes are less prominent in the marketplace than the “F” class units, it is important to evaluate the high-level technical and financial differences among all classes.

For this assessment, 1x1, 2x1, and 3x1 power blocks were evaluated with turbines from each class: GE 7F-5 units for “F” class, Mitsubishi 501GAC units for “Advanced” class, and Mitsubishi 501JAC units for “Emerging Advanced” class. Each configuration was modeled in duct fired and non-duct fired configurations, all with wet cooling for heat rejection. The CCGT option assumes natural gas fuel operation and inlet air conditioning utilizing evaporative coolers, with additional costs associated with dual fuel capability shown.

4.2.2 Evolution of Turbine Classes

4.2.2.1 "F Class" Turbines

Each major OEM has incrementally improved on proven frame engine technology platforms to increase output and efficiency while lowering heat rate. However, the "F-class" turbine design modifications have been driven largely toward faster startup times and operational flexibility, including peaking power capabilities and reduced load operation for off peak turn-down.

The GE 7F-5 incorporates efficiency and maintenance improvement design enhancements to its previous technology platform, the 7FA.03 (recently renamed the 7F-3 series). The 7F-5 is based on the same compressor design of the 7F-3 gas turbines, enlarged for higher flow rates to enable greater output. The design also incorporates GE's Dry Low NO_x (DLN) 2.6 combustion system for improved turndown, ramp rate, auto-tuning, and fuel variation capability. Additionally, the turbine section utilizes Advanced Hot Gas Path (HGP) design, aimed to improve output, efficiency, availability, and inspection intervals as a result of improved sealing, reduced clearances, and improved cooling flow. The turbine design includes improved aerodynamic, single crystal material, and loading optimization across blade stages to improve wear modes for low cycle fatigue, oxidation, and creep. A new dovetail blade to rotor construction and a blade health monitoring (BHM) system have been added for improved ease of maintenance.

Siemens has incrementally improved existing platform technology, the SGT6-5000F4, targeting higher output and efficiency. The SGT6-5000F5, also known as the 5000F5(pe), or "Power Enhancement" package, utilizes the same four stage compressor as the 5000F4, with the addition of cooling air and an enlarged compressor inlet. These improvements allow for additional mass flow, yielding higher output while maintaining the same turn-down capability of the 5000F4. The 5000F5(pe) also incorporates the same Ultra-Low NO_x combustion system and turbine stage design as the 5000F4. Siemens has since offered its "Efficiency Enhancement" package, the SGT6-5000F5(ee), which can be retrofit to the original 5000F5. This package includes improved 3D blade optimization at the back end of the compressor section and in the turbine section for improved gas path flow and reduced aerodynamic loss. It also includes the use of pre-swirled cooling air and advanced thermal barrier coatings (TBC) to improve efficiency.

Alstom is actively marketing their improved, Next Generation GT-24 gas turbine. Since the original introduction of the GT-24 in 1996, Alstom has redesigned for operational flexibility and lower emissions, introducing significant upgrades in 2002, 2006, and 2011. Alstom's compressor section has seen several enhancements, including modifications for increased air mass flow, 3D optimization and stage re-staggering of compressor blade and vane design allowing for cooling and leakage improvement, and an increase in variable vane row count for increased turndown ratio. Alstom's platform features sequential, two-stage combustion, which yields low turndown capability (approximately 20% load) while maintaining reduced NO_x emissions and near constant efficiency down to 80% load. The latest GT-24 turbine redesign includes thermal blade coatings and slight increases in firing temperature, as well as 3D airfoil profile optimization, shroud redesign, and a reduction in vane part count per row.

4.2.2.2 "Advanced Class" Turbines

Siemens and MHI were the first OEMs to commercially offer a gas turbine with output in excess of 270 MW. The MHI 501GAC, also referred to as the "GAC", based its design on the G platform originally released in 1997. Design upgrades include a two-bearing rotor support, cold-end drive with axial exhaust, and tangential exhaust bearing strut supports. The GAC utilizes the same 17-stage axial flow compressor as the M501G1. One of the most significant enhancements includes the design of completely air cooled, can-annular Dry Low-NO_x (DLN) combustion system. The use of cooled compressor discharge air eliminates dependence on the steam cycle while yielding similar emissions levels.

Siemens utilized Westinghouse design experience to develop the SGT6-8000H gas turbine, also referred to as the "H". The H utilizes a 13-stage axial compressor with variable guide vanes based on the SGT6-5000F4 platform. The H also utilizes the Ultra-Low NO_x (ULN) combustor system, scaled up from the F4 design. Additionally, pre-swirled cooling air allows for the use of base blade materials with advanced thermal barrier coatings (TBC). Hydraulic Clearance Optimization, a hydraulic rotor shift in axial position by pistons behind the compressor axial bearing, was added to aid prevention of aerodynamic loss.

GE is currently offering the 7F-7 gas turbine which offers approximately 250 MW of output. The 7F-7 features the same compressor from the 7F-5 platform, a new four-stage hot gas path and a modified DLN combustion system with advanced fuel staging. Full speed, full load validation testing is scheduled for 2015 with anticipated first unit commercial operation in 2017.

4.2.2.3 "Emerging Advanced Class" Turbines

The Mitsubishi 501JAC heavy-duty frame industrial gas turbine has been selected to represent the "Emerging Advanced Class" gas turbine technology in this evaluation. The 501JAC gas turbine line is a successor of the earlier M501J gas turbines initially introduced in 2011. The turbine also utilizes DLN combustors to achieve 25 ppmvd NO_x emissions when burning natural gas fuel.

The 501J is assembled from multiple preexisting Mitsubishi Heavy Industries (MHI) subsystems. The compressor is from Mitsubishi's H class gas turbine. The combustors are from the 501G, and the upgrade to the JAC from the J followed a similar path as that of the GAC from the G. The use of cooled compressor discharge air eliminates dependence on the steam cycle while yielding similar emissions levels. The turbine section of the 501JAC was developed for the Japanese National Project, and then modified to fit the lower firing temperatures of the "J"-class turbines.

4.2.3 CCGT Performance

The following table provides estimated performances for the CCGT technology evaluated in this assessment. Performances are based on full load operation at average ambient conditions of 59^{o}F and 60% RH at 600 feet of elevation. Evaporative cooling is assumed to be operating at temperatures above 59^{o}F. The steam turbine of a fired plant is designed such that optimal efficiency is achieved with the additional steam flow resulting from duct firing. As such, when operating in unfired mode, a fired plant will be operating at less than optimal performance compared to a plant designed for unfired operation. Therefore, an unfired plant has a better heat rate compared to a fired plant operating in the unfired mode. This trend can be seen in Table 4.4. Further performance detail can be found in Appendix A.

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Table 4.4: CCGT Performance Estimates

	F-Class		Advanced Class		Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
1x1 Plant Configuration						
Base Load Net Output (kW)	315,100	311,900	397,400	393,600	441,100	437,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]					
Incremental Duct Fired Net Output (kW)	N/A	45,200	N/A	58,000	N/A	65,500
Incremental Duct Fired Net Heat Rate (HHV Btu/kWh)	[redacted]					
2x1 Plant Configuration						
Base Load Net Output (kW)	637,600	628,400	796,100	785,200	883,600	871,900
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]					
Incremental Duct Fired Net Output (kW)	N/A	90,400	N/A	116,100	N/A	130,900
Incremental Duct Fired Net Heat Rate (HHV Btu/kWh)	[redacted]					
3x1 Plant Configuration						
Base Load Net Output (kW)	960,400	946,400	1,198,800	1,182,300	1,330,400	1,312,700
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]					
Incremental Duct Fired Net Output (kW)	N/A	135,700	N/A	174,100	N/A	196,300
Incremental Duct Fired Net Heat Rate (HHV Btu/kWh)	[redacted]					

4.2.4 CCGT Emissions Control

The "F-class" gas turbines can achieve NO_x emissions at 9 to 15 ppmvd down to 40 to 50 percent load. The "Advanced class" gas turbine emission rate is 15 to 25 ppmvd down to 50 percent load. The "Emerging Advanced class" gas turbine emission rate is 20 to 30 ppmvd down to 50 percent load. An SCR will be required for the CCGT option to lower NO_x emissions to 2 ppmvd at 15 percent excess O_2. The estimated emissions rate for NO_x is 0.01 lb/MMBtu. It is anticipated that a CO catalyst will also be required to reduce CO emissions. This assessment assumes CO emissions will be controlled to 2 ppmvd CO at 15 percent O_2.

The use of an SCR and CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with NO_x molecules. This requires on-site ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this assessment.

For all CCGT options, CO_2 emissions are estimated to be 120 lb/MMBtu.

PM10/2.5 emissions are approximately 0.01 lb/MMBtu for CCGT technologies. These amounts include emissions from the gas turbines, front and back filterable and non-filterable, but do not include any particulates due to salt formation in the HRSG caused by oxidation. SCR and CO catalysts increase sulfur oxidation rates which can further increase PM10/2.5 emissions. This limit is highly dependent on the sulfur content of the gas as well as SCR and CO catalyst design.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions of a CCGT plant are very low compared to coal technologies. The emission rate of sulfur dioxide for a combined cycle unit is estimated to be less than 0.01 lb/MMBtu.

4.2.5 CCGT Water and Waste Disposal

Operational waste disposal is negligible. Since the fuel to be burned is natural gas, no solid byproducts occur from the combustion. The only waste disposal to be addressed is the disposal of the blow-down water, the amounts of which are shown in Table 4.5 below. Water is assumed to be sourced from surface water from the Ohio River. Intake structure costs are listed as an Owner's cost in Appendix A. Costs associated with the transport of water from the source to plant equipment are excluded from this assessment. This assessment also excludes costs associated with or delivery to a wastewater treatment facility provided by others.

Table 4.5: CCGT Blowdown Water Estimates

	F-Class		Advanced Class		Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
1x1 Plant Configuration						
Blowdown Water, MMgal/year	370	420	420	470	530	580
Blowdown Water, gpm	700	800	800	900	1,000	1,100
2x1 Plant Configuration						
Blowdown Water, MMgal/year	740	840	840	950	1,050	1,160
Blowdown Water, gpm	1,400	1,600	1,600	1,800	2,000	2,200
3x1 Plant Configuration						
Blowdown Water, MMgal/year	1,100	1,260	1,260	1,420	1,580	1,730
Blowdown Water, gpm	2,100	2,400	2,400	2,700	3,000	3,300

4.2.6 CCGT Land Use Requirements

Land development requirements for CCGT power generation plants vary based on size and configuration of the gas turbine selected. Estimated land usage/output requirements for the CCGT technologies evaluated in this assessment range from approximately 0.06 acres/MW to 0.09 acres/MW.

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4.2.7 CCGT Capital Cost Estimate

Table 4.6 shows the estimated capital costs for the CCGT technologies evaluated included in this assessment. Section 3 of this evaluation provides the assumptions used to develop this estimate. Capital cost excludes interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

Table 4.6: CCGT Capital Cost Estimates

	F-Class		Advanced Class		Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
1x1 Plant Configuration						
Project Capital Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Owner's Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Project Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2x1 Plant Configuration						
Project Capital Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Owner's Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Project Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3x1 Plant Configuration						
Project Capital Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Owner's Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Project Costs (2013 MM$)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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4.2.8 CCGT O&M Cost Estimate

The estimated O&M expenses for the CCGT technologies evaluated in this assessment are shown in Table 4.7. Note that major maintenance costs vary significantly by OEM and operational profile. In general, major maintenance for the frame units will be dependent on hours per start. If there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27, the maintenance will be starts based. Additional detail can be found in Appendix A.

Table 4.7: CCGT O&M Cost Estimates

	F-Class		Advanced Class		Advanced Class	
Duct Firing Description	Unfired	Fired	Unfired	Fired	Unfired	Fired
1x1 Plant Configuration						
Fixed O&M ($/kW-yr)	[redacted]					
Major Maintenance ($/GTG-hr)						
Major Maintenance ($/GTG-Start)						
Variable O&M ($/MWh)						
Incremental Duct Fired Variable O&M ($/MWh)						
2x1 Plant Configuration						
Fixed O&M ($/kW-yr)	[redacted]					
Major Maintenance ($/GTG-hr)						
Major Maintenance ($/GTG-Start)						
Variable O&M ($/MWh)						
Incremental Duct Fired Variable O&M ($/MWh)						
3x1 Plant Configuration						
Fixed O&M ($/kW-yr)	[redacted]					
Major Maintenance ($/GTG-hr)						
Major Maintenance ($/GTG-Start)						
Variable O&M ($/MWh)						
Incremental Duct Fired Variable O&M ($/MWh)						

4.3 Reciprocating Engine

4.3.1 General Description

The reciprocating, or piston, engine operates on the four-stroke Otto cycle for the conversion of pressure into rotational energy. Fuel and air are injected into a combustion chamber prior to its compression by the piston assembly of the engine. A spark ignites the compressed fuel and air mixture causing a rapid pressure increase that drives the piston downward. The piston is connected to an offset crankshaft, thereby converting the linear motion of the piston into rotational motion that is used to turn a generator for power production. By design cooling systems are typically closed-loop, minimizing water consumption. Emission control is generally accomplished via lean cycle combustion through fuel to air ratio control, although traditional secondary control options are available, such as SCR equipment.

Many different vendors, such as Wärtsilä, Fairbanks Morse, Caterpillar, Kawasaki, Mitsubishi, etc. offer reciprocating engines and they are becoming popular as a means to follow wind turbine generation with their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and quick start up.

The Wärtsilä 18V50DF (Dual fuel) reciprocating engine was evaluated in this assessment as potential candidate for a simple cycle facility. The Wärtsilä 18V50DF engine can accommodate a wide range of fuels, including natural gas and light or heavy fuel oil, and achieves stable, high efficiency across the ambient range. These heavy duty, medium speed, four-stroke combustion engines are easily adaptable to grid-load variations, such as wind generation fluctuation.

4.3.2 Engine Performance

The following table provides estimated performance for the reciprocating engine options evaluated in this analysis. Performance is based on full load operation at average ambient conditions of 59^{o}F and 60% RH at 600 feet of elevation. Further performance detail can be found in Appendix A.

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Table 4.8: Engine Performance Estimates

	6x 18V50DF	Add-on
Base Load Net Output (kW)	100,200	16,700
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]	[redacted]

4.3.3 Engine Land Use Requirements

Estimated land usage/output requirements for the reciprocating engine technologies evaluated in this assessment are estimated at 0.03 acres/MW.

4.3.4 Engine Emissions Control

In addition to good combustion practices, reciprocating engines often employ SCR and CO catalysts to control NO_x and CO emissions. An SCR may be required for reciprocating engine simple cycle operation depending on operating hours and site permitting constraints. Operation on natural gas fuel with an SCR yields reduction of NO_x emissions to 5 ppmvd at 15 percent excess O_2, while a CO catalyst results in anticipated emissions of 15 ppmvd. An SCR and CO catalyst are included in this assessment. For engines operating on natural gas, CO_2 emissions are estimated to be 120 lb/MMBtu.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Emissions for sulfur dioxide are estimated to be less than 0.01 lb/MMBtu (HHV) for simple cycle units.

4.3.5 Engine Water and Waste Disposal

Waste disposal for reciprocating engine options is negligible. Since the primary fuel to be burned is natural gas, no solid byproducts occur from combustion.

4.3.6 Engine Capital Cost Estimate

The project costs for the 6x Wärtsilä 18V50DF option included in this assessment are shown in Table 4.9 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

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Table 4.9: Engine Capital Cost Estimates

	6x 18V50DF	Add-on
Project Capital Cost (2013 MM$)	[redacted]	[redacted]
Owner's Costs (2013 MM$)	[redacted]	[redacted]
Total Project Costs (2013 MM$)	[redacted]	[redacted]

4.3.7 Engine O&M Cost Estimate

O&M costs for the reciprocating engine options included in this assessment are shown in Table 4.10 below. Further detail can be found in Appendix A.

Table 4.10: Engine O&M Cost Estimates

	6x 18V50DF	Add-on
Fixed O&M ($/kW-yr)	[redacted]	[redacted]
Major Maintenance ($/GTG-hr)	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]

4.4 Fuel Cell

4.4.1 General Description

Fuel cells consist of an electrolyte material held between a negatively charged anode and a positively charged cathode, which is then placed between two flow field plates. Via the flow plates, hydrogen fuel is forced through the anode while oxygen (air) flows through the cathode. The resultant chemical reaction splits the hydrogen into particles by charge. The electrolyte is impermeable to the negatively charged particles, which are then forced through a circuit, generating current. Positively charged particles pass through the electrolyte and recombine with oxygen and the negatively charged particles at the anode to form water and carbon dioxide byproducts. This process also yields heat which can be recuperated to generate high temperature steam used in the reformation of natural gas to produce the hydrogen fuel.

4.4.1.1 Molten-Carbonate Fuel Cells

Molten-carbonate fuel cells (MCFCs) utilize a high temperature salt (typically sodium or magnesium) based electrolyte core. The electrolyte compound is held in molten state, operating at 1,100 to 1,300 degrees Fahrenheit. While this yields relatively high thermal efficiencies in the range of 50%-60%, the elevated temperatures also result in increased corrosiveness of the liquid electrolyte, with both parameters placing severe constraints on stability and life of cell components. This type of facility also requires additional balance of plant equipment not required in solid electrolyte type cells. MCFCs are currently being marketed as commercially available technology for small power generation needs, however MCFCs are considered a young generation technology with little operational experience compared to simple cycle turbine and engine technologies. Research and development is still ongoing for use in utility power generation to increase size and reliability and to decrease cost of manufacture.

4.4.1.2 Solid Oxide Fuel Cells

Solid Oxide fuel cells (SOFCs) utilize a solid ceramic and metal oxide based electrolyte but operate at even higher temperatures than the MCFC, in the range of 1,200 to 1,800 degrees Fahrenheit at similar thermal efficiencies. Elevated operating temperatures yield the possibility of internal gas reformation and makes this technology ideally suited for steam co-generation applications, but can also impose site constraints and limit cell component life. SOFCs are commercially available, but they are a relatively recent development in fuel cell technology with relatively limited operating experience.

Research and development continues in both private and government funded institutions in an effort to bring the cost of fuel cells to a competitive level. There may be buy-down programs or other state offered incentives that can reduce the installed cost of fuel cells. Currently, SOFCs are only commercially available in 300kW output modular units that can be stacked in series to increase power output.

Due to the configuration of the cell and electrolyte core, MCFCs are more commonly scalable and are commercially available in modular units of near 3000 kW output. This scalability lends the MCFC to better suitability for distributed generation applications at the utility scale,

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particularly in excess of one to two megawatts of output. Recent domestic SOFC installations have trended more towards single consumer use at large company headquarters, rather than for the sole purpose of power generation and sale to the grid. In addition, manufacture of SOFCs is limited, which has led to high cell cost and concern over product value. For the purposes of this assessment, a multiple-unit MCFC configuration has been assumed as representative fuel cell technology.

4.4.2 Fuel Cell Performance

The reference fuel cell used in this evaluation is capable of producing 2.8 MW per module. For purposes of this evaluation, a four module facility producing 11.2 MW with a heat rate (HHV) of [redacted] Btu/kWh was assumed.

4.4.3 Fuel Cell Land Use Requirements

The area of land required for a fuel cell facility is estimated at 0.08 acres/MW.

4.4.4 Fuel Cell Emissions Control

The nature of fuel cell operation (lack of combustion) lends itself to inherently low emissions levels, thus emissions control equipment is not required. CO_2 is the only significant emission resulting from fuel cell operation, estimated to be 120 lb/MMBtu.

4.4.5 Fuel Cell CCGT Water and Waste Disposal

Waste disposal resulting from fuel cell operation is negligible. Since no combustion occurs, no solid byproducts are generated. Fuel cells are estimated to consume 9 gpm of water and discharge 4.5 gpm per module. Wastewater treatment is not considered to be required and is excluded.

4.4.6 Fuel Cell Capital Cost Estimate

The estimated capital cost of an 11.2 MW fuel cell facility is [redacted]/kW, based on the nominal average ambient net unit output of 11.2 MW. The estimated capital cost for a 2.8 MW add-on unit is [redacted]/kW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

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4.4.7 Fuel Cell O&M Cost Estimate

The O&M estimates for a fuel cell facility are as follows: fixed O&M costs of [redacted]/kW-yr and variable O&M and major maintenance costs are included in the fixed O&M costs.

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5 COAL TECHNOLOGIES

5.1 Pulverized Coal

5.1.1 General Description

Pulverized Coal (PC) steam generators are characterized by the fine processing of the coal for combustion in a suspended fireball. Coal is supplied to the boiler from bunkers that direct coal into pulverizers, which crush and grind the coal into fine particles. The primary air system transfers the pulverized coal from the pulverizers to the steam generator's low NO_x burners for combustion. Two types of burner arrangements for pulverized coal units are wall fired and tangentially fired (T-fired). Wall fired burners are more common and involve multiple burners arranged in rows up the side of a boiler wall. In T-fired burner arrangements, rows of burners are located in the corners of a boiler. Each type of arrangement burns the coal in the middle elevation of the boiler in suspension. This is also referred to as a suspended fireball and, along with the fine coal particle size, is characteristic of pulverized coal combustion. PC technology is a mature and reliable energy producing technology used around the world.

The steam generator produces high-pressure steam for throttle steam to the steam turbine generator. The steam expansion provides the energy required by the steam turbine generator to produce electricity. A portion of the steam exits the turbine through extractions and flows to the feedwater heaters and may feed boiler feedwater pump turbines.

The power industry typically classifies conventional coal fired power plants as subcritical, supercritical, and ultra-supercritical based on the steam operating pressure. Subcritical units operate below the critical point of water, which is 3208 psia and 705°F, supercritical units operate above the critical point of water. Ultra-supercritical units operate at even higher pressures or temperatures in order to increase efficiency. While efficiency is increased, higher grade and thicker materials must be used, which increase costs.

At pressures above the critical point of water, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. Due to the increased steam pressures and temperatures, supercritical and ultra-supercritical units are generally more efficient than subcritical units of the same size resulting in fuel savings and decreased emissions.

Since the start of the 1980s, the majority of problems relating to operating PC units at elevated steam conditions have been resolved. Development of high strength materials has helped to mitigate the problem of thermal stresses in the early units. The development of Distributed Control Systems (DCS) has helped make a complex starting sequence much easier to control and minimized tube overheating due to lack of fluid. The newer units also use a particle separator placed into the fluid process during startup to minimize solid particle carryover, which causes erosion of the turbine blades.

Most modern PC plants are operated at supercritical steam conditions because of the efficiency and emissions improvements compared to subcritical plants. If PC technology is chosen as the best technology to further develop, a more detailed study shall be performed to evaluate the optimal steam cycle. Evaluations have shown that there are technical and economic constraints to supercritical PC unit minimum size. Units near 400 MW and below typically incur prohibitive tube velocities and require prohibitively expensive materials to handle stress and erosion issues. The PC technologies evaluated for this assessment include a 500 MW subcritical PC plant and both 500 MW and 750 MW supercritical PC units. All PC units are assumed to burn Illinois basin high sulfur bituminous coal with wet cooling towers for heat rejection. Units in this size range would typically consist of one boiler and one steam turbine.

5.1.2 PC Carbon Capture Technology

Proposed GHG regulations will limit CO_2 emissions to 1,000 lbs/MWh, a level which would require carbon capture on PC plants. Carbon capture has been demonstrated in the field, but not at the scale that would be necessary for utility generation. As the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. In the meantime, however, early adopters may be subject to significant cost and performance risks.

All PC plants in this assessment include an option for CO_2 capture using the advanced amine process. The advanced amine process is an enhancement on the Monoethylamine (MEA) process that was developed over 60 years ago. The process has since been adapted to treat flue gas streams for CO_2 capture. Other organic chemicals belonging to the family of compounds known as “amines” are now being used to reduce cost and power consumption as compared to the traditional MEA solvent.

In the advanced amine process, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger, and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added as make up for losses incurred in the process.

5.1.3 PC Performance

The following table provides performance estimates for the PC technologies evaluated in this assessment. Performance is based on full load operation at average ambient conditions of 59^{o}F and 60% RH at 600 feet of elevation when burning Illinois basin high sulfur bituminous coal. The addition of the advanced amine process significantly increases the net plant heat rate (reduces efficiency). This is due to an increase in auxiliary power requirements of the induced draft fans to push flue gas through a longer distance of ductwork. A significant percentage of low pressure steam is extracted for the amine solvent regeneration process, thereby increasing the steam turbine heat rate and severely impacting net plant performance. Additional auxiliary power is required by solvent circulation equipment, CO_2 compression equipment, and other miscellaneous equipment associated with the CO_2 capture process. CO_2 compression of up to 2000 psig is included. Further performance detail can be found in Appendix A.

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Table 5.1: Pulverized Coal Performance Estimates

	Subcritical		Supercritical			
	500 MW		500 MW		750 MW	
Carbon Capture Description	None	CC	None	CC	None	CC
Base Load Net Output (kW)	500,000	425,000	500,000	425,000	750,000	637,500
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]					

5.1.4 PC Land Use Requirements

Estimated land usage/output requirement for the PC technologies evaluated in this assessment is 1.1 acres/MW. Carbon capture technology would essentially double the size of the power block, adding about 10% to the total required land area.

5.1.5 PC Emissions Control

NO_x emissions are controlled with combustion and post-combustion controls such as staged combustion in the form of low NO_x burners with separated overfire air and an SCR system. The SCR system will reduce NO_X emissions to an anticipated limit of 0.04 lb/MMBtu. 19% aqueous ammonia is assumed as the SCR reagent. Carbon capture equipment is expected to contribute to additional NO_x emissions reductions to 0.02 lb/MMBtu.

SO_2 control on a PC unit is accomplished through the use of a dry or wet flue gas desulfurization (FGD) system. A dry FGD system can achieve approximately 95 percent removal and a wet FGD system can achieve up to and exceed 98 percent removal. A wet FGD is assumed to be installed for a PC boiler burning Illinois basin coal to control SO_2 emissions to 0.04 lb/MMBtu. The addition of carbon capture equipment yields additional SO_2 emissions reduction to 0.02 lb/MMBtu.

This evaluation also includes a baghouse to remove particulate from the flue gas and a sorbent injection system to control acid gases.

Test information indicates that the inherent mercury control provided by a fabric filter followed by a wet limestone scrubber is adequate to achieve 90 percent removal. At this time it is uncertain whether or not equipment manufacturers are willing to provide commercial guarantees to this level of mercury control. Therefore, the capital cost for a contingent carbon injection system has been included.

For PC plants burning Illinois basin coal with the discussed emissions control equipment, carbon capture technology is anticipated to reduce CO_2 emissions to 1,100 lb/MWh of electricity produced.

5.1.6 PC Water and Waste Disposal

With the installation of a wet FGD, the process byproducts are limestone sludge or gypsum (with a forced oxidation system), bottom ash and fly ash. The fly ash can be utilized in the manufacturing of concrete and the gypsum produced by a wet FGD system can be used for making wall board. A site market analysis is required to determine potential markets for these wastes. However, the byproducts may not be marketable if they contain high amounts of mercury, so these levels should be factored into the market study. In most cases, the byproducts are disposed in a landfill. For the purpose of this analysis, it was assumed a market would not be developed and an on-site landfill has been included. Waste water resulting from plant operation is assumed to be delivered to site boundary and treatment costs have been excluded from the estimate.

Estimated water consumption for a 500 MW PC facility with and without carbon capture is 4,750 gpm and 3,650 gpm, respectively. For a 750 MW PC facility with and without carbon capture, estimated water consumption is 7,110 gpm and 5,470 gpm, respectively.

5.1.7 PC Capital Cost Estimate

The project costs for the PC options included in this assessment are shown in Table 5.2 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

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Table 5.2: Pulverized Coal Capital Cost Estimates

	Subcritical		Supercritical			
	500 MW		500 MW		750 MW	
Carbon Capture Description	None	CC	None	CC	None	CC
Project Capital Costs (2013 MM$)	[redacted]					
Owner's Costs (2013 MM$)						
Total Project Costs (2013 MM$)						

5.1.8 PC O&M Cost Estimate

The estimated O&M expenses for the PC technologies evaluated in this assessment are shown in Table 5.3. Additional detail can be found in Appendix A. Major maintenance costs include costs for work typically conducted during plant outages, steam turbine overhauls, major boiler replacements, fabric filter bag replacements, SCR catalyst replacements and water treatment system replacements. Scheduled outages for PC technology assume a 2 week outage each year for the boiler. Additionally, the entire facility will undergo an outage of approximately 6 weeks every 5 years, during which time, steam turbine major maintenance will be performed. If carbon capture equipment is included, additional staff will be required to operate and maintain equipment for both the advanced amine process and the CO_2 compression. Increased variable O&M is largely attributed to the Advanced Amine reagent make-up cost.

Table 5.3: Pulverized Coal O&M Cost Estimates

	Subcritical		Supercritical			
	500 MW		500 MW		750 MW	
Carbon Capture Description	None	CC	None	CC	None	CC
Fixed O&M ($/kW-yr)	[redacted]					
Major Maintenance ($/MWh)						
Variable O&M ($/MWh)						

5.2 Circulating Fluidized Bed

5.2.1 General Description

The combustion process within a CFB boiler occurs in a suspended or fluidized bed of solid particles. The solid particles are a mixture of fuel, ash products from prior combustion, and some form of inert material such as sand, slag, etc. The boiler operates by blowing air into the boiler through air nozzles in the bottom as fuel is injected into the furnace, thereby creating a fluidized bed of material. As combustion takes place, smaller particles are carried out of the boiler and collected by solid separators. This material is circulated back into the bottom of the furnace to combine with the large particles that did not get carried out, and provides the ignition source for the new fuel being fed into the unit. CFB combustion is a mature technology with inherently low emission rates compared to pulverized coal combustion.

Due to the combustion process, CFB technology is well suited to burn fuels with large variability in constituents. Deviations in fuel type, size, and heat content have minimal effect on the furnace performance characteristics. Unlike pulverized coal units, CFB units do not require tuning of the burners for each fuel to obtain the appropriate air fuel mixture and optimal settings. Sites with access to abundant sources of fuels that vary significantly in constituents or that present combustion challenges to other boiler types are typically good prospects for CFB plants.

The largest CFB boiler currently in operation is a 460 MW unit in Southern Poland, with plans for 550 MW units under development for construction in Korea. Aside from being the largest, these plants are also the world’s first to employ supercritical CFB technology. All other CFB boilers built to date are designed for subcritical operation in the 250 MW – 300 MW size range. The largest units currently operating in the United States are two 300 MW Jacksonville Electric Authority repowered units designed to fire any combination of pet coke and bituminous coal.

Typical CFB designs for units larger in capacity than 300MW are comprised of multiple boilers with a single steam turbine. For example, the most cost effective configuration for a 600 MW facility is typically two 300 MW boilers supplying steam to a single turbine. Therefore, when larger (greater than 300MW) scale generation is required, the CFBs will have some disadvantage in increased capital costs compared to technologies such as PC units that can utilize single

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boilers. For this reason, CFB units are optimally sized at the 250-300 MW range, the 500-600MW range, etc. This assessment assumes an arrangement comprised of two 250 MW boilers and a single steam turbine.

5.2.2 CFB Carbon Capture Technology

The CFB plant in this assessment includes an option for CO_2 capture using the advanced amine process. Refer to Section 5.1.2 for further information on this process.

5.2.3 Circulating Fluidized Bed Performance

The following table provides performance estimates for the CFB plant evaluated in this assessment. Performance is based on full load operation at average ambient conditions of 59°F and 60% RH at 600 feet of elevation when burning Illinois basin high sulfur bituminous coal. Though CFB units typically have higher boiler efficiencies than similarly sized PC units, some of this gain is offset by the higher auxiliary load associated with increased pressure drops. Further performance detail can be found in Appendix A. As with PC boiler technology, the addition of an advanced amine process increases the net plant heat rate due to greater auxiliary power and steam extraction requirements.

Table 5.4: CFB-Coal Fired Performance Estimates

	2x250 MW	
Carbon Capture Description	None	CC
Base Load Net Output (kW)	500,000	425,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]	

5.2.4 Circulating Fluidized Bed Land Use Requirements

Estimated land usage/output requirement for the PC technologies evaluated in this assessment is 0.7 acres/MW. Carbon capture technology would essentially double the size of the power block, adding 5%-10% to the total required land area.

5.2.5 Circulating Fluidized Bed Emissions Control

The CFB combustion process yields inherently low NO_x emissions, while some SO_2 emissions are removed by limestone in the furnace. CO emissions are assumed to be uncontrolled.

This assessment includes the installation of a Selective Non-Catalytic Reduction (SNCR) system to further reduce NO_x emissions by up to approximately 80% beyond base configuration, utilizing aqueous ammonia as the assumed SNCR reagent. Anticipated NO_x emissions levels are 0.06 lb/MMBtu, while the addition of carbon capture equipment is expected to contribute some additional reduction to 0.03 lb/MMBtu.

The most economical and efficient form of additional SO_2 removal on a CFB is a polishing dry FGD. Dry scrubbing involves spraying an atomized solution of an alkaline reagent, typically lime-based, into hot flue gas for the absorption of SO_2. Moisture in the spray then evaporates so that the absorbed SO_2 is carried in suspension out of the boiler and collected in the baghouse filtration system. SO_2 emissions must be reduced to 1 ppm for the CO_2 absorption process. The assessment assumes it is cost effective to increase FGD efficiency to achieve 7 ppm SO_2 emissions, and use a caustic wash to further reduce SO_2 to 0.05 lb/MMBtu.

An option is included within this assessment for the installation of a sorbent injection system to control mercury emissions, resulting in an anticipated 80% reduction over base configuration. The mercury laden sorbent material is assumed to be collected by the baghouse.

This estimate assumes carbon capture is adequate to meet permitting constraints, down to 1,100 lb/MWh.

5.2.6 Circulating Fluidized Bed Water and Waste Disposal

With the installation of a dry polishing FGD, the process byproducts are bottom ash and fly ash. The fly ash can be utilized in the manufacturing of concrete should a market exist within the area, though high levels of mercury within the fly ash may negate marketability. In most cases, the byproducts are disposed in a landfill. For the purpose of this analysis, it was assumed a market would not be developed and an on-site landfill has been included. Waste water resulting from plant operation is assumed to be delivered to site boundary and treatment costs have been excluded from the estimate.

Estimated water consumption for a 500 MW (2x250 MW configuration) CFB facility with and without carbon capture is 4,750 gpm and 3,650 gpm, respectively.

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5.2.7 Circulating Fluidized Bed Capital Cost Estimate

The project costs for the CFB options included in this assessment are shown in Table 5.5 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

Table 5.5: CFB-Coal Fired Capital Cost Estimates

	2x250 MW	
Carbon Capture Description	None	CC
Project Capital Costs (2013 MM$)	[redacted]	
Owner's Costs (2013 MM$)		
Total Project Costs (2013 MM$)		

5.2.8 Circulating Fluidized Bed O&M Cost Estimate

The estimated O&M expenses for the CFB technologies evaluated in this assessment are shown in Table 5.6. Additional detail can be found in Appendix A. The quantities of combustion products generated by a CFB plant with a dry FGD system will be higher than those from a PC plant with a wet FGD system due to differences in plant efficiencies and limestone consumption rates. Further, the refractory in a CFB drives the boiler maintenance costs higher for two CFB boilers compared to one PC boiler.

If carbon capture equipment is included, additional staff will be required to operate and maintain equipment for both the advanced amine process and the CO_2 compression. Increased variable O&M is largely attributed to the Advanced Amine reagent make-up cost.

Table 5.6: CFB-Coal Fired O&M Cost Estimates

	2x250 MW	
Carbon Capture Description	None	CC
Fixed O&M ($/kW-yr)	[redacted]	
Major Maintenance ($/MWh)		
Variable O&M ($/MWh)		

5.3 Integrated Gasification Combined Cycle

5.3.1 General Description

The Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste that can be fired in a combined cycle power plant. The gasification process itself is a proven technology used extensively for chemical production of products such as ammonia for fertilizer. The gasification process links solid fossil fuels such as coal and existing gas turbine technology. Integrating proven gasifier technology with gas turbine combined cycle technology is fairly new and continues to improve with additional project experience. There are currently six IGCC plants that have either been built, are in construction, or are in the development phase within the United States. Summit Power – Texas Clean Energy Project and Hydrogen Energy California are in the development stages, Mississippi Power – Kemper Co. is under construction, and Duke Energy – Edwardsport, Tampa Electric – Polk and Wabash Valley Power – Wabash River have been completed. IGCC is considered beneficial because it can remove certain pollutants prior to combustion resulting in lower emissions compared to other coal technologies.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

5.3.1.1 Entrained Flow

The entrained flow gasifier reactor design converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. GE, Phillips 66, Siemens, and Shell produce entrained flow gasifiers.

5.3.1.2 Fluidized Bed

Fluidized-bed reactors are highly back-mixed and efficiently mix feed particles with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The Kellogg-Brown-Root (KBR), Kellogg-Rust-Westinghouse (KRW), and High Temperature Winkler designs use fluidized bed technology.

5.3.1.3 Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with oxygen moving up through the bed. Moving-bed gasifiers are also not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design used at both the Dakota Gasification plant for production of substitute natural gas (SNG) and the South Africa Sasol plant for production of liquid fuels. The BGL gasification process also includes a moving bed gasifier design.

Entrained flow is the most widely used gasification process, and therefore is used as the basis of this assessment. Pulverized coal in conjunction with oxygen from an air separation unit (ASU) feed into the gasifier at around 600 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400°F where it then cools to less than 400°F in a syngas cooler. The heat recovery processes generates a large quantity of steam. Steam is used within the gasification block and for integration with the combined cycle power block, where additional power is produced by the steam turbine. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system, typical of those utilized in chemical production gasifiers. Upon exiting the syngas cooler, the syngas enters scrubbers which remove particulates, mercury, ammonia (NH3), hydrogen chloride and other alkali components. Hydrogen sulfide (H_2S) is removed from the syngas stream by conventional acid gas removal (AGR) technologies, such as a SELEXOL scrubbing unit explained in the next section. The removed acid gas stream is processed in a sulfur recovery unit (SRU), such as a standard Claus unit, which produces elemental sulfur. The cooled, cleaned, sweet syngas flows into a modified combustion chamber of a gas turbine specifically designed to accept the low calorie syngas. Combustion in the turbine generates hot exhaust gas. This hot exhaust gas enters a heat recovery steam generator which recovers excess heat from the gas turbine exhaust to produce steam for the steam turbine and gasification process.

5.3.2 IGCC Carbon Capture Technology

The benefit of IGCC is that CO_2 can be captured from the syngas coming out of the gasifier before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 percent volume) and at high pressure, offering the opportunity for a lower cost for capture. CO_2 capture in an IGCC facility is accomplished by removing the CO_2 from the syngas prior to combustion by first shifting the syngas to convert CO to CO_2 and H_2 by the addition of water-gas shift reactors. The CO_2 is then absorbed in the AGR unit, resulting in a hydrogen rich fuel.

Solvents such as SELEXOL and RECTISOL are typically used in the pre-combustion CO_2 capture process. The IGCC option in this study is evaluated utilizing the SELEXOL scrubbing process to accomplish pre-combustion carbon capture. The SELEXOL solvent is a dimethyl ether of polyethylene glycol. It is a physical solvent selective to both H_2S and CO_2. As such, it makes an excellent choice for the IGCC technology. The COS/HCN hydrolysis reactor included in the IGCC facility is replaced with a sour water-gas shift reactor that converts the carbon monoxide to CO_2 and hydrogen fuel. In the AGR, the syngas is routed through both an H_2S absorber and a CO_2 absorber. The H_2S is removed from the solvent by heat, and the CO_2 rich solvent is run through flash tanks, where the CO_2 is released by reduction in pressure. The CO_2 comes off at relatively low pressure and temperature. For the CO_2 capture case, compression has been included. Additional treatment and drying of the CO_2 may be required for transportation and sequestration depending on the final purity requirements.

5.3.3 IGCC Performance

The following table provides estimated performances for the IGCC technology evaluated in this assessment. Performances are based on full load operation at average ambient conditions of 59^oF and 60% RH at 600 feet of elevation when utilizing Illinois basin high sulfur bituminous coal as feedstock. Further performance detail can be found in Appendix A. The process shift reaction results in a high hydrogen content fuel with a higher heating value (Btu/lb) than for the standard syngas cases. This results in less mass flow through the gas turbines and less gas turbine power as a result. Additionally, acid gas removal equipment requires a large quantity of IP steam extraction, resulting in less steam turbine output. In addition, the auxiliary load increases with the addition of CO_2 compression equipment. Increased auxiliary loads result in a reduction of net plant output and an increase in net plant heat rate.

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Table 5.7: IGCC Performance Estimates

	2x1	
Carbon Capture Description	None	CC
Base Load Net Output (kW)	618,000	482,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]	

5.3.4 IGCC Land Use Requirements

The area of land required for an IGCC power plant is estimated at 1.2 acre/MW for a 2x1 facility. Carbon capture technology would essentially double the size of the power block, adding about 15% to the total required land area.

5.3.5 IGCC Emissions Control

Emissions controls are anticipated to be required to control NO_x emissions to 0.019 lb/MMBtu and SO_2 emissions to 0.016 lb/MMBtu. This estimate includes a SCR and CO catalyst to control NO_x and CO emissions downstream of the combustion turbines.

The raw syngas produced by the gasification process requires cleaning to remove particulate, ammonia (NH3), sulfur, and other contaminants prior to firing in the gas turbine. Acid gas cleanup processes used to clean the raw syngas are very effective as proven by the oil and gas industries which have operated for many years with over 99.8 percent sulfur recovery. The SELEXOL process will be used to achieve the specified SO_2 emission limits. Removal of pollutants from the syngas stream results in lower emissions than from a conventional plant utilizing the same fuels.

In addition to the main stack emissions from the heat recovery steam generators, the facility may incorporate a thermal oxidizer intended to burn the tail gas coming off of the tail gas treatment unit. This thermal oxidizer will be operated continually during startup and normal operations. It is possible to recycle the tail gas back to the SRU, but a small portion of this gas, vents and other startup streams, will still need to be incinerated in the thermal oxidizer. The use and size of the thermal oxidizer will vary from project to project.

The IGCC facility will also contain a flare. The flare is used during unit startup and emergency shutdown conditions. During startup, all of the syngas produced is flared until the appropriate syngas quality is achieved to allow the syngas to be run to the gas turbine. Should either or both of the gas turbines trip, the syngas will be routed to the flare until the gasifiers can be safely shut down. The flare has continually operating pilots operating on natural gas.

It is possible to achieve a 90 percent reduction in CO_2 emissions. However, the more CO_2 removal required, the higher the capital and operating costs and the higher the performance derate. For this assessment, it was assumed that IGCC CO_2 emissions are controlled to 1,100 lb/MWh in the SELEXOL unit. Due to the de-rating of the plant after the SELEXOL CO_2 capture process is installed, all other uncontrolled emissions in lb/MW-hr of net generation are expected to increase.

5.3.6 IGCC CCGT Water and Waste Disposal

Waste resulting from the IGCC power production process includes gasifier ash which may be sold as aggregate given the existence of a market for its consumption. This assessment assumes disposal of ash in an onsite ash landfill. Sulfur byproduct in the form of elemental sulfur is typically transported offsite and can be sold given the existence of a market for its consumption. Costs associated with the disposal of sulfur have been treated as a net-zero process and have been excluded from the estimate. A detailed site specific study would be required to determine waste product market availability. Process waste water resulting from plant operation is assumed to be delivered to site boundary and treatment costs have been excluded from the estimate.

Estimated water consumption for a 2x1 IGCC facility with and without carbon capture is 4,600 gpm and 3,870 gpm, respectively.

5.3.7 IGCC Capital Cost Estimate

The project costs for the IGCC options included in this assessment are shown in Table 5.8 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. A CO_2 capture system installation on an IGCC facility includes a replacement of the hydrolysis reactor to accommodate the shift reaction, additions to the syngas cooling train,

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additions to the SELEXOL acid gas removal equipment to recover CO_2, HRSG modifications, modifications to the gas turbines to burn the hydrogen rich gas, and the addition of a CO_2 compressor. Further detail can be found in Appendix A.

Table 5.8: IGCC Capital Cost Estimates

	2x1	
Carbon Capture Description	None	CC
Project Capital Cost (2013 MM$)	[redacted]	
Owner's Costs (2013 MM$)		
Total Project Costs (2013 MM$)		

5.3.8 IGCC O&M Cost Estimate

The estimated O&M expenses for the IGCC technology evaluated in this assessment are shown in Table 5.9. Additional detail can be found in Appendix A. Major maintenance costs include costs for work typically conducted during plant outages. These costs include steam turbine overhauls, major boiler replacements, fabric filter bag replacements, SCR catalyst replacements and water treatment system replacements. Due to the increased size and role of the AGR for the CO_2 capture case, an additional control room operator is required for each shift. Other O&M impacts are minimal, although the reduced output of the facility raises the costs on a $/kW-yr and $/MWh basis.

Table 5.9: IGCC O&M Cost Estimates

	2x1	
Carbon Capture Description	None	CC
Fixed O&M ($/kW-yr)	[redacted]	
Major Maintenance ($/MWh)		
Variable O&M ($/MWh)		

* * * * *

6 WASTE TO ENERGY TECHNOLOGIES

6.1 Stoker Firing

6.1.1 General Description

Stoker boiler technology is the most commonly used waste to energy (WTE) technology. Waste fuel is combusted directly in the same way fossil fuels are consumed in other combustion technologies. The heat resulting from the burning of waste fuel converts water to steam, which then drives a steam turbine generator for the production of electricity.

Stoker grate technology is most commonly used for waste combustion and represents the majority of commercial experience. Stoker grate boilers utilize a grate system in the lower section of the boiler that moves the fuel through the combustion zone. For waste combustion, vendors recommend a “recipro-grate” technology. This grate system alternates stationary and moving grates throughout the bed. Fuel enters the boiler through chutes and is distributed across the grate. Stoker boilers operate at the highest possible efficiency and lowest emissions when the fuel is spread evenly across the grate. As the moveable grates reciprocate, the fuel is pushed through the combustion chamber. Air is introduced into the boiler under the grate and via an over-fire air system. Due to the high gas velocities around the grate, stoker boilers can have high amounts of unburned fuel carried over and out of the furnace. Bottom ash is discharged from the finishing grate into a wet bottom ash hopper for transportation to ash load out.

Stoker boiler technology is well suited for combustion of the variety of fuel constituents found in residential and commercial waste. The lower section of the boiler is constructed to handle corrosive conditions and fuel variability as water walls are typically refractory lined and the stoker grating is constructed out of high quality alloy stainless steel. This assessment evaluates 50 MW WTE stoker fired facilities for three different fuel types including municipal solid waste, refuse derived fuel, and wood biomass in the form of chipped wood. Adequate fuel sources are assumed to be nearby and delivered to the facility; fuel processing costs have been excluded from this assessment.

Appendix B includes maps developed by the National Renewable Energy Laboratory (NREL) that show the availability of biomass resources in Kentucky. Tax incentives for renewable energy production exist through Kentucky's Incentives for Energy independence Act (IEIA), passed in 2007. Tax refunds and credits are available for renewable generation projects with a minimum capital investment of $1 million. Eligible projects include retrofits and new generation, and eligible technologies include biomass.

6.1.2 Stoker Boiler Waste-to-Energy Fuels

A variety of fuels are commonly utilized in WTE facilities, often as a last means of resource recovery and landfill management. These fuels often vary widely in consistency and content, not only by location, but also by load from within each location. Commonly incinerated fuels for energy recovery include municipal solid waste, refuse derived fuel, and wood biomass waste.

6.1.2.1 Municipal Solid Waste

Municipal solid waste (MSW) is comprised of residential and commercial discarded materials, including glass, paper, food residues, yard trimmings, textiles, plastics, and other similar materials. The content and consistency of MSW can vary greatly depending upon location. Household hazardous wastes, toxic chemicals, and bulky items larger than four feet in length are not normally part of MSW and are assumed to be excluded.

6.1.2.2 Refuse Derived Fuel

Refuse derived fuel (RDF) is MSW that has been further processed prior to use as fuel. This typically involves removal of recyclables and less combustible elements of the waste material, such as metals and glass. RDF is typically shredded and dehydrated after this removal, and sometimes even pelletized, depending on the requirements of the waste disposal technology. This assessment assumes minimal processing of MSW to remove non-combustibles.

6.1.2.3 Wood Biomass Waste

Wood biomass waste fuel is typically comprised of forest residues and yard waste associated with tree removal and wood processing, as well as waste resulting from construction. It typically includes leaves, branches, limbs, and processed woods such as plywood, building lumber, and sawdust. Wood waste is often further processed prior to use as fuel into wood chips, pellets, or sawdust.

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6.1.3 Stoker Boiler Performance

The following table provides performance estimates for the stoker fired WTE technology options. Performance is based on full load operation at average ambient conditions of 59°F and 60% RH at 600 feet of elevation when utilizing the indicated fuels as feedstock. Performance may vary significantly depending on actual waste constituency. Further performance detail can be found in Appendix A.

Table 6.1: WTE Stoker Performance Estimates

	MSW	RDF	Biomass
Base Load Net Output (kW)	50,000	50,000	50,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]		

6.1.4 Stoker Boiler Land Use Requirements

Estimated land usage/output requirement for the WTE stoker technologies evaluated in this assessment is 0.5 acre/MW.

6.1.5 Stoker Boiler Emissions Control

Emissions resulting from waste-to-energy facilities are highly fuel dependent. Modern waste and biomass fired stoker boiler facilities typically utilize an SNCR system for NO_x control, utilizing aqueous ammonia as the SNCR reagent to achieve reduction to 0.1 lb/MMBtu. Longer fuel residence time, characteristic of stoker boiler combustion, yields inherently low CO emissions of 0.15 lb/MMBtu, which are assumed to be uncontrolled.

SO_2 and mercury control for combustion of fuels with low sulfur content on a stoker unit is accomplished through the use of a dry-sorbent injection system. Anticipated emissions levels are within expected permit requirements at 0.03 lb/MMBtu of SO_2 and 0.8 lb/TBtu of mercury.

A fabric filter baghouse is used to remove particulate matter prior to flue gas exit via the stack, resulting in PM/PM10 emissions of 0.01 lb/MMBtu. This assessment assumes the use of the emissions controls described above. Additional detail can be found in Appendix A.

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6.1.6 Stoker Boiler Water and Waste Disposal

With the installation of a dry sorbent injection system, the process byproducts are bottom ash and fly ash. In most cases, the byproducts of combustion are disposed in a landfill. For the purpose of this analysis, an on-site landfill has been included.

Water consumption for the evaluated technologies is estimated at approximately 500 gpm. Water is assumed to be sourced from the Ohio River. Intake structure costs are listed as an Owner's cost in Appendix A. Costs associated with the transport of water from the source to plant equipment are excluded from this assessment. This assessment also excludes costs associated with or delivery to a wastewater treatment facility provided by others.

6.1.7 Stoker Boiler Capital Cost Estimate

The project costs for the stoker fired WTE options included in this assessment are shown in Table 6.2 below. Capital costs exclude interest during fuel processing, construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

Table 6.2: WTE Stoker Capital Cost Estimates

	MSW	RDF	Biomass
Project Capital Cost (2013 MM$)	[redacted]		
Owner's Costs (2013 MM$)			
Total Project Costs (2013 MM$)			

6.1.8 Stoker Boiler O&M Cost Estimate

The estimated O&M expenses for the stoker fired waste to energy technologies evaluated in this assessment are shown in Table 6.3. Additional detail can be found in Appendix A. Major maintenance costs include costs for work typically conducted during plant outages. These costs include steam turbine overhauls, major boiler replacements, fabric filter bag replacements, SCR catalyst replacements and water treatment system replacements. Scheduled outages for stoker fired technology assume a 2 week outage each year for the boiler. Additionally, the entire

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facility will undergo an outage of approximately 6 weeks every 5 years, during which time, the steam turbine major maintenance will be performed.

Table 6.3: WTE Stoker O&M Cost Estimates

	MSW	RDF	Biomass
Fixed O&M ($/kW-yr)	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]

6.2 Co-firing Coal and Biomass Options

6.2.1 General Description

As emission controls and renewable energy requirements become more stringent, co-firing strategies are gaining popularity. Direct co-firing means that two fuels, usually coal and biomass, are burned simultaneously in the same combustion chamber, combining the high energy content of coal combustion and the lower emissions rates of biomass combustion. Other waste fuels may also be used for co-firing applications, including tire derived fuel (TDF). TDF is processed from shredded scrap tires and typically has greater heat content than most coals (Btu/lb). TDF also has lower sulfur emissions and less ash than most coals, but the emissions characteristics of biomass are more beneficial than TDF. Since the biomass fuel is a renewable energy source, co-firing helps power suppliers meet renewable portfolio standards, especially if used in baseload applications. Co-firing can be achieved with traditional coal boiler technologies using new equipment or retrofits of existing units.

Biomass co-firing has been successfully implemented or tested for a full range of boilers, but the practice is still maturing, and additional detailed studies are recommended before selecting equipment and fuel mix. This assessment evaluates two options: a new CFB boiler using a 50% fuel blend and a PC boiler retrofit using 10% biomass. Note that the percentage of biomass, commonly known as the "level" of co-firing, is based on the biomass fraction of the total heat content in the boiler (as opposed to the fraction of the fuel mass or volume).

Appendix B includes maps developed by the National Renewable Energy Laboratory (NREL) that show the availability of biomass resources in Kentucky.

6.2.1.1 Circulating Fluidized Bed

The combustion of biomass within a CFB boiler varies little from the process utilized for the traditional combustion of fossil fuels. Combustion still occurs in a suspended or fluidized bed of solid particles created by the introduction of air flow from the bottom of the boiler. As combustion takes place, smaller particles are carried out of the boiler and recirculated back into the bottom of the furnace to help ignite the new fuel being fed into the unit.

CFB boilers are more expensive than BFB and stoker technologies because of the recirculation equipment, but they exhibit slightly better performance and lower CO emissions than BFB units. CFB boilers also allow for greater fuel flexibility than BFB and stoker boilers.

This study evaluates a CFB boiler burning 50% wood-waste biomass (assumed to be in chipped form and of moderate moisture content) and 50% Illinois bituminous coal. It is important to note that the boiler would be capable of burning any blend of the two fuels, up to 100% of either, but performance and emissions characteristics would change accordingly. Co-firing with CFB was evaluated for this screening level assessment, but the actual selection among CFB, BFB, and stoker technologies would require an additional, more detailed study with consideration for permitting, fuel flexibility, fuel logistics, and economics.

6.2.1.2 PC Boiler Conversion

Co-firing is often achieved by modifying existing plants to accept two fuels, and the modifications vary in scope and complexity depending upon the expected fuel selection, fuel mixture, and the existing boiler technology. For PC conversions, the largest capital cost driver is based on whether the biomass fuel is blended with the coal or fed into the boiler separately. Assuming wood biomass is the co-fired fuel, additional equipment may be required to ensure that the fuel particles are no greater than ¼” with proper moisture content.

Co-firing levels of 2% and 10% are common in PC boilers. At low co-firing levels (up to ~2%), the fuels can be blended and fed into the pulverizers together. The conversion expenditures

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would be based on receiving, storing, and handling biomass fuel. However, as the co-firing level increases, the effectiveness of the pulverizing and boiler fuel feed equipment is hampered. To achieve higher co-firing levels (~10%), the biomass fuel must be fed into the boiler separately, which requires additional injection, handling, and feeding systems. Achieving higher levels requires more upfront capital, but the impact on emissions is more significant.

This evaluation assumes that an existing 100 MW PC plant with a tangentially-fired boiler will be converted to co-fire 90% Illinoi basin coal and 10% wood biomass. It is assumed that the biomass feedstock particle size will be less than ¼" and the moisture content less than 25%.

6.2.2 Co-firing Performance

The following table provides estimated performance for the CFB and PC co-firing technology options evaluated in this assessment. Performance estimates are based on full load operation at average ambient conditions of 59°F and 60% RH at 600 feet of elevation when utilizing the indicated fuels as feedstock. PC conversion performance is based on the effects that 10% co-firing would have a typical PC boiler. In similar field tested/implemented applications, boiler efficiencies were reduced about 1% for every 10% of co-firing. Further performance detail can be found in Appendix A.

Table 6.4: WTE FB Performance Estimates

	Co-fired CFB 50% Coal 50% Biomass	Co-Fired PC Retrofit 10% Biomass
Waste Fuel Description	Wood	Wood
Co-Firing % (Waste/Coal)	50 / 50	10 / 90
Base Load Net Output (kW)	50,000	100,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]	

6.2.3 Co-firing Land Use Requirements

Estimated land usage/output requirement for the fluidized bed technologies evaluated in this assessment is 0.7 acre/MW, which is comparable to fossil fuel fired fluidized bed facilities. The PC conversion assumes the same land use as the existing plant. It is assumed that biomass fuel storage can displace a portion of coal storage, and that the equipment modifications and/or additions will have negligible impacts on overall PC land use.

6.2.4 Co-firing Emission Controls

A biomass co-fired plant will have inherently lower emissions than a 100% coal plant of similar size because biomass fuels are essentially sulfur free and carbon neutral (biomass accounts for zero net carbon emissions in a sustainable life cycle). However, this evaluation assumes that certain emissions controls are still necessary to achieve permitting constraints. Expected emission control technologies are described below. Anticipated emissions levels for each technology and additional detail can be found in Appendix A.

6.2.4.1 CFB Emission Controls

It is assumed that emission targets will be similar to a 100% coal CFB unit, though the 50/50 co-fired CFB will have inherently lower SO_2, NO_x, mercury, and carbon emissions. Further SO_2 control is achieved with limestone injection in the furnace and an FGD system. While a standard coal CFB plant would likely control NO_x emissions with an SCR system, the biomass exhaust particulates may interfere with the catalyst. Therefore, an SNCR is assumed to reduce NO_x emissions in a co-fired CFB. Mercury is reduced with a sorbent injection system and particulate matter is collected in a baghouse. CO and CO_2 emissions are assumed to be uncontrolled.

6.2.4.2 PC Conversion Emission Controls

For a typical PC boiler burning coal only, NO_x emissions are controlled with low NO_x burners and an SCR system. Co-firing with biomass will inherently reduce NO_x emissions because most woody biomass has less nitrogen than coal, but post combustion controls would still be necessary. Because biomass exhaust can deactivate an SCR catalyst, an SNCR system is assumed in this evaluation.

Co-firing with 10% wood biomass is expected to reduce SO_2 emissions by ~10% compared to firing coal only, and additional SO_2 control is accomplished through the use of a wet flue gas desulfurization (FGD) system. A wet FGD system can achieve up to 98 percent SO_2 removal.

This evaluation also includes a baghouse to remove particulate from the flue gas and a sorbent injection system to control acid gases.

Test information indicates that the inherent mercury control provided by a fabric filter followed by a wet limestone scrubber is adequate to achieve 90 percent removal. At this time it is uncertain whether or not equipment manufacturers are willing to provide commercial guarantees to this level of mercury control. Therefore, the capital cost for a contingent carbon injection system has been included.

6.2.5 Co-firing Water and Waste Disposal

6.2.5.1 CFB Water and Waste Disposal

With the installation of a dry polishing FGD system, the process byproducts are bottom ash and fly ash. The fly ash can be utilized in the manufacturing of concrete should a market exist within the area, though high levels of mercury within the fly ash may negate marketability. In most cases, the byproducts are disposed in a landfill. For the purpose of this analysis, it was assumed a market would not be developed and an on-site landfill has been included.

Water consumption for the evaluated technologies is estimated at approximately 500 gpm. Water is assumed to be sourced from the Ohio River. Intake structure costs are listed as an Owner's cost in Appendix A. Costs associated with the transport of water from the source to plant equipment are excluded from this assessment. This assessment also excludes costs associated with or delivery to a wastewater treatment facility to be provided by others.

6.2.5.2 PC Conversion Water and Waste Disposal

Co-firing 10% biomass in a PC boiler is not expected to increase water consumption. A small amount of service water may potentially be required for biomass unloading and storage handling areas.

6.2.6 Co-firing Capital Cost Estimate

The project costs for the co-firing options included in this assessment are shown in Table 6.5 below. Capital costs exclude fuel processing, interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A. For co-firing retrofits,

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it is common to show the retrofit cost in terms of $/kW converted. For example, the [redacted] million cost below is shown as [redacted] per kW biomass, rather than [redacted] per kW for the entire output.

Table 6.5: WTE CFB Capital Cost Estimates

	Co-fired CFB 50% Coal 50% Biomass	Co-Fired PC Retrofit 10% Biomass
Waste Fuel Description	Wood	Wood
Project Capital Costs (2013 MM$)	[redacted]	
Owner's Costs (2013 MM$)		
Total Project Costs (2013 MM$)		

6.2.7 Co-firing O&M Cost Estimate

The estimated O&M expenses for the co-firing technologies evaluated in this assessment are shown in Table 6.6. Additional detail can be found in Appendix A. Major maintenance costs include costs for work typically conducted during plant outages. These costs include steam turbine overhauls, major boiler replacements, fabric filter bag replacements, and water treatment system replacements. Scheduled outages for CFB and PC technologies assume a two week outage each year for the boilers. Additionally, the entire facility will undergo an outage of approximately 6 weeks every 5 years, during which time, steam turbine major maintenance will be performed.

Table 6.6: WTE CFB O&M Cost Estimates

	Co-fired CFB 50% Coal 50% Biomass	Co-Fired PC Retrofit 10% Biomass
Waste Fuel Description	Wood	Wood
Fixed O&M ($/kW-yr)	[redacted]	
Variable O&M ($/MWh)		

6.3 WTE Reciprocating Engine

6.3.1 General Description

In the United States, 85% of waste gas fired energy projects utilize proven reciprocating engine technology. In this assessment, two WTE options are evaluated: landfill gas and anaerobic digestion.

6.3.1.1 Landfill Gas

"Land-filling" is the primary method for disposal of municipal and solid waste in the United States. Landfill waste produces significant amounts of landfill gas (LFG) that can be an explosion hazard. Therefore, a beneficial solution is to collect the LFG and use it to produce electricity. LFG is generated by the natural degradation of municipal solid waste by anaerobic microorganisms. The gas can be collected by drilling a series of wells into the landfill and connecting them by a piping system. The gas entering the gas collection system is saturated with water, which must be removed prior to further processing. The typical dry composition of the low-Btu gas is 57 percent methane, 42 percent carbon dioxide, 0.5 percent nitrogen, 0.2 percent hydrogen and 0.2 percent oxygen. After the water is removed, the LFG can be used directly in reciprocating engines or be further processed into a fuel with a higher heating value for use in gas turbines, boilers, or fuel cells.

6.3.1.2 Anaerobic Digestion

Anaerobic digestion is a series of processes that result in the bacterial breakdown of organic matter given the absence of oxygen. The products of these processes include digested solids that can be utilized in compost, fertilizer, and other such applications, and low-Btu biogas that holds approximately 60% of the heat content found in pipeline quality natural gas. Anaerobic digestion is a batch type process requiring approximately 20 days of residence time, depending on the temperature range under which the process is allowed to occur. Longer residence time can yield higher quality biogas. Within the United States, sewage sludge digestion systems are typically composed of multiple, staggered complete mix digesters which are fed by a municipal waste processing facility. The resultant biogas can be utilized in a combustion engine for the generation of power and/or heat, a portion of which is typically used to maintain digester temperature. Anaerobic digestion of wastewater typically starts to become economically feasible when

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processed flow is greater than 3 million gallons per day (MGD). The Point Loma waste treatment facility in San Diego processes approximately 240 MGD of wastewater which is used to produce biogas utilized on-site for heat and power generation. A 5 MW system is estimated to require approximately 150 MGD of wastewater processing to supply the required amount of biogas.

6.3.2 Waste Gas Engine Performance

The following table provides estimated performance for the waste gas options evaluated in this analysis. Performance is based on full load operation at average ambient conditions of 59°F and 60% RH at 600 feet of elevation. Further performance detail can be found in Appendix A.

Table 6.7: Waste Gas Engine Performance Estimates

	LFG	AD Biogas
Base Load Net Output (kW)	5,000	5,000
Base Load Net Heat Rate (HHV Btu/kWh)	[redacted]	

6.3.3 Waste Gas Engine Land Use Requirements

Estimated land usage/output requirements for the WTE reciprocating engine technologies evaluated in this assessment are 0.03 acre/MW and 0.33 acre/MW for LFG combustion and an anaerobic digestion facility, respectively. Note that this estimate assumes the use of an existing landfill of at least 200 acres or the availability of an adequate wastewater supply.

6.3.4 Waste Gas Engine Emissions Control

LFG and biogas emissions levels can vary considerably depending on feedstock constituency. Direct firing of waste gas in a reciprocating engine does not typically require additional gas scrubbing equipment that would be needed if firing in a combustion turbine or selling as pipeline grade. This assessment assumes an SCR and CO catalyst is required for reciprocating engine operation when combusting waste gas which results in the reduction of emissions to levels comparable to natural gas combustion. Operation with an SCR yields reduction of NO_x emissions to 5 ppmvd at 15 percent excess O_2 while CO catalyst results in anticipated emissions of 0.05 lb/MMBtu of heat input.

For simple cycle units operating on LFG or biogas, uncontrolled CO_2 emissions are estimated to be 180 lb/MMBtu. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Emissions for sulfur dioxide are estimated to be less than 0.01 lb/MMBtu (HHV) for the evaluated technology. Additional detail can be found in Appendix A.

6.3.5 Waste Gas Engine Waste Disposal

The condensate removed from the LFG will contain concentrations of volatile organics (benzene, toluene, vinyl chloride and others) that likely cannot be discharged to a publicly operated treatment works without pretreatment. The quality of the gas at each landfill varies considerably, so an analysis of the gas must first be performed to verify that gas cleanup equipment will be needed. This assessment assumes LFG condensate will be discharged back to the existing landfill.

The quality of the digested solids resulting from the anaerobic digestion process varies depending on waste composition, digestion process temperature range, and residence time allowed. Further treatment of resulting biosolids may be required to be in compliance with mandates issued by the Environmental Protection Agency depending on the end use applications. This assessment assumes that no additional treatment is required and treatment costs are excluded. A market may exist for the sale of digested biosolids, which would require a detailed site specific study for analysis. No recovery costs associated with the sale of biosolids have been included in this assessment.

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6.3.6 Waste Gas Engine Capital Cost Estimate

The project costs for the waste gas reciprocating engine options included in this assessment are shown in Table 6.8 below. Capital costs exclude interest during construction, financing fees, off-site infrastructure, and transmission upgrades. Section 3 of this evaluation provides the assumptions used to develop this estimate. Further detail can be found in Appendix A.

Table 6.8: WTE Engine Capital Cost Estimates

	LFG	AD Biogas
Project Capital Cost (2013 MM$)	[redacted]	
Owner's Costs (2013 MM$)		
Total Project Costs (2013 MM$)		

6.3.7 Waste Gas Engine O&M Cost Estimate

O&M costs for the waste gas reciprocating engine options included in this assessment are shown in Table 6.9 below. Major maintenance costs are included in the variable O&M costs. Further detail can be found in Appendix A.

Table 6.9: WTE Engine O&M Cost Estimates

	LFG	AD Biogas
Fixed O&M ($/kW-yr)	[redacted]	
Variable O&M ($/MWh)		

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7 RENEWABLE TECHNOLOGIES

7.1 Wind Energy

7.1.1 General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, and are typically used to pump water or generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW operate are horizontal-axis. Subsystems for either configuration typically include a blade or rotor to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. A 10 kW turbine typically has a rotor diameter of over 20 feet, while a 1.5 MW turbine has a rotor diameter of approximately 230 feet. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. Kentucky has average wind speeds that are less than 12.5 mph and each county is considered a Class 1 wind area. According to NREL, Class 3 wind areas (wind speeds of 14.5 mph) are generally considered to have suitable wind resources for wind generation development. Wind resource maps are included for the state of Kentucky in Appendix B.

7.1.2 Wind Turbine Performance

The net plant output of the evaluated wind energy facility is 50 MW with a 27% capacity factor. Ideally, utility-scale wind generation sites should have at least 30% capacity factor at 80 meters

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above ground. Per NREL data, Kentucky has the potential to produce about 60 MW at 30% capacity factor or higher, which is the 6th lowest potential in the country.

7.1.3 Wind Turbine Land Use Requirements

Each wind turbine directly impacts about one acre of land after installation. Access roads impact additional land, but most of the area between turbines can still be used for farming or grazing. The total area required for wind farms varies widely, but NREL data suggests that 85 acres/MW is average in the U.S.

7.1.4 Wind Turbine Emissions Control

No emissions control equipment is required for the wind energy facility.

7.1.5 Wind Turbine Water and Waste Disposal

No water or waste disposal is required for a wind energy facility.

7.1.6 Wind Turbine Capital Cost Estimate

The estimated capital cost of a 50 MW wind energy facility is [redacted]/kW. Capital cost excludes Owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

7.1.7 Wind Turbine O&M Cost Estimate

The estimated fixed O&M cost is expected to be [redacted]/kW-yr for the wind energy facility. This includes variable O&M (minimal) and major maintenance costs.

7.2 Solar Energy

7.2.1 General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into Solar Photovoltaic (PV) technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell, and Solar Thermal technology, which converts the radiant heat of the solar energy to electricity through an intermediary fluid.

7.2.2 Photovoltaic Cells

Photovoltaic (PV) cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of 0.5% per year. At the end of a typical 30 period, the conversion efficiency of the cell will still be greater than 80% of its initial efficiency. This assessment assumes the use of polysilicon PV cells, but screening level costs are also reflective of thin film technologies.

7.2.3 Solar Thermal

Solar Thermal technology transfers solar energy to an intermediary liquid (typically mineral oil or molten sodium and potassium nitrate salts) in the form of heat, which is then used to boil water and produce steam. That steam is sent to a Steam Turbine Generator (STG) for the production of electricity. The life expectancy of a solar thermal power plant is similar to that of any fossil fueled thermal plant as long as preventative and routing maintenance programs are undertaken.

Solar thermal power plants tend to require more land than an equivalently sized PV project due to the need for additional features to handle steam cycle operation, such as blow down ponds to handle the cooling water. Solar thermal projects can also require additional land if thermal energy storage is included as the solar field would need to be enlarged to generate the extra energy to be stored.

There are currently several Solar Thermal designs for power generation at various stages of development including:

7.2.3.1 Solar Parabolic Trough

A solar parabolic trough design consists of mirrors which concentrate solar energy to a piping system through which the intermediary liquid is pumped in a closed loop. The heated liquid passes through a heat exchanger, which results in the production of steam that is then sent to a steam turbine generator. Some of the oldest operating solar thermal power plants in the country use this technology, including 350 MW built in the late 1980's in California. In 2005, the Solar-One 64 MW parabolic trough plant was built in Nevada and currently, the Abengoa 280 MW plant is in the final construction stages in Arizona.

This technology requires the control of three loops of fluids. The first loop contains mineral oil that is pumped through the solar field to be heated via concentrated solar energy prior to its flow through a heat exchanger and before being pumped around the solar field again in a closed loop. The steam cycle loop contains water that is boiled in the heat exchanger, producing steam which powers the turbine generator before being condensed back to water in another closed loop. The cooling water loop contains the water used to cool the condenser, utilized within a heat rejection system.

The maximum temperature of mineral oil is limited to about 750°F to prevent the oil from breaking down. This limits the temperature of the steam and consequently the Carnot efficiency of the steam power cycle. Research is continuing in the search for a higher temperature solar loop fluid that allows for increased efficiency.

7.2.3.2 Solar Power Tower

A solar power tower consists of mirrors which concentrate solar energy to a boiler/receiver at the top of a large tower through which an intermediary liquid is pumped in a closed loop. The heated liquid passes through a heat exchanger to produce steam, which is then sent to a steam turbine. In some designs, salts are used as the intermediary fluid such that the heated medium can be stored in a tank and drawn as necessary (thermal storage). In some designs, a mixture of sodium and potassium nitrate salts are used as the intermediary fluid. At temperatures above 500 °F this molten salt mixture has an appearance and viscosity similar to water. The hot salt, typically at 1,050 °F can be stored in an insulated tank and drawn as necessary to heat water and produce steam (thermal storage). This gives the power tower technology an advantage over the parabolic trough as the steam cycle Carnot efficiency is higher due to the higher steam temperature.

Until recently, no power towers had been built in the United States since the 10 MW demonstration tower at Barstow, California in the late 1990's. Currently there are three projects under development or construction including the NRG Ivanpah (392 MW), SolarReserve Rice (150 MW), and Crescent Dunes (110 MW) projects.

7.2.3.3 Solar Dish

A solar dish consists of a large, parabolic dish that concentrates solar energy and directs it to a Stirling reciprocating-type engine. In the engine, pistons are driven by the expansion and compression of a gas when cyclically heated and cooled to produce power. Stirling Energy Systems was the last company in the United States to (unsuccessfully) try to commercialize the dish technology. There are currently no systems in operation greater than 5 kW in capacity.

7.2.3.4 Solar Chimney

A solar chimney consists of a large greenhouse, on the order of 400 feet in diameter and 8 to 10 feet tall, which traps radiant heat. At the center of the greenhouse is a tall chimney, on the order of 2,500 feet in height, with wind turbines located at its base. Natural draft convection forces the heated air into and up through the chimney at speeds of up to 40 mph, spinning the wind turbines to generate electricity. Australian based Enviromission is currently attempting to permit a 100 MW Solar Chimney facility in Arizona.

7.2.4 Solar Energy Performance

According to NREL, Kentucky receives between 4.0-5.5 kWh/m^2/Day of sunlight, as shown in Appendix B. Areas in the western United States with high rates of solar development receive over 7.5 kWh/m^2/Day. This evaluation assumes flat plate photovoltaic cells and solar power tower designs as proven, commercially available technologies in operation.

The net plant output of the PV and solar power tower technologies is assumed to be 50 MW with a 19% capacity factor.

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7.2.5 Solar Energy Land Requirements

The area of land required for a fixed, ground mount PV array is estimated at 5 acres/MW. Single axis tracking arrays require 6 - 8 acres/MW. Concentrating solar technologies, including power towers, often require more land area than PV (up to 10 acre/MW). For all solar technologies, this footprint represents land that will be otherwise unusable. Access roads and support facilities are not included in these estimates.

7.2.6 Solar Energy Emissions Control

No emissions control equipment is required for a solar energy conversion facility.

7.2.7 Solar Energy Water and Waste Disposal

No waste disposal is required for a PV energy conversion facility. If wet cooling is used in a power tower conversion facility, cooling tower blow down water will need to be handled at an estimated 2,500 gpm. Compared to conventional fossil plants, water consumption through evaporation is considerably higher due to lower operating temperatures, which contributes to lower steam cycle and overall system efficiency.

7.2.8 Solar Energy Cost Estimate

The estimated capital cost of the 50 MW solar facility options evaluated in this assessment are shown in Table 7.1 below. This assessment assumes the use of polysilicon PV cells, but screening level costs are also reflective of thin film technologies. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

Table 7.1: Solar Energy Capital Cost Estimates

	PV	Power Tower
Project Capital Cost (2013 MM$)	[redacted]	
Owner's Costs (2013 MM$)		
Total Project Costs (2013 MM$)		

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7.2.9 Solar Energy O&M Cost Estimate

The estimated O&M costs are expected to be [redacted]/kW-yr for the solar photovoltaic plant and [redacted]/kW-yr for the solar thermal plant. This includes fixed and variable O&M (minimal) and major maintenance costs.

7.3 Hydroelectric

7.3.1 General Description

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. Specially designed low-head hydro turbines are often current driven and therefore operate at low speeds of 100 to 500 rpm in various configurations and orientations. Generators can be directly coupled to the turbine or gear-box driven, and typically range in output from 50 kW to 15 MW depending on available pressure and flow rates.

Since they do not require a large head loss, low-head hydroelectric facilities can be incorporated in a variety of different applications, including rivers, canals, aqueducts, pipelines, and irrigation ditches. This allows the technology to be implemented much more easily than conventional hydropower, and with a much smaller impact to wildlife and environmental surroundings. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions such as dense vegetation or algae growth, sediment levels, and drought. Additionally, low-head hydropower is relatively new and undeveloped, resulting in a high capital cost for the relatively small generation output.

This evaluation assumes an advanced hydroelectric generation facility design of either the Kaplan or Bulb type installations. The Kaplan turbine is a propeller type, vertical axis machine in which water enters radially and exits the turbine axially. The propeller is immersed in the water flow, but is coupled to an electric generator above the turbine blades, outside of the water. Kaplan turbine designs typically include adjustable vanes and inlet gates to accommodate variable flow. The Bulb type turbine design is similarly a propeller driven machine, but with a vertical axis in which water both enters and exits the turbine axially. Additionally, the coupled generator is encased in a bulb shaped casing which is itself immersed in the water. Two wires

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protrude from casing and are connected to the electric distribution system above ground. There are multiple configurations for both types of turbines. If hydroelectric generation technology is chosen for further development, a more detailed study shall be performed to evaluate other hydroelectric technology and configuration designs.

7.3.2 Hydroelectric Performance

The net plant output of the hydroelectric generation facility assumed for this assessment is 50 MW.

7.3.3 Hydroelectric Land Use Requirements

Land use requirements for how-head hydroelectric facilities are entirely dependent on geographical constraints. Parameters such as river width, depth, flow, and elevation change can affect the potential capacity and performance of the facility. A site specific study is required to determine land use requirements for this technology.

7.3.4 Hydroelectric Emissions Control

No emissions control equipment is required for a hydroelectric generation facility.

7.3.5 Hydroelectric Water and Waste Disposal

No water or waste disposal is required for a hydroelectric generation facility.

7.3.6 Hydroelectric Capital Cost Estimate

The estimated capital cost of a 50 MW hydroelectric generation facility is [redacted]/kW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

7.3.7 Hydroelectric O&M Cost Estimate

The estimated fixed O&M cost is expected to be [redacted]/kW-yr for the hydroelectric generation facility. This includes variable O&M (minimal) and major maintenance costs.

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8 ENERGY STORAGE TECHNOLOGIES

8.1 Pumped Hydroelectric Energy Storage

8.1.1 General Description

A pumped hydroelectric plant (or "pumped hydro") is strictly a peaking energy storage power generating facility. The plant includes a lower reservoir that often already exists, a powerhouse, an upper reservoir that is usually constructed for the purpose, and a means for conveying water between the upper and lower reservoirs. The powerhouse includes turbine generators that can be reversed into motor-driven pumps, balance of plant equipment and various control systems.

During off peak periods, when a surplus of lower cost electrical energy exists, the plant is operated in the pump mode, pushing water from the lower reservoir to the upper reservoir. During peak periods, the water is released from the upper reservoir through the pump/turbines to generate electrical energy to meet the system peak demand. Therefore, pumped hydro is an energy storage method which stores the surplus lower cost electrical energy in the gravitational potential energy of the water for use and sale at a profit during peak electrical usage.

Pumped hydroelectric technology is among the most mature energy storage technologies available with 130 GW of storage in operation world-wide. Pumped hydroelectric facilities remain among the more expensive storage options, typically incurring extensive costs associated with civil construction of the upper reservoir and water runway as well as permitting efforts accompanying this construction. However, the anticipated life expectancy of these facilities is much higher relative to other technologies at 30 years, given routine maintenance. The Federal Energy Regulatory Commission has authorized over 20 pumped hydroelectric energy storage facilities in the United States that are currently in operation, totaling nearly 20 GW of storage capacity, with three times that capacity again in varying stages of the permitting process.

8.1.2 Pumped Hydro Storage Performance

The net plant output of the pumped hydroelectric storage facility assumed in this assessment is 200 MW with 80% storage efficiency.

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8.1.3 Pumped Hydro Storage Land Use Requirements

Land use requirements for pumped hydroelectric facilities are entirely dependent on geographical constraints. Parameters such as lower reservoir water source capacity, upper reservoir space constraints on basin size and depth, and elevation change between reservoirs can affect the potential capacity and performance of the facility. A site specific study is required to determine land use requirements for this technology.

8.1.4 Pumped Hydro Storage Emissions Control

No emissions control equipment is required for a pumped hydroelectric storage facility.

8.1.5 Pumped Hydro Storage Water and Waste Disposal

No water or waste disposal is required for a pumped hydroelectric storage facility.

8.1.6 Pumped Hydro Storage Capital Cost Estimate

The estimated capital cost of a 200 MW pumped hydroelectric storage facility is [redacted]/kW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

8.1.7 Pumped Hydro Storage O&M Cost Estimate

The estimated fixed O&M cost is expected to be [redacted]/kW-yr for the pumped hydroelectric storage. This includes variable O&M (minimal) and major maintenance costs.

8.2 Advanced Battery Energy Storage

8.2.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed "flow," "conventional," and "high temperature" battery designs. Each battery type has unique features yielding specific advantages compared to one another.

8.2.1.1 Flow batteries

Flow batteries are a more recent technological development that utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the redox reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

8.2.1.2 Conventional batteries

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell; the most popular conventional batteries are lead acid and lithium ion type batteries.

Lead acid batteries are the most mature and commercially available battery technology, with approximately 35 MW installed worldwide. This design has undergone considerable development since conceptualized in the late 1800's. However, though lead acid batteries require relatively lower capital cost, the technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements) and a short life cycle of between 5 and 10 years.

Lithium ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium ion technology has seen a resurgence of development interest due to its high energy density, low self-discharge, and cycling tolerance, but remains mostly developmental for utility generation applications. Life cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion), and can range from 2,000-3,000 cycles at high discharge rates up to 7,000 cycles at very low discharge rates. Though continued development is anticipated to reduce production costs, uncertainty of these developments lends to wide ranges in project costs.

8.2.1.3 High Temperature batteries

High temperature batteries operate similarly to conventional batteries, but utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level, the most popular and technically mature of which is the Sodium Sulfur (NaS) battery.

The Sodium Sulfur (NaS) battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium.

The melting points of sodium and sulfur are approximately 98C and 113C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300C, which results in a higher self-discharge rate of 14-18%. These systems are expected to have an operable life of around 15 years and are currently one of the most developed chemical energy storage systems. Japan-based NGK insulators, the largest NaS battery manufacturer, recently installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project’s inception in the 1980’s. Commercial development in utility level applications continues to progress, the costs of which have remained relatively stable in recent years compared to other technologies.

Due to technical maturity level, advanced nature, and commercial stability, this evaluation assumes NaS batteries as the representative technology.

8.2.2 Battery Storage Performance

The net plant output of the evaluated advanced NaS battery storage facility is 10 MW with 85% storage efficiency.

8.2.3 Battery Storage Land Use Requirements

The estimated land use requirement of the evaluated NaS battery storage facility is approximately 0.03 acre/MW.

8.2.4 Battery Storage Emissions Control

No emissions control equipment is required for an advanced battery storage facility.

8.2.5 Battery Storage Water and Waste Disposal

No water or waste disposal is required for an advanced battery storage facility.

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8.2.6 Battery Storage Capital Cost Estimate

The estimated capital cost of a 10 MW advanced NaS battery storage facility is [redacted]/kW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

8.2.7 Battery Storage O&M Cost Estimate

The estimated fixed O&M cost is expected to be [redacted]/kW-yr for an advanced battery storage facility. This includes variable O&M (minimal) and major maintenance costs.

8.3 Compressed Air Energy Storage

8.3.1 General Description

Compressed air energy storage (CAES) offers a way of storing off-peak generation that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander.

This method of operation takes advantage of less expensive, off-peak power for generation during periods of higher demand. CAES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and CAES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to all consumers. Additionally, CAES has a direct benefit to wind resources as it is able to absorb excess wind energy that otherwise would need to be curtailed due to transmission constraints. This could increase the percentage of power generated by clean technologies and delivered during peak hours.

There have been two commercial CAES plants built and operated in the world. The first plant began commercial operations in 1978 and was installed near Huntorf, Germany. This 290 MW

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facility included major equipment by Brown, Boveri, and Company (BBC). The second is located near McIntosh, Alabama and is currently owned and operated by PowerSouth (originally by Alabama Electric Cooperative). This 110 MW facility began commercial operations in 1991 and employs DR equipment. BMcD served as the Owner's engineer for this project.

"Second generation" CAES designs have recently been developed, but do not have commercial operating experience. These conceptual designs incorporate a separate gas turbine for additional generation capacity and uses the exhaust energy as a source of preheat for the stored air before entering the expansion process. The compression-expansion portion of these designs is similar to "first generation" CAES designs. The designs differ in that a simple cycle gas turbine plant operates in parallel to the compression-expansion train and the exhaust is used in a recuperator instead of utilizing a combustor to preheat the stored air.

Based on technical maturity and commercial availability, "first generation" CAES is assumed as the representative technology in this assessment. One gas turbine and expander CAES train consumes approximately 105 MW for compression power for a full generation ability of 135 MW (based on 12 hours compression time and 8 hours generation time). CAES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that air can be compressed at a low cost and used to generate energy when costs are considerably higher. CAES typically does not provide a practical energy storage solution for areas without a high spread in peak and off-peak energy pricing.

8.3.2 CAES Performance

The net plant output of the evaluated CAES facility is 135 MW. The compressor train is assumed to supply approximately 420 lbs/second of compressed air at 1,200 psia to a cavern for storage. This process requires approximately 105 MW of compressor power to store air for full generation capacity of 135 MW (gross). The CAES facility heat rate at which the unit would be dispatched, which includes the fuel required for combustion and excludes compression energy, is assumed to be [redacted] Btu/kWh HHV. When the storage is charging, 105 MW of compression energy is required.

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Kentucky is known to have many karsts which are not favorable geology for CAES. Geological studies must be performed to determine if any deeper rock formations in the state are suitable for CAES.

8.3.3 CAES Land Use Requirements

The estimated land use requirement of the evaluated CAES facility is approximately 0.04 acre/MW for major equipment and an additional 0.08 to 1.2 acre/MW for balance of plant equipment and access roads.

8.3.4 CAES Emissions Control

An SCR system is utilized in the DR CAES design along with demineralized water injection in the combustor to achieve NO_x emissions of 2 ppmvd. A CO catalyst is also used to control CO emissions to 2 ppmvd at the exit of the stack.

The use of an SCR and a CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with the exhaust gas to strip out NO_x. This requires onsite ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this assessment.

8.3.5 CAES CCGT Water and Waste Disposal

Waste disposal for simple cycle options is negligible. Since the primary fuel to be burned is natural gas, no solid byproducts occur from combustion.

8.3.6 CAES Capital Cost Estimate

The estimated capital cost of a 135 MW CAES facility is [redacted]/kW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

8.3.7 CAES O&M Cost Estimate

The O&M estimates for a CAES facility are as follows: fixed O&M costs of [redacted]/kW-yr, major maintenance costs of [redacted]/MWh, and variable O&M costs of [redacted]/MWh.

* * * * *

9 NUCLEAR ENERGY TECHNOLOGIES

9.1 Small Modular Reactor (SMR)

9.1.1 General Description

Manufacturers have begun designing small modular reactors (SMRs) to create a smaller scale, completely modular nuclear reactor. These modular reactors are on the order of 30 feet in diameter and 90 meters in height. The conceptual technologies are similar to advanced pressurized water reactors (APWR) and the entire process and steam generation is contained in one, modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation.

According to these manufacturers, the benefit of these SMRs is two-fold; the smaller unit size will allow more resource generation flexibility and the modular design will reduce overall project costs while providing increased benefits in the areas of safety and concern, waste management, and the utilization of resources. Due to the design's modularity, most of the fabrication is planned to be done in the manufacturing facility before the vessel is shipped to the site. The goal is to reduce field labor and construction schedule.

This assessment includes the evaluation of a 225 MW SMR facility, representative of the Westinghouse SMR, which is based on the safety designs of the AP1000 reactor. Currently, SMRs are considered conceptual in design and are developmental in nature. Several manufacturers have completed conceptual design of these modular units to target lower output and overall costs of nuclear facilities and are in various stages of permitting applications with the Department of Energy. However, there is currently no industry experience with developing this technology outside of the conceptual phase. Therefore, the information provided in this assessment for the SMR option is based on feedback and initial indications from SMR manufacturers.

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9.1.2 SMR Performance

The estimated performance of a 225 MW SMR at average ambient conditions is a net plant output of 225 MW and a net plant heat rate of [redacted] Btu/kWh (HHV) yielding a net plant efficiency of 33.1% (HHV). This assessment assumes an 85% capacity factor.

9.1.3 SMR Land Use Requirements

Estimated land usage/output requirement for the SMR technology evaluated in this assessment is estimated at approximately 0.07 acre/MW or 2.91 ft^2/kW for a total of 15 acres.

9.1.4 SMR Emissions Control

No emissions control equipment is required for the nuclear option.

9.1.5 SMR CCGT Water and Waste Disposal

At the conclusion of an SMR operating cycle, the "spent" fuel is discharged and replaced with new fuel assemblies. Waste disposal permitting will need to be addressed.

9.1.6 SMR Capital Cost Estimate

The estimated capital cost of a 225 MW modular nuclear reactor is [redacted]/kW, based on the nominal average ambient net unit output of 225 MW. Capital cost excludes owner's costs, interest during construction, financing fees, off-site infrastructure, and transmission upgrades.

9.1.7 SMR O&M Cost Estimate

The O&M cost estimates for a SMR are fixed O&M costs of [redacted]kW-yr and variable O&M costs (excluding major maintenance) of [redacted]/MWh. O&M costs are based on the nominal average ambient unit output of 225 net MW. Major maintenance costs are included in the fixed O&M estimate.

* * * * *

10 CONCLUSIONS AND RECOMMENDATIONS

Among all the technologies evaluated, the SCGT has the lowest capital cost (per kW generated) and fastest startup time. CCGT has the next lowest capital cost per kW and offers the best heat rate. Both base configurations of SCGT and CCGT have the lowest emission rates among all the evaluated fossil fuel technologies.

Fuel cells are a possible option for small power generation needs with a high value on plant emissions. However, fuel cells are a relatively young technology with limited operating experience, and generally short life cycles.

PC boilers and CFB boilers are reliable and mature coal technologies with available emissions control options. Supercritical PC boilers have slightly better heat rates and emissions characteristics than subcritical units because they use less fuel, but the capital cost is slightly higher. Concern over emissions from coal plants is driving permitting challenges and technology developments. IGCC is a generation technology that burns synthetic natural gas made from coal, controlling emissions in the process. Carbon capture processes have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas, but not on the scale required for utility generation. LG&E/KU should continue to monitor the technical and financial feasibility of these technologies as they mature.

WTE generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. Because biomass fuels are considered carbon neutral and are essentially sulfur free, WTE generation can add renewable energy to the generation profile while reducing CO_2 and SO_2 emissions. Co-firing biomass and coal using traditional coal boiler technologies can be employed to capitalize on the high energy output of coal and reduced emissions of biomass.

Other renewable options include solar, wind, and hydro generation. PV capital costs have declined steadily, but this trend is expected to flatten, and costs remain higher than fossil generation technologies. However, PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals and reduce emissions. Wind and low-head hydroelectric energy generation constitute possible intermediate and base load generation resources. The wind power classifications across Kentucky are lower than the traditional threshold for effective utility-scale generation, but smaller, targeted opportunities may exist upon further study.

Energy storage technologies provide short term peaking generation and frequency management. Battery energy storage systems have fast response times, allowing flexibility in load management. Compressed air and pumped hydro energy storage systems store off-peak power to be released during on-peak demand periods. These systems can be costly, but may be necessary to provide short bursts of energy for load following or other system interruptions.

An emerging small modular nuclear technology offers a smaller footprint and standardized construction compared to traditional nuclear systems, which reduce overall project costs. This technology should be monitored for future technical and financial feasibility.

Information provided in this assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. BMcD recommends that LG&E/KU use this information to update production cost models for comparison of generation alternatives and their applicability to future resource plans. LG&E/KU should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

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Appendix A

Technology Assessment Summary Tables

LG&E TECHNOLOGY ASSESSMENT SUMMARY TABLE
NATURAL GAS - SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-1
November 2013 - Revision 0

PROJECT TYPE	**1xLM6000 SCGT**		**1xLMS100 SCGT**		**1xE-Class SCGT**		**1xF-Class SCGT**		**100 MW Recip Engine**		**1 MW Microturbine**		**10 MW Fuel Cell**	
BASE PLANT DESCRIPTION		Add-on		Add-on		Add-on		Add-on		Add-on		Add-on		Add-on
Number of Gas Turbines/Engines/Units	1	1	1	1	1	1	1	1	6	1	5	1	4	1
Representative Class Gas Turbine	GE LM6000		GE LMS100		GE 7EA		GE 7F-5		W 18V50DF		Capstone C1000	Capstone C200	FCE DFC3000	
Capacity Factor (%)	Peaking (25%)		Peaking (25%)		Peaking (25%)		Peaking (25%)		Peaking (25%)		Peaking (25%)		Baseload (85%)	
Startup Time (Cold Start)	-		-		-		-		6+ Hours (Note 2)		-		-	
Startup Time (Warm Start)	10 mins (Note 1)		10 mins (Note 1)		10 mins (Note 1)		35 mins (Note 3)		1-2 Hours (Note 2)		2.5 min (Note 1)	1 5 min (Note 1)	85 Hours (Note 4)	
Startup Time (Hot Start)	-		-		-		-		5 Minutes (Note 2)		-		-	
Maximum Ramp Rate (Online)	25%/min		33%/min		8%/min		9%/min		25%/min		40 %/min	65 %/min	0.2 %/min	
Forced Outage Factor (%)	3.50%		3.50%		3.50%		3.50%		1.80%		0.3%		0.9%	
Equivalent Forced Outage Rate (%)	34.49%		34.49%		34.49%		34.49%		27.40%		4.16%		13.78%	
Availability Factor (%)	91.45%		91.45%		91.45%		91.45%		91 80%		99.00%		95.00%	
Fuel Design	Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas	
Heat Rejection	Fin Fan Heat Exchanger		Wet Cooling Tower		Fin Fan Heat Exchanger		Fin Fan Heat Exchanger		Fin-Fan Heat Exch		Heat Recovery Module		N/A	
NO_x Control	Water Injection/SCR		Water Injection/SCR		DLN/SCR		DLN		SCR		Low Nox Combustion		N/A	
CO Control	Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Good Combustion Practice		Oxidation Catalyst		N/A		N/A	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		N/A		N/A	
Technology Rating	Mature		Mature		Mature		Mature		Mature		Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	3 Years		3 Years		3 Years		3 Years		3 Years		4 Months	4 Months	1.5 Year	1.5 Years
ESTIMATED PERFORMANCE														
Base Load Performance @ 20° F (Winter Average)														
Net Plant Output, kW	48,700	48,700	103,700	103,700	96,200	96,200	219,800	219,800	100,200	16,700	1,000	200	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Minimum Load Operational Status @ 20° F (Winter Average)														
Net Plant Output, kW	24,400	24,400	51,900	51,900	48,100	48,100	109,900	109,900	8,400	8,400	20	20	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Load Performance @ 59° F (Annual Average)														
Net Plant Output, kW	48,700	48,700	105,600	105,600	86,800	86,800	211,200	211,200	100,200	16,700	1,000	200	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Minimum Load Operational Status @ 59° F (Annual Average)														
Net Plant Output, kW	23,900	23,900	53,000	53,000	43,400	43,400	105,600	105,600	8,400	8,400	20	20	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Load Performance @ 90° F (Summer Average)														
Net Plant Output, kW	44,100	44,100	98,800	98,800	78,900	78,900	200,700	200,700	100,200	16,700	920	180	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Minimum Load Operational Status @ 90° F (Summer Average)														
Net Plant Output, kW	20,300	20,300	47,800	47,800	39,500	39,500	100,400	100,400	8,400	8,400	18	18	11,200	2,800
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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LG&E TECHNOLOGY ASSESSMENT SUMMARY TABLE
NATURAL GAS - SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-1
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PROJECT TYPE	1xLM6000 SCGT		1xLMS100 SCGT		1xE-Class SCGT		1xF-Class SCGT		100 MW Recip Engine		1 MW Microturbine		10 MW Fuel Cell	
BASE PLANT DESCRIPTION		Add-on		Add-on		Add-on		Add-on		Add-on		Add-on		Add-on
ESTIMATED CAPITAL AND O&M COSTS														
EPC Project Capital Costs, 2013 MM$ (w/o Owner's Costs)	[redacted]													
Owner's Costs, 2013 MM$														
Owner's Project Development														
Owner's Operational Personnel Prior to COD														
Owner's Engineer														
Owner's Project Management														
Owner's Legal Costs														
Owner's Start-up Engineering														
Operator Training														
Construction Power and Water														
Permitting and Licensing Fees														
Site Water Supply and Discharge														
Switchyard														
Political Concessions & Area Development Fees														
Startup/Testing (Fuel & Consumables)														
Site Security														
Operating Spare Parts														
Permanent Plant Equipment and Furnishings														
Builders Risk Insurance (0.45% of Construction Costs)														
Owner's Contingency (5% for Screening Purposes)														
Owner's Costs, 2013 MM$														
Total Project Costs, 2013 MM$														
Total Project Costs, 2013 $/kW														
Fixed O&M Cost, 2013$/kW-Yr														
Levelized Major Maintenance Cost, 2013$/GTG-hr														
Levelized Major Maintenance Cost, 2013$/GT-Start														
Variable O&M Cost, 2013$/MWh (excl. major maint.)														
Water Consumption, gpm	30	30	100	100	10	10	10	10	<10	<10	<10	<10	40	10
Start-up Fuel Consumption, MMBtu/Cold Start	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Start-up Fuel Consumption, MMBtu/Warm Start	40 (Note 1)	40 (Note 1)	90 (Note 1)	90 (Note 1)	90 (Note 1)	90 (Note 1)	200 (Note 1)	200 (Note 1)	80 (Note 1)	10 (Note 1)	0.5 (Note 1)	0.1 (Note 1)	1870 (Note 4)	470 (Note 4)
Start-up Fuel Consumption, MMBtu/Hot Start	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Start-up Power Generation, kWh/Cold Start	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Start-up Power Generation, kWh/Warm Start	2430 (Note 1)	2430 (Note 1)	5280 (Note 1)	5280 (Note 1)	4340 (Note 1)	4340 (Note 1)	10560 (Note 1)	10560 (Note 1)	5000 (Note 1)	1000 (Note 1)	40 (Note 1)	10 (Note 1)	29920 (Note 4)	7480 (Note 4)
Start-up Power Generation, kWh/Hot Start	--	--	--	--	--	--	--	--	--	--	--	--	--	--
DUAL FUEL CAPABILITY ADD-ON COST														
EPC Capital Cost, 2013 MM$ (w/o Owner's Costs)	[redacted]													
Owner's Costs, 2013 MM$														
Total Project Costs, 2013 MM$														
Total Project Costs, 2013 $/kW														
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)														
NO_X	0.007	0.007	0 007	0.007	0.007	0 007	0.033	0.033	0 018	0.018	0.035	0.035	0.001	0.001
SO_2	< 0.0051	< 0 0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0 0051	1.24E-05	1.24E-05
CO	0.004	0.004	0.004	0.004	0.004	0.004	0.020	0.020	0 034	0.034	0.096	0 096	0.100	0.100
CO_2	120	120	120	120	120	120	120	120	120	120	120	120	120	120
PM/PM_{10}	0.01	0.01	0 01	0.01	0.01	0 01	0.01	0.01	0.01	0.01	0.01	0.01	2.49E-06	2.49E-06
VOC	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0 003	0.003	0.009	0 009	0.001	0.001
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh														
NO_X	0.070	0.070	0 070	0.070	0.080	0 080	0.330	0.330	0.160	0.150	0.400	0.400	0.010	0.010
SO_2	< 0.049	< 0.049	< 0 045	< 0.045	< 0.059	< 0.059	< 0.051	< 0.051	< 0.043	< 0.043	< 0.058	< 0.058	1.00E-04	1.00E-04
CO	0.040	0.040	0.040	0.040	0.050	0.050	0.200	0.200	0 290	0.280	1.10	1.10	0.80	0.80
CO_2	1160	1160	1070	1070	1380	1380	1190	1190	1020	1010	1330	1330	940	940
PM/PM_{10}	0.10	0.10	0 09	0.09	0.12	0.12	0.10	0.10	0.08	0.08	0.11	0.11	2.00E-05	2.00E-05
VOC	0.03	0.03	0 02	0.02	0.03	0 03	0.03	0.03	0.02	0.02	0.10	0.10	0.01	0.01

Notes

Note 1: Simple cycle starts are not affected by hot, warm or cold conditions.
Note 2: For the Wärtsilä engines, if the engine jacket temperature is above 185 F, the engine can start in 5 mins. If the engine jacket temperature is between 120 F and 185F, the engine will take 1-2 hours to get to full load. If the engine jacket is less than 120 F, the preheaters will need to run to get the engine to 120 F. Once at 120 F, the engine will take 1-2 hours to get to full load, but it could take 6+ hours to get to 120 F.
Note 3: This reflects a traditional start for an "F class" gas turbine. With a purge credit, the GT can start in 20 mins. Fast start capability is also possible at 12 mins, however the GT major maintenance $/start cost doubles for each fast start.
Note 4: Fuel Cell requires 72 hour warmup period. After warmup, a maximum ramp rate of approximately 5 kW/min is allowable without maintenance penalties. Maximum possible ramp rate is 400 kW/min with risk to BOP and Cell module equipment. Note 1 above also applies in addition to Note 4.

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
NATURAL GAS COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-2
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PROJECT TYPE	1x1 F-Class CCGT		1x1 Advanced Class CCGT		1x1 Emerging Advanced Class CCGT		2x1 F-Class CCGT		2x1 Advanced Class CCGT		2x1 Emerging Advanced Class CCGT		3x1 F-Class CCGT		3x1 Advanced Class CCGT		3x1 Emerging Advanced Class CCGT	
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired
Number of Gas Turbines	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3
Number of Steam Turbines	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F-5		MHI GAC		MHI JAC		GE 7F-5		MHI GAC		MHI JAC		GE 7F-5		MHI GAC		MHI JAC	
Steam Conditions (Main Steam / Reheat)	1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F		1050 F/1050 F	
Main Steam Pressure	2400 psia		2400 psia		2400 psia		2400 psia		2400 psia		2400 psia		2400 psia		2400 psia		2400 psia	
Steam Cycle Type	Subcritical		Subcritical		Subcritical		Subcritical		Subcritical		Subcritical		Subcritical		Subcritical		Subcritical	
Capacity Factor (%)	Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)		Intermediate (50%)	
Startup Time (Cold Start) - Shut down >= X Hours	4 Hours		4 Hours		4 Hours		4 Hours		4 Hours		4 Hours		4 Hours		4 Hours		4 Hours	
Startup Time (Warm Start) - Shut down >= X Hours	2 Hours		2 Hours		2 Hours		2 Hours		2 Hours		2 Hours		2 Hours		2 Hours		2 Hours	
Startup Time (Hot Start) - Shut down <= X Hours	1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours		1.5 Hours	
Maximum Ramp Rate (Online)	10%/min		10%/min		10%/min		10%/min		10%/min		10%/min		10%/min		10%/min		10%/min	
Forced Outage Factor (%)	3.19%		3.19%		3.19%		3.19%		3.19%		3.19%		3.19%		3.19%		3.19%	
Equivalent Forced Outage Rate (%)	9.11%		9.11%		9.11%		9.11%		9.11%		9.11%		9.11%		9.11%		9.11%	
Availability Factor (%)	89.54%		89.54%		89.54%		89.54%		89.54%		89.54%		89.54%		89.54%		89.54%	
Fuel Design	Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas		Natural Gas	
Heat Rejection	Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower	
NO_x Control	DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR		DLN/SCR	
CO Control	Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst		Oxidation Catalyst	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature		Mature		Mature		Mature		Mature		Mature		Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	4 Years		4 Years		4 Years		4 Years		4 Years		4 Years		4 Years		4 Years		4 Years	
ESTIMATED PERFORMANCE																		
Base Load Performance @ 20°F (Winter Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		
Incremental Duct Fired Performance @ 20 F (Winter Average)																		
Incremental Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental Net Plant Heat Rate, Btu/kWh (HHV)																		
Incremental Heat Input, MMBtu/h (HHV)																		
Minimum Load Operational Status @ 20 F (Winter Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		
Base Load Performance @ 59 F (Annual Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		
Incremental Duct Fired Performance @ 59 F (Annual Average)																		
Incremental Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental Net Plant Heat Rate, Btu/kWh (HHV)																		
Incremental Heat Input, MMBtu/h (HHV)																		
Minimum Load Operational Status @ 59 F (Annual Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		
Base Load Performance @ 90 F (Summer Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		
Incremental Duct Fired Performance @ 90 F (Summer Average)																		
Incremental Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental Net Plant Heat Rate, Btu/kWh (HHV)																		
Incremental Heat Input, MMBtu/h (HHV)																		
Minimum Load Operational Status @ 90 F (Summer Average)																		
Net Plant Output, kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant Heat Rate, Btu/kWh (HHV)																		
Heat Input, MMBtu/h (HHV)																		

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
NATURAL GAS COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-2
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PROJECT TYPE	1x1 F-Class CCGT		1x1 Advanced Class CCGT		1x1 Emerging Advanced Class CCGT		2x1 F-Class CCGT		2x1 Advanced Class CCGT		2x1 Emerging Advanced Class CCGT		3x1 F-Class CCGT		3x1 Advanced Class CCGT		3x1 Emerging Advanced Class CCGT	
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired	Unfired	Fired
ESTIMATED CAPITAL AND O&M COSTS																		
EPC Project Capital Costs, 2013 MM$ (w/o Owner's Costs)	[redacted]																	
Owner's Costs, 2013 MM$																		
Owner's Project Development																		
Owner's Operational Personnel Prior to COD																		
Owner's Engineer																		
Owner's Project Management																		
Owner's Legal Costs																		
Owner's Start-up Engineering																		
Temporary Utilities																		
Operator Training																		
Permitting and Licensing Fees																		
Site Water Supply and Discharge																		
Switchyard																		
Political Concessions & Area Development Fees																		
Startup/Testing (Fuel & Consumables)																		
Site Security																		
Operating Spare Parts																		
Permanent Plant Equipment and Furnishings																		
Builders Risk Insurance (0.45% of Construction Costs)																		
Owner's Contingency (5% for Screening Purposes)																		
Owner's Costs, 2013 MM$																		
Total Project Costs, 2013 MM$																		
Total Project Costs, 2013 $/Unfired kW																		
Total Project Costs, 2013 $/Fired kW																		
Fixed O&M Cost, 2013$/kW-Yr																		
Incremental Duct Fired Fixed O&M Cost, 2013$/kW-Yr																		
Levelized Major Maintenance Cost, 2013$/GTG-hr																		
Levelized Major Maintenance Cost, 2013$/GT-Start																		
Incremental Duct Fired Levilized Major Maintenance Cost, 2013$/MWh																		
Variable O&M Cost, 2013$/MWh (excl. GT major maint.)																		
Incr. Duct Fired Variable O&M, 2013$/MWh (excl. major maint.)																		
Water Consumption, gpm																		
Start-up Fuel Consumption, MMBtu/Cold Start																		
Start-up Fuel Consumption, MMBtu/Warm Start																		
Start-up Fuel Consumption, MMBtu/Hot Start																		
Start-up Power Generation, kWh/Cold Start																		
Start-up Power Generation, kWh/Warm Start																		
Start-up Power Generation, kWh/Hot Start																		
DUAL FUEL CAPABILITY ADD-ON COST																		
EPC Capital Cost, 2013 MM$ (w/o Owner's Costs)																		
Owner's Costs, 2013 MM$																		
Total Project Costs, 2013 MM$																		
Total Project Costs, 2013 $/kW Unfired																		
Total Project Costs, 2013 $/kW Fired																		
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)																		
NO_X	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
SO_2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051
CO	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
CO_2	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
PM/PM_{10}	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
VOC	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh																		
NO_X	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
SO_2	< 0.034	< 0.034	< 0.033	< 0.034	< 0.032	< 0.032	< 0.033	< 0.034	< 0.033	< 0.034	< 0.032	< 0.032	< 0.033	< 0.034	< 0.033	< 0.034	< 0.031	< 0.032
CO	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
CO_2	790	800	780	790	750	750	780	800	780	790	740	750	780	790	780	790	740	750
PM/PM_{10}	0.07	0.07	0.07	0.07	0.06	0.06	0.07	0.07	0.07	0.07	0.06	0.06	0.07	0.07	0.06	0.07	0.06	0.06
VOC	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL FIRED TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-3
November 2013 - Revision 0

PROJECT TYPE	**Subcritical Pulverized Coal**		**Circulating Fluidized Bed**		**Supercritical Pulverized Coal 500 MW**		**Supercritical Pulverized Coal 750 MW**		**2x1 Integrated Gasification CC**	
BASE PLANT DESCRIPTION	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture
Nominal Output	500 MW	430 MW	500 MW	430 MW	500 MW	430 MW	750 MW	640 MW	620 MW	480 MW
Number of Gas Turbines	N/A		N/A		N/A		N/A		2	
Number of Boilers/Reactors	1		2		1		1		N/A	
Number of Steam Turbines	1		1		1		1		1	
Steam Conditions (Main Steam / Reheat)	1050 F/1050F		1050 F/1050F		1050 F/1050F		1050 F/1050F		1050 F/1050F	
Main Steam Pressure	2535 psia		2535 psia		3675 psia		3675 psia		1900 psia	
Steam Cycle Type	Subcritical		Subcritical		Supercritical		Supercritical		Subcritical	
Capacity Factor (%)	Baseload (85%)		Baseload (85%)		Baseload (85%)		Baseload (85%)		Baseload (85%)	
Startup Time (Cold Start)	6 Hours		10 Hours		10 Hours		10 Hours		45 Hours	
Startup Time (Warm Start)	3 Hours		6 Hours		6 Hours		6 Hours		10 Hours	
Startup Time (Hot Start)	1.5 Hours		4 Hours		4 Hours		4 Hours		4 Hours	
Forced Outage Factor (%)	4.07%		4.07%		4.07%		4.07%		10-14%	
Equivalent Forced Outage Rate (%)	5.20%		5.20%		5.20%		5.20%		12%	
Availability Factor (%)	90%		90%		90%		90%		80%	
Fuel Design	Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous		Illinois Basin Bituminous	
Heat Rejection	Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower		Wet Cooling Tower	
NO_x Control	SCR		SNCR		SCR		SCR		Nitrogen Injection, SCR	
SO_2 Control	Wet Scrubber		Dry Scrubber		Wet Scrubber		Wet Scrubber		Selexol	
Ash Disposal	Landfill		Landfill		Landfill		Landfill		N/A	
Particulate Control	Baghouse		Baghouse		Baghouse		Baghouse		Good Combustion Practice	
Technology Rating	Mature		Mature		Mature		Mature		Developmental	
Permitting & Construction Schedule (Years from FNTP)	7.5 Years		7.5 Years		7.5 Years		7.5 Years		7.5 Years	
ESTIMATED PERFORMANCE										
Base Load Performance @ 59 F (Annual Average)										
Net Plant Output, kW	500,000	425,000	500,000	425,000	500,000	425,000	750,000	637,500	618,000	482,000
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Minimum Load Operational Status @ 59 F (Annual Average)										
Net Plant Output, kW	175,000	149,000	88,000	74,000	175,000	149,000	263,000	223,000	216,000	169,000
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)										

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL FIRED TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-3
November 2013 - Revision 0

PROJECT TYPE	**Subcritical Pulverized Coal**		**Circulating Fluidized Bed**		**Supercritical Pulverized Coal 500 MW**		**Supercritical Pulverized Coal 750 MW**		**2x1 Integrated Gasification CC**	
BASE PLANT DESCRIPTION	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture	w/o Carbon Capture	w/Carbon Capture
ESTIMATED CAPITAL AND O&M COSTS										
Project Capital Costs, 2013 MM$ (w/o Owner's Costs)	[redacted]									
Owner's Costs, 2013 MM$										
Owner's Project Development										
Owner's Operational Personnel Prior to COD										
Owner's Engineer										
Owner's Project Management										
Owner's Legal Costs										
Owner's Start-up Engineering										
Operator Training										
Construction Power and Water										
Permitting and Licensing Fees										
Site Water Supply and Discharge										
Switchyard										
Political Concessions & Area Development Fees										
Startup/Testing (Fuel & Consumables)										
Initial Fuel Inventory										
Site Security										
Operating Spare Parts										
Permanent Plant Equipment and Furnishings										
Builders Risk Insurance (0.45% of Construction Costs)										
Owner's Contingency (5% for Screening Purposes)										
Owner's Costs, 2013 MM$										
Total Project Costs, 2013 MM$										
Total Project Costs, 2013 $/kW										
Fixed O&M Cost, 2013$/kW-Yr										
Levelized Major Maintenance Cost, 2013$/MWhr										
Variable O&M Cost, 2013$/MWh (excl. major maint.)										
Water Consumption, gpm										
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)										
NO_X	0.04	0.02	0.06	0.03	0.04	0.02	0.04	0.02	0.019	0.018
SO_2	0.04	0.02	0.05	0.03	0.04	0.02	0.04	0.02	0.016	0.008
CO	0.15	0.15	0.10	0.10	0.15	0.15	0.15	0.15	0.049	0.049
CO_2	200	103	200	102	200	105	200	107	200	96
Hg (lb/Tbtu)	0.33	0.28	0.33	0.28	0.34	0.29	0.34	0.29	0.34	0.29
PM/PM_{10} (filterable)	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.022	0.022
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh										
NO_X	0.36	0.21	0.55	0.32	0.36	0.21	0.35	0.20	0.17	0.21
SO_2	0.36	0.21	0.46	0.27	0.36	0.21	0.35	0.20	0.14	0.09
CO	1.37	1.61	0.92	1.08	1.34	1.57	1.31	1.54	0.44	0.56
CO_2	1820	1100	1840	1100	1780	1100	1740	1100	1790	1100
Hg	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06
PM/PM_{10}	0.300	0.353	0.304	0.357	0.294	0.346	0.287	0.338	0.20	0.25

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
WASTE - TO - ENERGY TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-4
November 2013 - Revision 2

PROJECT TYPE	**MSW Stoker Fired**	**RDF Stoker Fired**	**Wood Stoker Fired**	**Landfill Gas IC Engine**	**Anaerobic Digester Gas IC Engine**	**Co-fired Circulating Fluidized Bed (CFB) 50% Coal / 50% Biomass**	**Existing PC Boiler Conversion to Co-fire 90% Coal / 10% Biomass**
BASE PLANT DESCRIPTION							
Nominal Output	50 MW	50 MW	50 MW	5 MW	5 MW	50 MW	100 MW
Number of Boilers/Reactors/Engines	1	1	1	1 Recip Engine	1 Recip Engine	1	1
Number of Steam Turbines	1	1	1	N/A	N/A	1	1
Steam Conditions (Main Steam / Reheat)	950 F/950F	950 F/950F	950 F/950F	N/A	N/A	1050 F/1050 F	1050F/1050F
Main Steam Pressure	1400 psia	1400 psia	1400 psia	N/A	N/A	2535 psia	2535 psia
Steam Cycle Type	Subcritical	Subcritical	Subcritical	N/A	N/A	Subcritical	Subcritical
Capacity Factor (%)	Baseload (85%)	Baseload (85%)	Baseload (85%)	Peaking (25%)	Peaking (25%)	Baseload (85%)	Baseload (85%)
Startup Time (Cold Start)	8 Hours	8 Hours	8 Hours	6+ Hours (Note 1)	6+ Hours (Note 1)	10 Hours	6 Hours
Startup Time (Warm Start)	1-2 Hours	1-2 Hours	1-2 Hours	1-2 Hours (Note 1)	1-2 Hours (Note 1)	1-2 Hours	3 Hours
Startup Time (Hot Start)	45 Minutes	45 Minutes	45 Minutes	5 Minutes (Note 1)	5 Minutes (Note 1)	45 Minutes	1.5 Hours
Forced Outage Factor (%)	4 07%	4 07%	4 07%	1 80%	1 80%	4.07%	4.07%
Equivalent Forced Outage Rate (%)	6 38%	6 38%	6 38%	27.40%	27.40%	6.38%	6.38%
Availability Factor (%)	90%	90%	90%	91 8%	91 8%	90%	90%
Fuel Design	100 % Municipal Solid Waste	100% Refuse-Derived Fuel	100% Chipped Wood Biomass	100% Landfill Gas	100% Sewage Bio-gas	Up to 100% Wood OR Up to 100% Coal	Up to 10% Wood / Up to 100% Coal
Performance Basis	100 % Municipal Solid Waste	100% Refuse-Derived Fuel	100% Chipped Wood Biomass	100% Landfill Gas	100% Sewage Bio-gas	50% IL Basin Coal / 50% Chipped Wood Biomass	10% Wood Biomass / 90% L Basin Coal
Heat Rejection	Wet Cooling Tower	Wet Cooling Tower	Wet Cooling Tower	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Wet Cooling Tower	Wet Cooling Tower
NO_x Control	SNCR	SNCR	SNCR	SCR	SCR	SNCR	SCR
CO Control	Good Combustion Practices	Good Combustion Practices	Good Combustion Practices	Oxidation Catalyst	Oxidation Catalyst	Good Combustion Practices	Good Combustion Practices
SO_2 Control	Dry Sorbent Injection	Dry Sorbent Injection	Dry Sorbent Injection	None	None	Limestone Bed Injection/ Polishing FGD	Wet FGD
Mercury Control	Dry Sorbent Injection	Dry Sorbent Injection	Dry Sorbent Injection	N/A	N/A	Dry Sorbent Injection	Dry Sorbent Injection
Ash Disposal	On-Site Landfill	On-Site Landfill	On-Site Landfill	N/A	N/A	On-Site Landfill	On-Site Landfill
Particulate Control	Baghouse	Baghouse	Baghouse	Good Combustion Practice	Good Combustion Practice	Baghouse	Baghouse
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3.5	3 5	3 5	2 5	2 5	3 5	1.5
ESTIMATED PERFORMANCE							
Base Load Performance @ 59° F (Annual Average)							
Net Plant Output, kW	50,000	50,000	50,000	5,000	5,000	50,000	100,000
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)							
Minimum Load Operational Status @ 59° F (Annual Average)							
Net Plant Output, kW	17,500	17,500	17,500	2,500	2,500	17,500	35,000
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input, MMBtu/h (HHV)							

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
WASTE - TO - ENERGY TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-4
November 2013 - Revision 2

PROJECT TYPE	MSW Stoker Fired	RDF Stoker Fired	Wood Stoker Fired	Landfill Gas IC Engine	Anaerobic Digester Gas IC Engine	Co-fired Circulating Fluidized Bed (CFB) 50% Coal / 50% Biomass	Existing PC Boiler Conversion to Co-fire 90% Coal / 10% Biomass
ESTIMATED CAPITAL AND O&M COSTS							
Project Capital Costs, 2013 MM$ (w/o Owner's Costs)	[redacted]						
Owner's Costs, 2013 MM$							
Owner's Project Development							
Owner's Operational Personnel Prior to COD							
Owner's Engineer							
Owner's Project Management							
Owner's Legal Costs							
Owner's Start-up Engineering							
Operator Training							
Construction Power and Water							
Permitting and Licensing Fees							
Site Water Supply and Discharge							
Switchyard							
Political Concessions & Area Development Fees							
Startup/Testing (Fuel & Consumables)							
Initial Fuel Inventory							
Site Security							
Operating Spare Parts							
Permanent Plant Equipment and Furnishings							
Builders Risk Insurance (0.45% of Construction Costs)							
Owner's Contingency (5% for Screening Purposes)							
Owner's Costs, 2013 MM$							
Total Project Costs, 2013 MM$							
Total Project Costs, 2013 $/kW							
Fixed O&M Cost, 2013$/kW-Yr							
Variable O&M Cost, 2013$/MWh (incl. major maint.)							
Raw Water Consumption, gpm	500	500	500	<10	<10	500	0
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)							
NO_X	0.10	0.10	0.10	0.02	0.02	0 06	0 04
SO_2	0.03	0.03	0.03	0.01	0.01	0.03	0 04
CO	0.15	0.15	0.15	0.05	0.05	0.13	0.15
CO_2	205	205	205	180	180	203	200
Hg (lb/TBtu)	0.8	0 8	0 8	--	--	0.56	0 33
PM/PM_{10}	0 033	0 033	0 033	0 033	0 033	0.033	0.033
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh							
NO_X	1.50	1.40	1.40	0.20	0.20	0 60	0 30
SO_2	0.40	0.40	0.30	0.10	0.10	0.30	0 30
CO	2.20	2.10	2.00	0.50	0.50	1.30	1.40
CO_2	3030	2910	2790	1910	1800	2150	1840
Hg	1.18E-05	1.14E-05	1.09E-05	--	--	6.00E-06	3.00E-06
PM/PM_{10}	0.50	0.50	0.40	0.30	0.30	0.30	0 30

Notes
Note 1: For the Wärtsilä engines, if the engine jacket temperature is above 185 F, the engine can start in 5 mins. If the engine jacket temperature is between 120 F and 185F, the engine will take 1-2 hours to get to full load. If the engine jacket is less than 120 F, the preheaters will need to run to get the engine to 120 F. Once at 120 F, the engine will take 1-2 hours to get to full load, but it could take 6+ hours to get to 120 F.
Note 2: PC Co-firing conversion assumes that the existing coal PC plant is already functional. The estimate accounts for the conversion investment only.

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LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE - RENEWABLES - NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-5
November 2013 - Revision 0

PROJECT TYPE	Pumped Hydro Energy Storage	Adv. Battery Energy Storage	CAES	Wind Energy Conversion	Solar Photovoltaic	Solar Thermal	HydroElectric	Small Modular Nuclear
BASE PLANT DESCRIPTION								
Nominal Output	200 MW	10 MW	135 MW	50 MW	50 MW	50 MW	50 MW	225 MW
Number of Boilers/Reactors/Turbines	N/A	N/A	1	N/A	N/A	N/A	N/A	1
Number of Steam Turbines	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1
Capacity Factor (%)	N/A	N/A	N/A	Intermittent (27%)	Intermittent (19%)	Intermittent (19%)	N/A	Base (83%)
Startup Time (Cold Start)	N/A	N/A	10 Minutes	N/A	N/A	N/A	N/A	170 Hours
Forced Outage Factor (%)	N/A	N/A	3.19%	5 00%	3.00%	3.00%	N/A	5.95%
Equivalent Forced Outage Rate (%)	N/A	N/A	9.11%	7 00%	3.13%	3.13%	N/A	7.91%
Availability Factor (%)	N/A	N/A	> 96%	98%	98%	98%	N/A	83%
Storage Efficiency (%)	80%	85%	Incl. in Heat Rate	N/A	N/A	N/A	N/A	N/A
Fuel Design	N/A	N/A	Natural Gas	N/A	N/A	N/A	N/A	N/A
Heat Rejection	N/A	N/A	N/A	N/A	N/A	Cooling Tower	N/A	N/A
NO_x Control	N/A	N/A	SCR	N/A	N/A	N/A	N/A	N/A
CO Control	N/A	N/A	CO Catalyst	N/A	N/A	N/A	N/A	N/A
SO_2 Control	N/A	N/A	Good Combustion Practice	N/A	N/A	N/A	N/A	N/A
Particulate Control	N/A	N/A	Good Combustion Practice	N/A	N/A	N/A	N/A	N/A
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Developmental
Permitting & Construction Schedule (Years from FNTP)	4.0 Years	1 5 Years	1.5 Years	2.5 Years	2 0 Years	2.0 Years	4.0 Years	7 0 Years
ESTIMATED PERFORMANCE								
Base Load Performance @ (Annual Average)								
Net Plant Output, kW	200,000	10,000	135,000	50,000	50,000	50,000	50,000	225,000
Net Plant Heat Rate, Btu/kWh (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Input MMBtu/h (HHV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ESTIMATED CAPITAL AND O&M COSTS								
Project Capital Costs, 2013 MM$ (w/o Owner's Costs)	[redacted]							
Owner's Costs, 2013 MM$								
Owner's Project Development								
Owner's Operational Personnel Prior to COD								
Owner's Engineer								
Owner's Project Management								
Owner's Legal Costs								
Owner's Start-up Engineering								
Construction Power and Water								
Permitting and Licensing Fees								
Site Water Supply and Discharge								
Switchyard								
Political Concessions & Area Development Fees								
Startup/Testing (Fuel & Consumables)								
Site Security								
Operating Spare Parts								
Permanent Plant Equipment and Furnishings								
Builders Risk Insurance (0.45% of Construction Costs)								
Owner's Contingency (5% for Screening Purposes)								
Owner's Costs, 2013 MM$								
Total Project Costs, 2013 MM$								
Total Project Costs, 2013 $/kW								
Fixed O&M Cost, 2013$/kW-Yr								
Levelized Major Maintenance Cost, 2013$/MWh								
Variable O&M Cost 2013$/MWh (excl. major maint.)								

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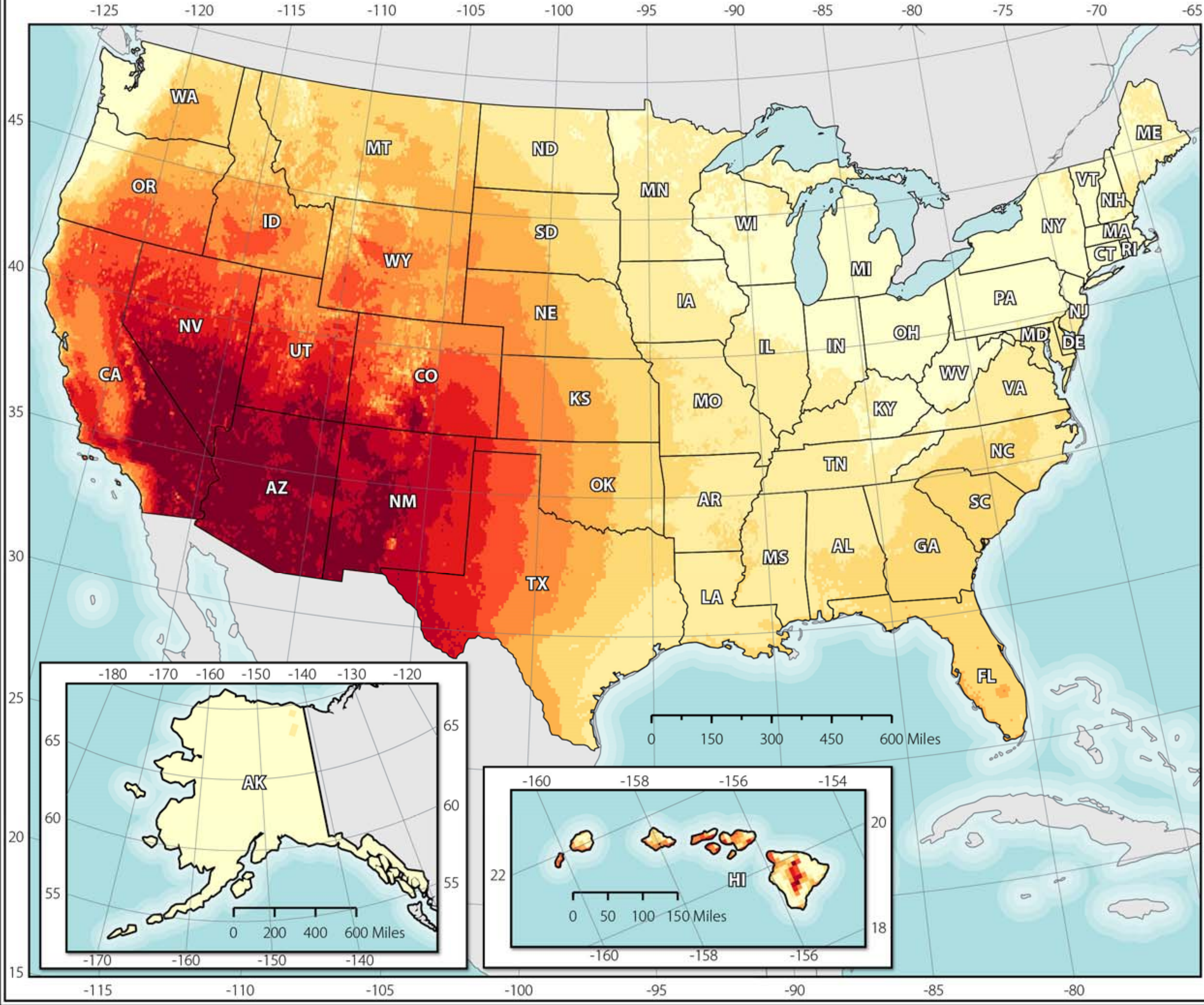
LG&E/KU TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE - RENEWABLES - NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX A-5
November 2013 - Revision 0

PROJECT TYPE	Pumped Hydro Energy Storage	Adv. Battery Energy Storage	CAES	Wind Energy Conversion	Solar Photovoltaic	Solar Thermal	HydroElectric	Small Modular Nuclear
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MMBtu (HHV)								
NO_X	N/A	N/A	0 004	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	< 0 0051	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	0.002	N/A	N/A	N/A	N/A	N/A
PM/PM_{10}	N/A	N/A	0 01	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	0.003	N/A	N/A	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS, lb/MWh								
NO_X	N/A	N/A	0 037	N/A	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	< 0.03	N/A	N/A	N/A	N/A	N/A
CO_2	N/A	N/A	0.022	N/A	N/A	N/A	N/A	N/A
PM/PM_{10}	N/A	N/A	0 05	N/A	N/A	N/A	N/A	N/A
VOC	N/A	N/A	0 02	N/A	N/A	N/A	N/A	N/A

Appendix B

Renewable Resource Maps

Concentrating Solar Resource of the United States



kWh/m²/Day

- > 7.5
- 7.0 to 7.5
- 6.5 to 7.0
- 6.0 to 6.5
- 5.5 to 6.0
- 5.0 to 5.5
- 4.5 to 5.0
- 4.0 to 4.5
- < 4.0

Annual average direct normal solar resource data are shown. The data for Hawaii and the 48 contiguous states are a 10km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2009.

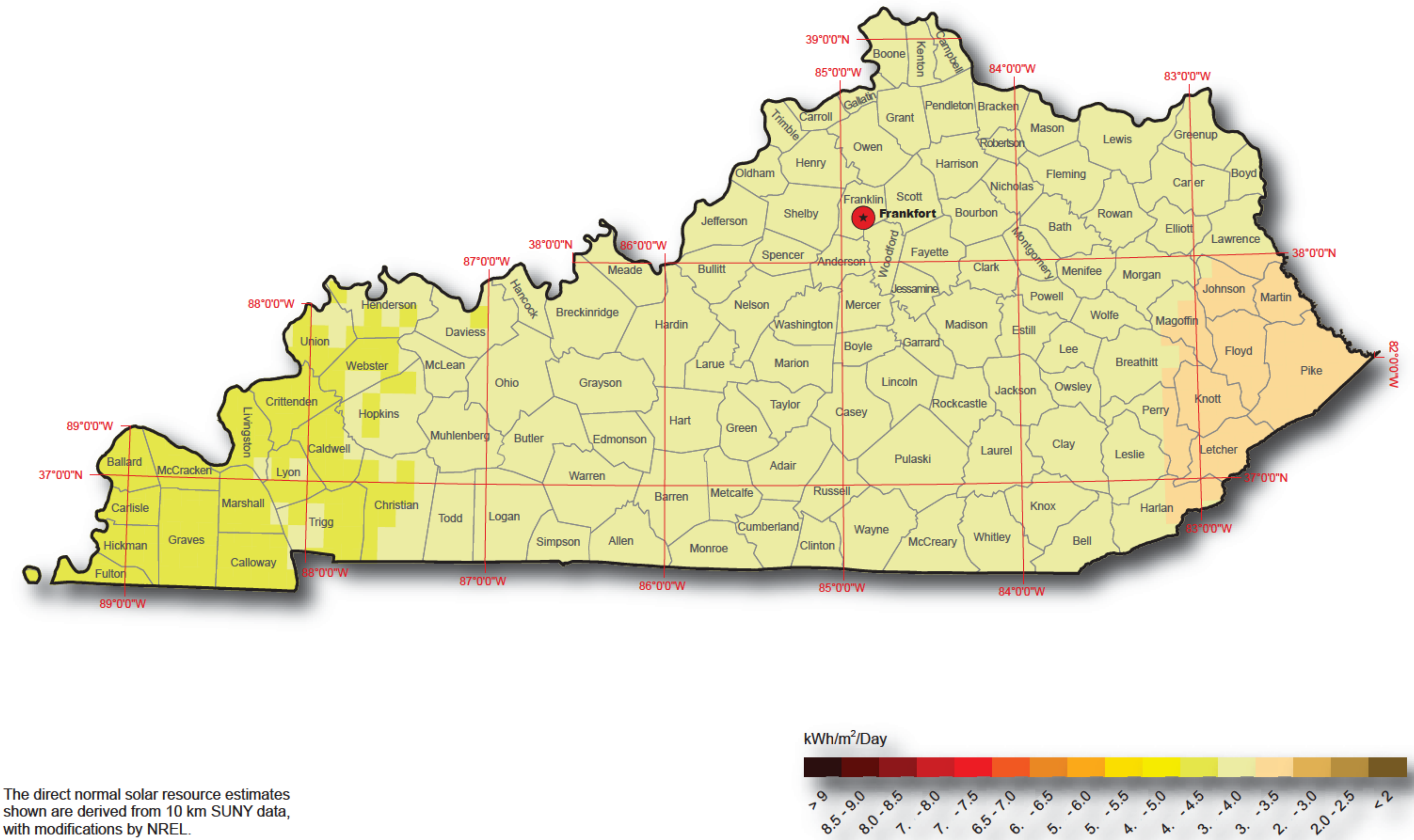
The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Billy J. Roberts
19 September 2012

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Concentrating Solar Power Resource

Kentucky



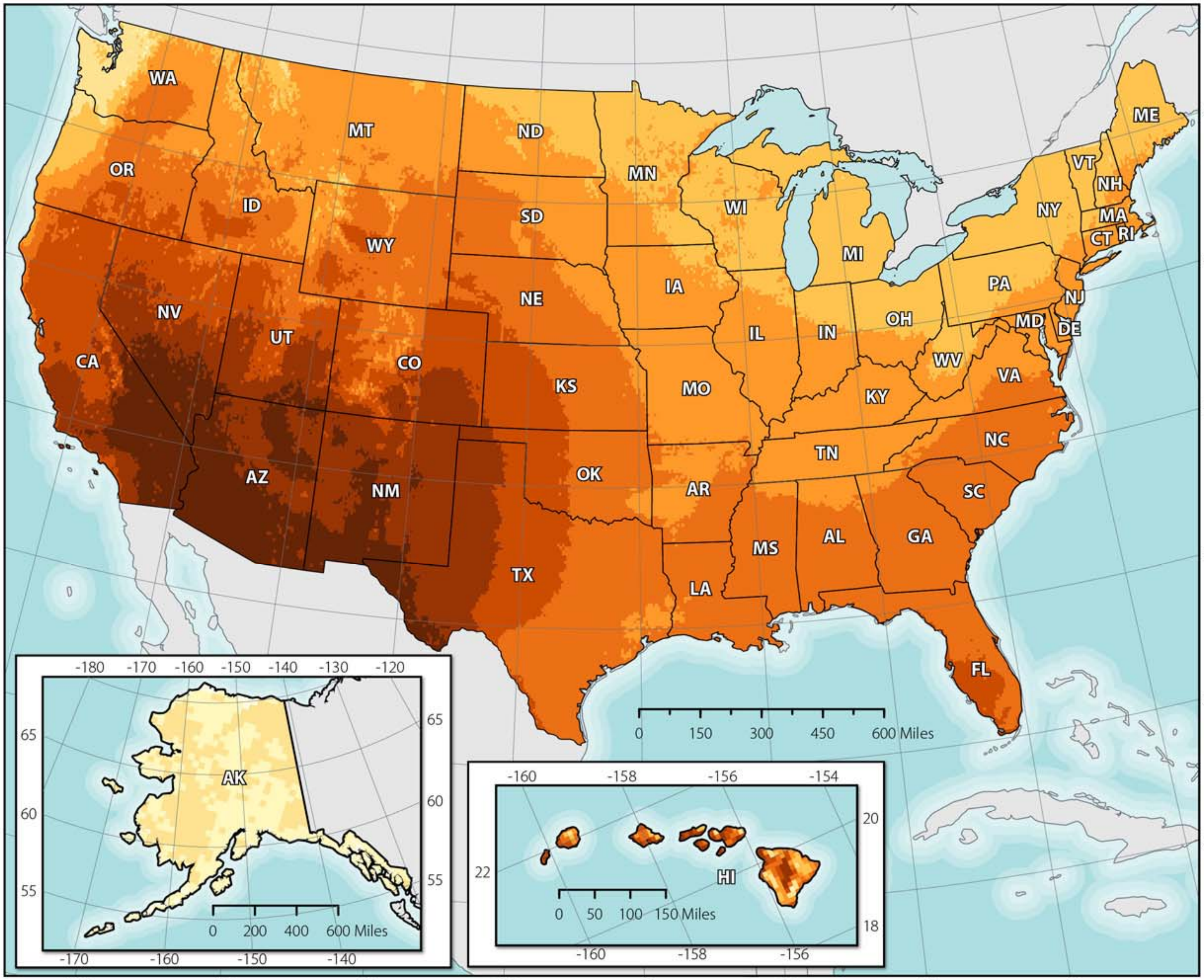
The direct normal solar resource estimates shown are derived from 10 km SUNY data, with modifications by NREL.

0 30 60 120 Miles

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy. September 25, 2007

NREL

Photovoltaic Solar Resource of the United States



Annual average solar resource data are shown for a tilt = latitude collector. The data for Hawaii and the 48 contiguous states are a 10km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2009.

The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Billy J. Roberts
19 September 2012

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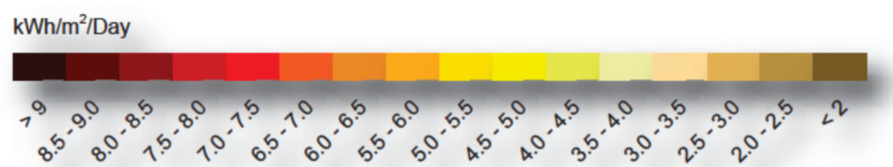
Global Solar Radiation at Latitude Tilt - Annual

Kentucky

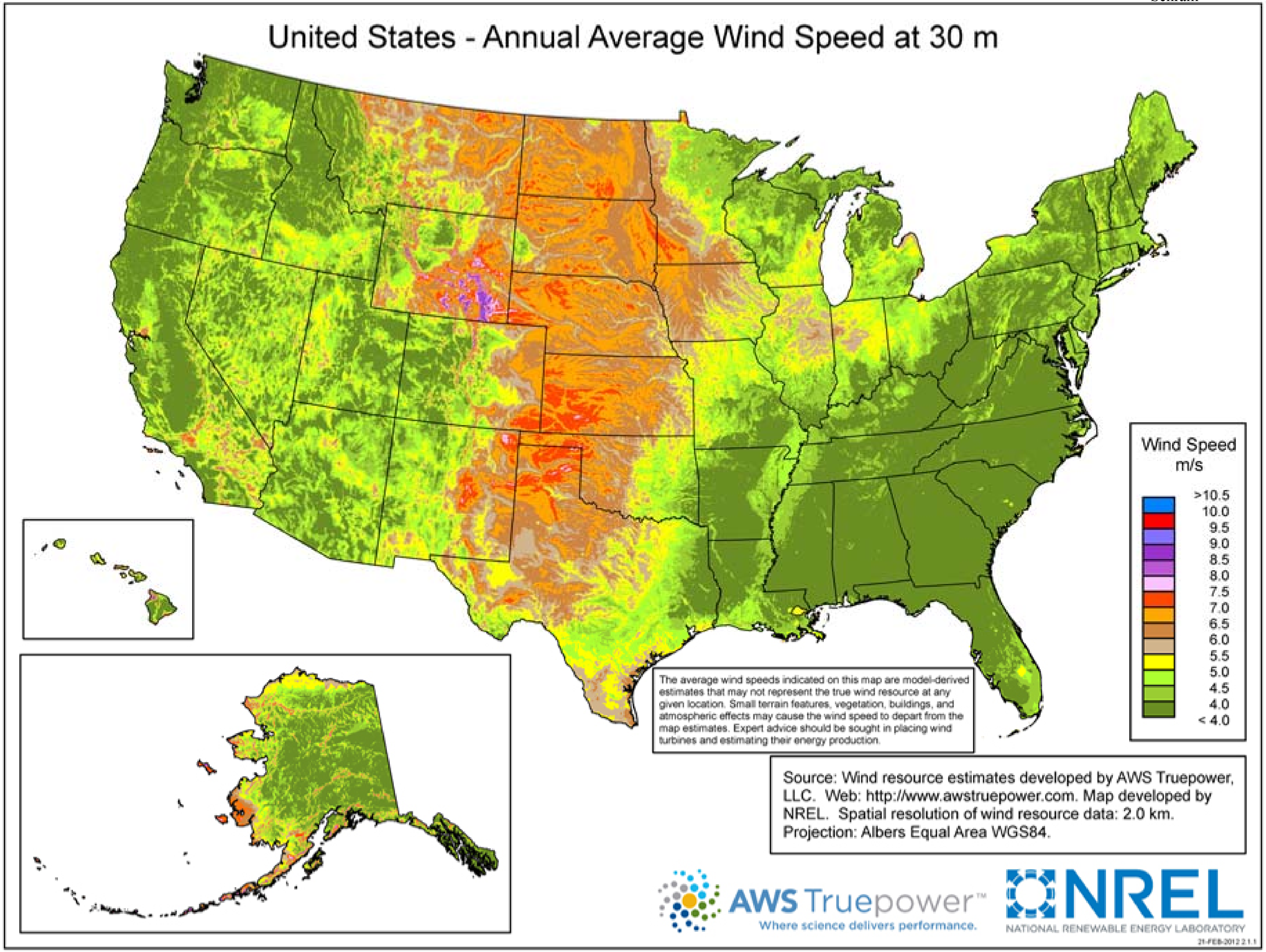


Model estimates of monthly average daily total radiation, averaged from hourly estimates of direct normal irradiance over 8 years (1998-2005). The model inputs are hourly visible irradiance from the GOES geostationary satellites, and monthly average aerosol optical depth, precipitable water vapor, and ozone sampled at a 10km resolution.

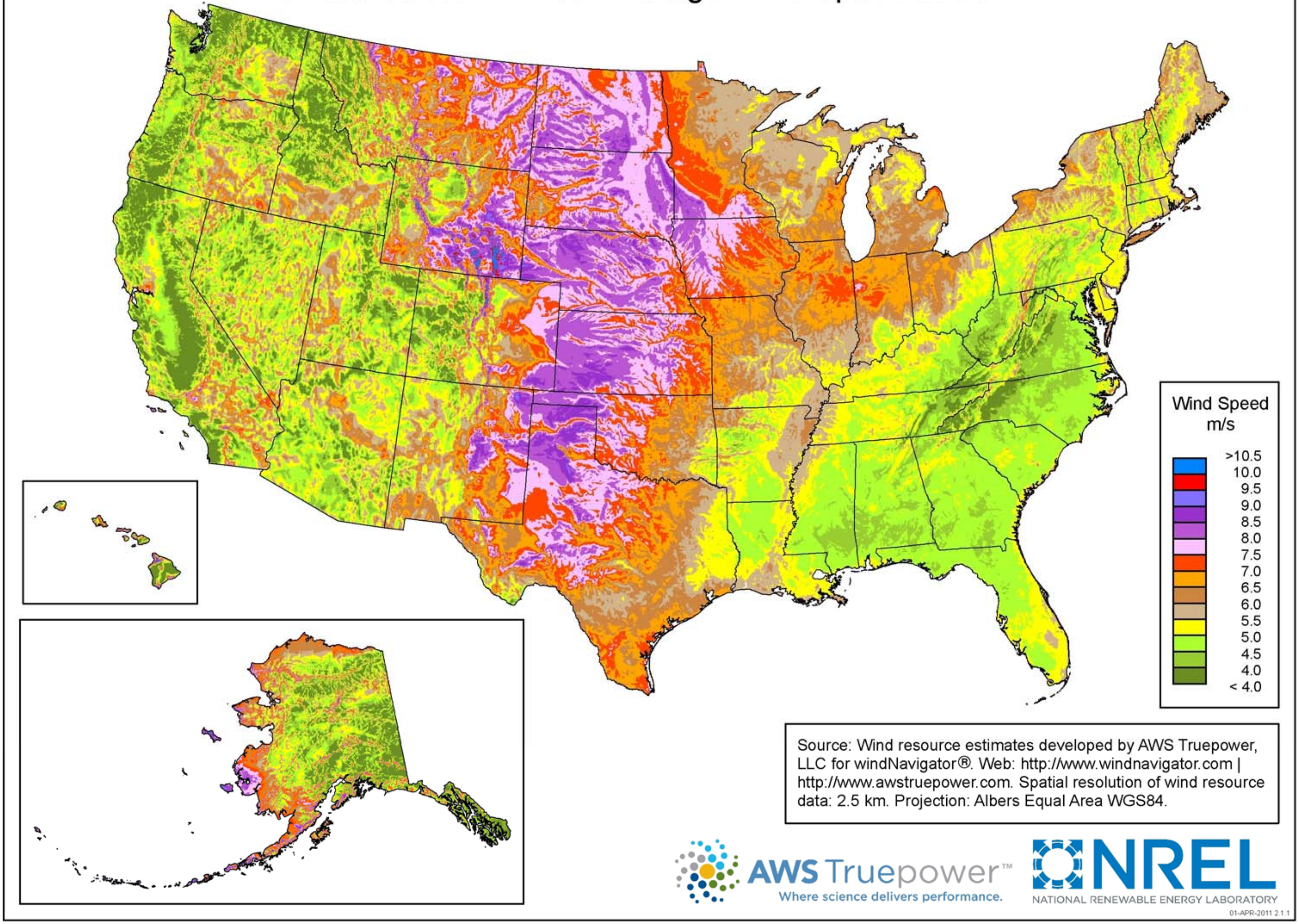
Miles
0 15 30 60

This map was produced by
the National Renewable Energy Laboratory
for the U.S. Department of Energy.
September 25, 2007

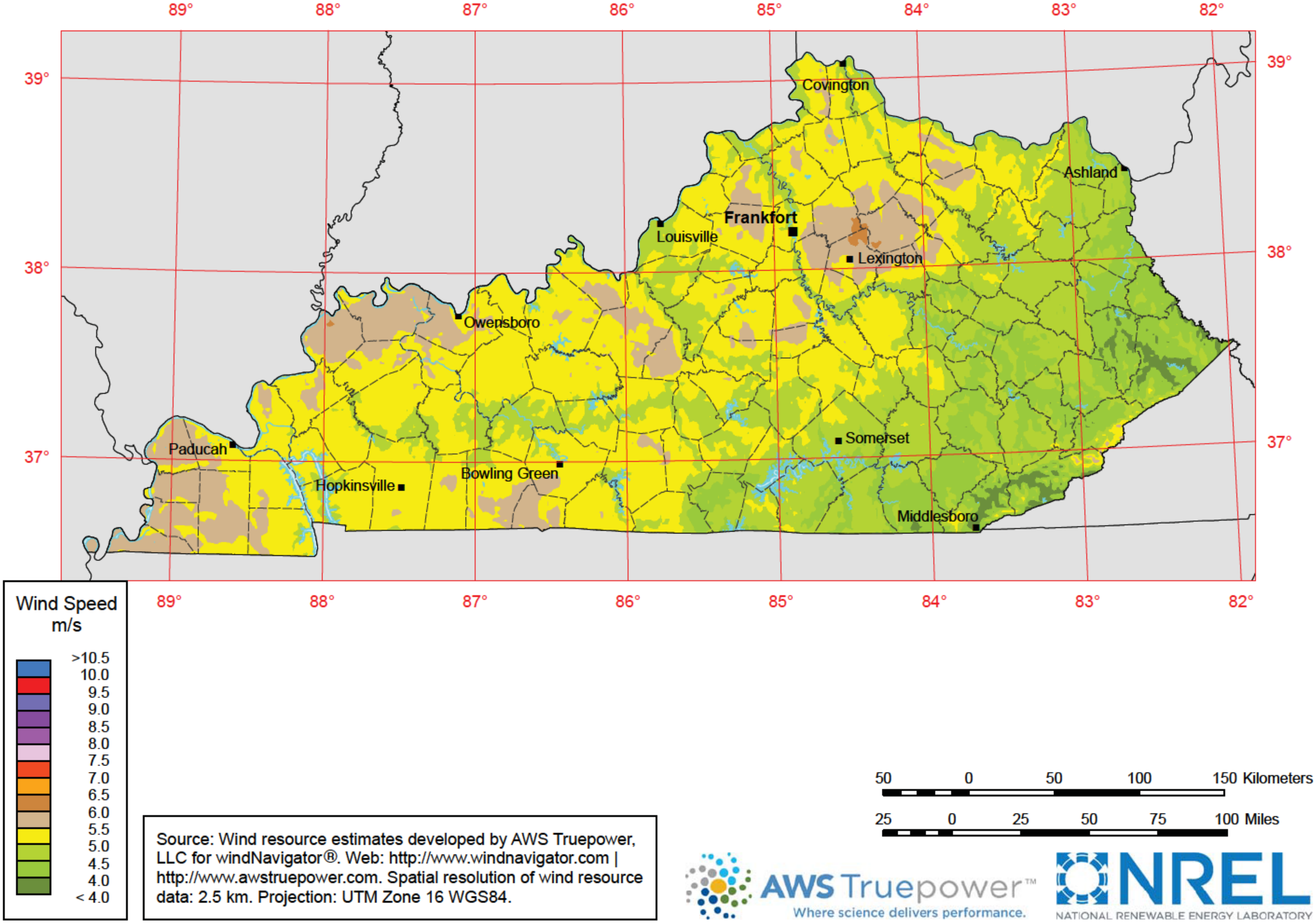
NREL


United States - Annual Average Wind Speed at 30 m
Wind Speed m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
The average wind speeds indicated on this map are model-derived estimates that may not represent the true wind resource at any given location. Small terrain features, vegetation, buildings, and atmospheric effects may cause the wind speed to depart from the map estimates. Expert advice should be sought in placing wind turbines and estimating their energy production.
Source: Wind resource estimates developed by AWS Truepower, LLC. Web: http://www.awstruepower.com. Map developed by NREL. Spatial resolution of wind resource data: 2.0 km. Projection: Albers Equal Area WGS84.
AWS Truepower™
Where science delivers performance.
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
21-FEB-2012 2.1.1

United States - Annual Average Wind Speed at 80 m



Kentucky - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 16 WGS84.

AWS Truepower™ Where science delivers performance.

NREL NATIONAL RENEWABLE ENERGY LABORATORY

20-OCT-2010 1.1.1

Wind Resource

Kentucky

The wind power resource data for this map was produced by TrueWind Solutions using the Mesomap system and historical weather data. It has been validated with available surface data by the National Renewable Energy Laboratory and wind energy meteorological consultants.

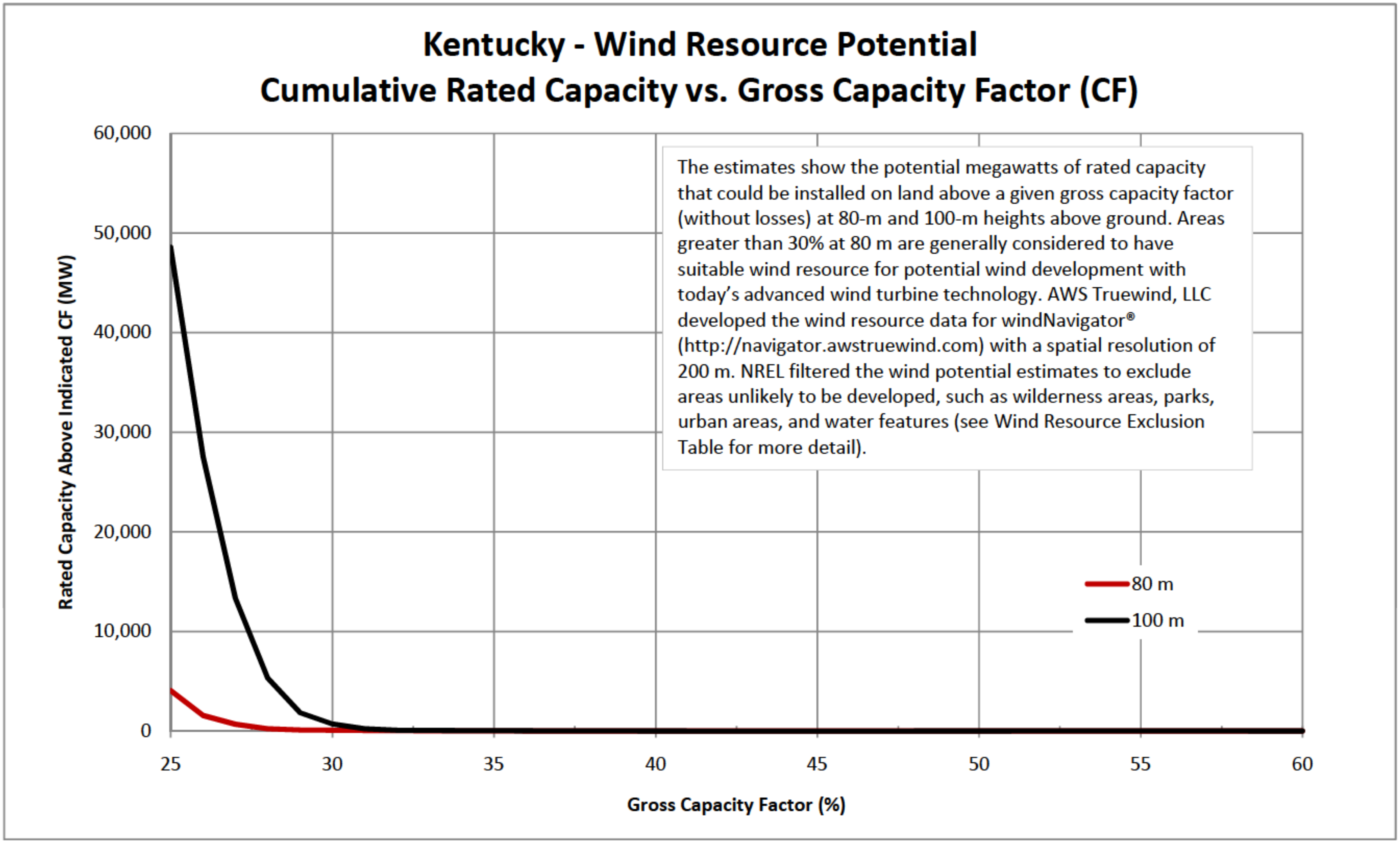
Wind Power Classification

Wind Power Class	Resouce Potential	Wind Power Density at 50m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
1	Poor	0 - 200	0.0 - 5.6	0.0 - 12.5
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	> 800	> 8.8	> 19.7

[a] Wind speeds are based on a Weibull k value of 2.0

0 35 70 140 Miles

This map was produced by
the National Renewable Energy Laboratory
for the U.S. Department of Energy.
June 2010



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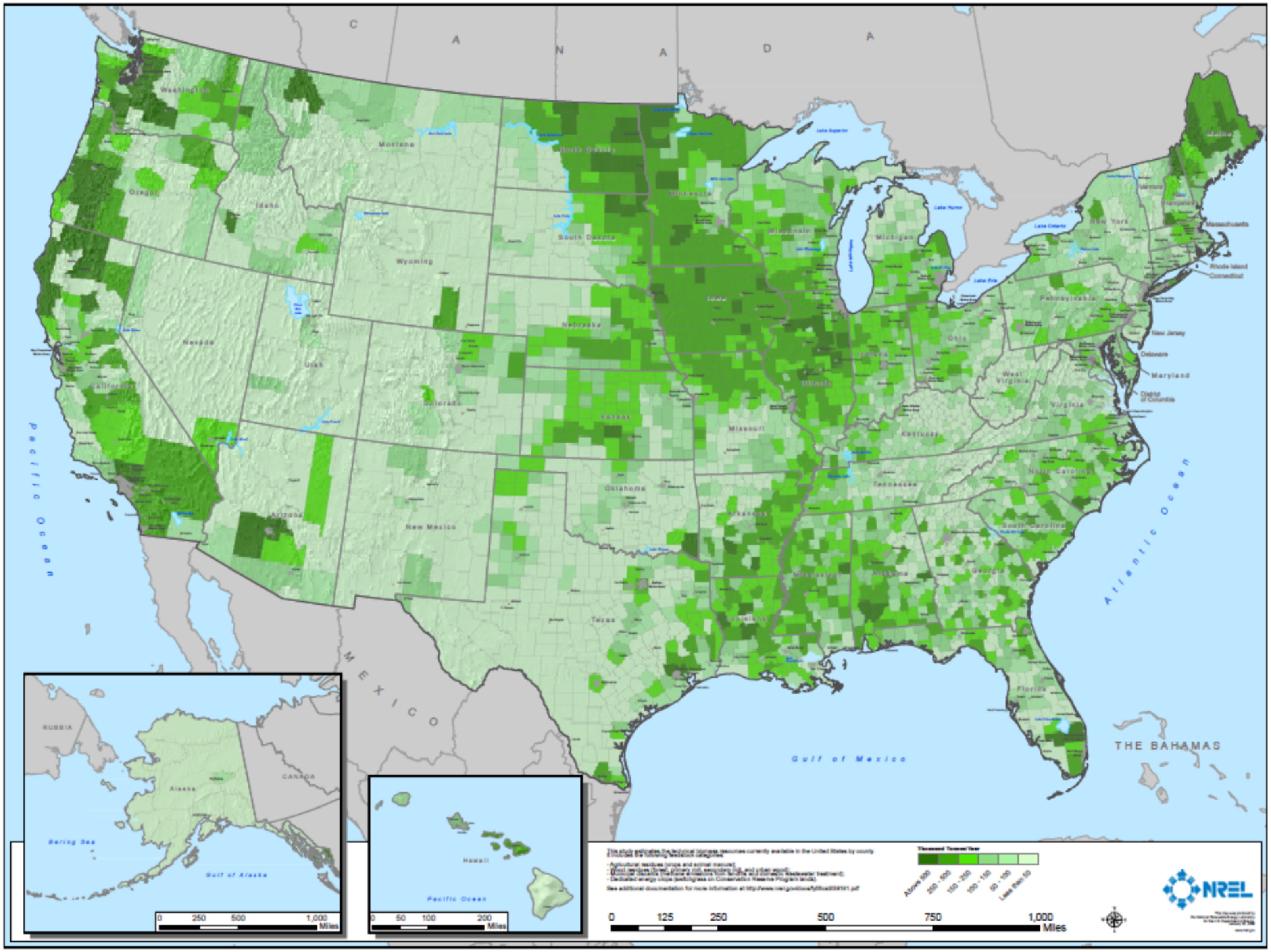
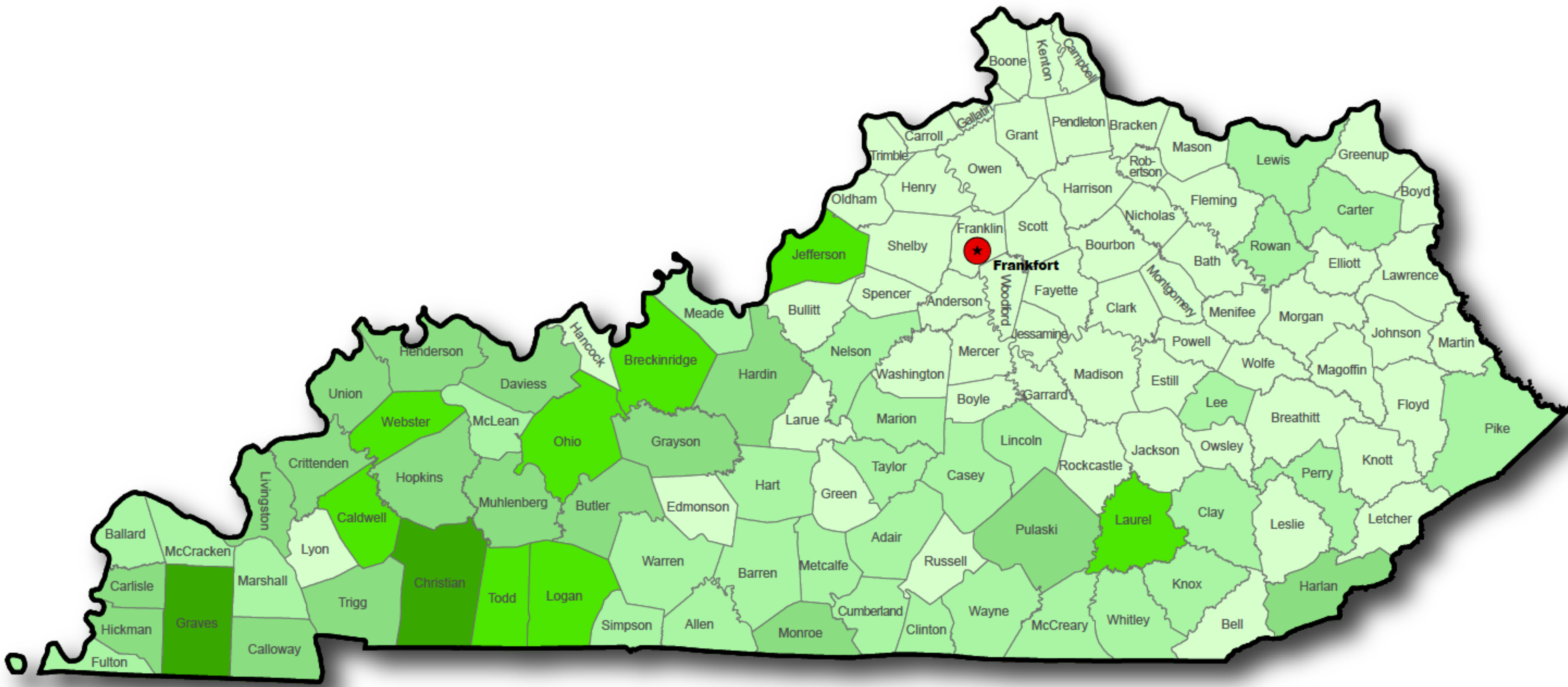
United States Biomass Resources



Biomass Resources

Kentucky



This study estimates the technical biomass resources currently available in the United States by county. It includes the following feedstock categories:
- Agricultural residues (crops and animal manure);
- Wood residues (forest, primary mill, secondary mill, and urban wood);
- Municipal discards (methane emissions from landfills and domestic wastewater treatment);
- Dedicated energy crops (switchgrass on Conservation Reserve Program lands).
See additional documentation for more information at http://www.nrel.gov/docs/fy06osti/39181.pdf

Thousand Tonnes/Year

Above 500
250 - 500
150 - 250
100 - 150
50 - 100
Less than 50

Miles
0 25 50 100

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
September 25, 2007

NREL

Appendix C

Scope Basis and Assumptions Matrix

LOUISVILLE GAS & ELECTRIC/KENTUCKY UTILITIES GENERIC UNIT ASSUMPTIONS
NATURAL GAS TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX C-1

	Natural Gas - Simple Cycle	Natural Gas - Combined Cycle	Natural Gas-Small Scale
Project Description			
Plant Size(s):	60 MW Aero - LM6000 PC SPRINT	1 x 1 x 1 CC with Option for Duct Firing "F-Class" "Advanced Class" "Emerging Advanced Class"	1 MW Microturbine
	100 MW Aero - LMS100 w/ Wet Cooling	2 x 2 x 1 CC with Option for Duct Firing "F-Class" "Advanced Class" "Emerging Advanced Class"	10 MW Fuel Cell
	100 MW Frame - "E-Class"	3 x 3 x 1 CC with Option for Duct Firing "F-Class" "Advanced Class" "Emerging Advanced Class"	
	215 MW Frame - "F-Class"		
	100 MW Spark Ignition Engine		
Fuel:	Natural Gas / Ultra Low Sulfur Fuel Oil Backup Option	Natural Gas / Ultra Low Sulfur Fuel Oil Backup Option	Natural Gas
Project Location:	Greenfield Site, Kentucky		
Contract Philosophy:	EPC with wrap on entire plant		
Project FNTP:	Q42013		
Labor Type:	Open Shop		
Site Description:	Greenfield, Clear of Trees, Reasonably Level		
Scope Basis / Assumptions			
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and stacks as applicable. No dewatering is considered.		
Site Elevation:	600 feet (Louisville).		
Site Summer Ambient Conditions:	90 F, 52% Relative Humidity		
Site Average Ambient Conditions:	59 F (ISO), 60% Relative Humidity		
Site Winter Ambient Conditions:	20 F, 60% Relative Humidity		
Water Supply:	Fresh Water supply from wells or surface water & pipeline excluded from cost (City water assumed to be available at site boundary)		
Waste Water Disposal:	Discharge offsite (NO Zero Liquid Discharge), piping facilities beyond site boundary excluded from cost		
Performance Basis			
Steam Design Pressure:	N/A	2400 Psia (Subcritical)	N/A
Steam Design Temperature:	N/A	1050 F/ 1050F	N/A
Evaporative Cooling	Included on gas turbines	Included	N/A
Heat Rejection Design:	Fin Fan Heat Exchanger for Lube Oil and auxiliary cooling	Wet Cooling Tower	N/A
Fuel, Sorbent, and Ash Landfill			
Design Fuel:	Nat Gas @ Site Bondary, ≈ 500 psig	Nat Gas @ Site Bondary, ≈ 500 psig	Nat Gas @ Site Bondary, ≈ 500 psig
Back-up Fuel:	Ultra-low Sulfur Diesel Option	Ultra-low Sulfur Diesel Option	N/A
Start-up Fuel:	Nat Gas / Oil	Nat Gas / Oil	Nat Gas
Fuel for Duct Burners:	N/A	Natural Gas Only	N/A
Fuel Oil Delivery and unloading:	Delivered by truck. Unloading station included on site.		N/A
Fuel Oil Storage:	Onsite storage, 3 day storage for SC / CC		N/A
Ammonia:	19% Aqueous Ammonia delivered by truck (as applicable)	19% Aqueous Ammonia delivered by truck	N/A
Enclosures			
Gas Turbine:	Outdoors		
Steam Turbine:	N/A	Indoors	N/A
HRSG:	N/A	Outdoors	N/A
Scrubber:	N/A	N/A	N/A
Buildings:			
Administration Building	Included		Excluded
Warehouse	Included		Excluded
Maintenance	Included		Excluded
Misc. Equipment Enclosures	Minimal Included. Limited to Electrical Equipment, CEMS enclosure, etc		
Emissions and Emissions Controls*			
NOx Control:	HOT SCR for Aero Units and "E Class", DLN for Frame Units	SCR	N/A
CO Control:	CO Catalyst for Aero Units and "E Class". Combustion Controls for Frame Units	CO Catalyst	N/A
SO_2 Control:	Low Sulfur Fuel		
SO_3 Control:	N/A		
PM10 Control (filterable & condensable particulate):	N/A		
Mercury Control:	N/A		
VOC Control:	Combustion control / good combustion practice		
CO2 Capture/Compression	N/A		
Transmission/Interconnection			
Switchyard:	Included W / Position for generators & 2 outgoing lines		
Transmission:	Excluded		
Transmission Interconnect:	Excluded. Scope of costs ends at outgoing connections in switchyard.		
Interconnection Voltage:	345 kV		
Miscellaneous Equipment			
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage		
Emergency Generator:	New Diesel Generator		
Auxiliary Boiler:	Excluded	Included	N/A
Black Start:	Excluded	Excluded	N/A
Construction Indirects			
Performance & Pre-Operational Testing	Allowance Included		
Startup Tech Service	Allowance Included		
Site Surveys/Studies	Allowance Included		
Design Engineering	Allowance Included		
Construction and Startup Management	Allowance Included		
Construction Testing	Allowance Included		
Retention Bond	Allowance Included		
Performance Bond	Allowance Included		
Freight	Allowance Included		
Escalation	Excluded		
EPC Fee & Contingency	Allowance Included		
Owner's Costs			
Project Development	Allowance Included		
Owner Operations Personnel Prior to COD	Allowance Included		
Owner's Project Management	Allowance Included		
Owner Engineering	Allowance Included		
Owner Legal Council	Allowance Included		
Operator Training	Allowance Included		
Permitting & License Fees	Allowance Included		
Land	Excluded		
Water Rights Cost	Excluded		
Site Water Supply/Discharge	Included in Owner's Costs, intake structure from Ohio River only		
Natural Gas Infrastructure	Excluded		
Initial Fuel Inventory	Excluded		
Builder's Risk Insurance	Allowance Included		
Operating Spare Parts	Allowance Included		
Permanent Plant Equipment & Furnishings	Allowance Included		
Owner's Contingency	Allowance Included at 5% for screening purposes.		
Sales Tax	Excluded		
Interest During Construction	Excluded		
Financing Fees	Excluded		
Temporary Utilities	Allowance Included		
Startup Testing Fuels and Consumables	Allowance Included		
Political Concessions/Area Development Fees	Allowance Included		
Site Security	Allowance Included		

LOUISVILLE GAS & ELECTRIC/KENTUCKY UTILITIES GENERIC UNIT ASSUMPTIONS
RENEWABLE - STORAGE -NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX C-2

	Renewables				Storage		
Project Description							
Plant Size(s):	50 MW Wind Energy	50 MW Solar Thermal	50 MW Solar PV	50 MW Low-Head Hydroelectric	200 MW Pumped Hydroelectric	10 MW Advanced Battery	135 MW Compressed Air Energy Storage (CAES)
Fuel:	N/A	N/A	N/A	N/A	N/A	N/A	Natural Gas
Project Location:	Greenfield Site, Kentucky						
Contract Philosophy:	EPC with wrap on entire plant						
Project FNTP:	Q42013						
Labor Type:	Open						
Site Description:	Greenfield, Clear of Trees, Reasonably Level						
Scope Basis / Assumptions							
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and stacks as applicable. No dewatering is considered.						
Site Elevation:	600 feet (Louisville).						
Site Summer Ambient Conditions:	90 F, 52% Relative Humidity						
Site Average Ambient Conditions:	59 F (ISO), 60% Relative Humidity						
Site Winter Ambient Conditions:	20 F, 60% Relative Humidity						
Water Supply:	Fresh Water supply from wells or surface water & pipeline excluded from cost						
Waste Water Disposal:	Discharge offsite (NO Zero Liquid Discharge), piping facilities beyond site boundary excluded from cost						
Performance Basis							
Steam Design Pressure:	N/A	1450	N/A	N/A	N/A	N/A	N/A
Steam Design Temperature:	N/A	700	N/A	N/A	N/A	N/A	N/A
Heat Rejection Design:	N/A	Cooling Tower	N/A	N/A	N/A	N/A	N/A
Enclosures							
Gas Turbine:	N/A	N/A	N/A	N/A	N/A	N/A	Outdoors
Steam Turbine:	N/A	Enclosed	N/A	N/A	N/A	N/A	N/A
Buildings:							
Administration Building	Included						
Warehouse	Included						
Maintenance	Included						
Misc. Equipment Enclosures	Minimal Included. Limited to Electrical Equipment, CEMS enclosure, etc						
Emissions and Emissions Controls*							
NOx Control:	N/A	N/A	N/A	N/A	N/A	N/A	SCR/Water Injection
CO Control:	N/A	N/A	N/A	N/A	N/A	N/A	CO Catalyst
SO_2 Control:	N/A	N/A	N/A	N/A	N/A	N/A	Low Sulfur Fuel
PM10 Control (filterable & condensable particulate):	N/A	N/A	N/A	N/A	N/A	N/A	Combustion control / good combustion practice
Mercury Control:	N/A	N/A	N/A	N/A	N/A	N/A	N/A
VOC Control:	N/A	N/A	N/A	N/A	N/A	N/A	Combustion control / good combustion practice
Transmission/Interconnection							
Switchyard:	Included W / Position for generators & 2 outgoing lines						
Transmission:	Excluded						
Transmission Interconnect:	Excluded. Scope of costs ends at outgoing connections in switchyard.						
Interconnection Voltage:	345 kV						
Miscellaneous Equipment							
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage						
Emergency Generator:	New Diesel Generator						
Auxiliary Boiler:	Excluded						
Black Start:	Excluded						
Automatic Bypass Dampers	N/A						
Construction Indirects							
Performance & Pre-Operational Testing	Allowance Included						
Startup Tech Service	Allowance Included						
Site Surveys/Studies	Allowance Included						
Design Engineering	Allowance Included						
Construction and Startup Management	Allowance Included						
Construction Testing	Allowance Included						
Retention Bond	Allowance Included						
Performance Bond	Allowance Included						
Freight	Allowance Included						
Escalation	Excluded						
EPC Fee & Contingency	Allowance Included						
Owner's Costs							
Project Development	Allowance Included						
Owner Operations Personnel Prior to COD	Allowance Included						
Owner's Project Management	Allowance Included						
Owner Engineering	Allowance Included						
Owner Legal Council	Allowance Included						
Operator Training	Allowance Included						
Permitting & License Fees	Allowance Included						
Land	Excluded						
Water Rights Cost	Excluded						
Site Water Supply/Discharge	Included in Owner's Costs, intake structure from Ohio River only (Solar Power Tower Only)						
Natural Gas Infrastructure	Excluded						
Initial Fuel Inventory	Excluded						
Builder's Risk Insurance	Allowance Included						
Operating Spare Parts	Allowance Included						
Permanent Plant Equipment & Furnishings	Allowance Included						
Owner's Contingency	Allowance Included at 5% for screening purposes.						
Sales Tax	Excluded						
Interest During Construction	Excluded						
Financing Fees	Excluded						
Temporary Utilities	Allowance Included						
Startup Testing Fuels and Consumables	Allowance Included						
Political Concessions/Area Development Fees	Allowance Included						
Site Security	Allowance Included						

LOUISVILLE GAS & ELECTRIC/KENTUCKY UTILITIES GENERIC UNIT ASSUMPTIONS
SOLID FUEL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX C-3

	Waste-to-Energy							Coal - CFB Subcritical	Coal - IGCC	Coal - PC Subcritical	Coal - PC Supercritical	Coal - PC Supercritical
Project Description												
Plant Size(s):	50 MW Stoker-Fired			5 MW IC Engine		100 MW 10% Wood Biomass Cofiring PC Boiler Retrofit	50 MW 50% Wood Biomass CFB Biomass Cofiring	2 x 250 MW With and Without Carbon Capture	2x1 IGCC 620 MW Net With and Without Carbon Capture	500 MW Net With and Without Carbon Capture	500 MW Net With and Without Carbon Capture	750 MW Net With and Without Carbon Capture
Fuel:	100% Refuse-Derived Fuel	100% Chipped Wood Biomass	100% Municipal Solid Waste	100% Anaerobic Digester Gas	100% Landfill Gas	Illinois Basin coal (up to 100%) Wood Biomass (up to 10%)	Illinois Basin coal (up to 100%) Wood Biomass (up to 100%)	100% Illinois High Sulfur Bituminous Coal				
Operation:	Base Load with outages for maintenance. Part load operation not anticipated.											
Project Location:	Greenfield Site, Kentucky											
Contract Philosophy:	EPC with wrap on entire plant											
Project FNTP:	Q42013											
Labor Type:	Open											
Site Description:	Greenfield, Clear of Trees, Reasonably Level. No existing structures or underground ut lities.											
Scope Basis / Assumptions												
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and stacks as applicable. No dewatering is considered											
Site Elevation:	600 feet (Louisville)											
Site Summer Ambient Conditions:	90 F, 52% Relative Humidity											
Site Average Ambient Conditions:	59 F (ISO), 60% Relative Humidity											
Site Winter Ambient Conditions:	20 F, 60% Relative Humidity											
Water Supply:	Excluded from EPC Cost (Included in Owners)											
Waste Water Disposal:	Discharge offsite (NO Zero Liquid Discharge), piping facilities beyond site boundary excluded from cost											
Performance Basis												
Steam Design Pressure:	1400 psia			N/A		2535 psia		2535 Psia (Subcritical)			3675 Psia (Super Critical)	
Steam Design Temperature:	950 F / 950 F			N/A		1050 F / 1050 F		1050 F/ 1050F				
Evaporative Cooling	N/A			Not Included		N/A		N/A	Included	N/A	N/A	
Heat Rejection Design:	Wet Cooling Tower			Fin Fan Heat Exchanger for Lube Oil and auxiliary cooling		Wet Cooling Tower		Wet Cooling Tower				
Fuel, Sorbent, and Ash Landfill												
Design Fuel:	100% Refuse-Derived Fuel	100% Chipped Wood Biomass	100% Municipal Solid Waste	Anaerobic Digester Gas	Landfill Gas	Illinois Basin coal (up to 100%) Wood Biomass (up to 10%)	Illinois Basin coal (up to 100%) Wood Biomass (up to 100%)	100% Illinois High Sulfur Bituminous Coal	100% Illinois High Sulfur Bituminous Coal	100% Illinois High Sulfur Bituminous Coal	100% Illinois High Sulfur Bituminous Coal	100% Illinois High Sulfur Bituminous Coal
Back-up Fuel:	N/A											
Start-up Fuel:	Natural Gas			Same as Primary		Natural Gas		Natural Gas				
Fuel Blending:	None			N/A		Up to 10% wood biomass	Up to 100% of design fuel blend	None Included				
Fuel Handling System	Assumes pre-processed			Anaerobic Digester	Landfill collector well							
Unloading System:	Truck			N/A		Truck		New rail unloading system utilizing rotary dumper rail cars and barge unloading				
Live Storage:	Covered pile storage			N/A		Open, uncovered pile storage		Open uncoverd pile storage				
Long-term coal storage:	Dead outdoor, open pile storage			N/A		Dead outdoor, open pile storage		Dead outdoor, open pile storage using mobile equipment				
Fuel Oil Delivery and unloading:	N/A											
Fuel Oil Storage:	N/A											
SO_2 Control Reagent:	Dry Sorbent Injection			None Included		Dry Sorbent Injection, Polishing FGD		Limestone / Lime in Polishing Scrubber	Selexol Solution (Not Consumed)	Limestone	Limestone	Limestone
SO_2 Control Reagent Delivery:	Truck (as applicable)											
SO_2 Control Reagent Storage:	Truck (as applicable)											
Ammonia:	19% Aqueous Ammonia, Delivered By Truck											
Mercury Sorbent Storage:	Silo			N/A		Silo		Silo	Disposable Media Bed	Silo		
Fly Ash Disposal:	Onsite Landfill			N/A		N/A		Onsite Landfill	N/A	Onsite Landfill		
Scrubber Sludge / Byproduct Disposal:	None			N/A		N/A		Included in Fly ash	Onsite Landfill	Onsite Landfill (No Gypsum Sales)		
Bottom Ash Disposal:	Onsite Landfill			N/A		N/A		Onsite Landfill	Onsite Landfill	Onsite Landfill		
Landfill delivery:	Truck											
Enclosures												
Engine/Gas Turbine:	N/A			Indoors		N/A		N/A	Outdoors	N/A		
Steam Turbine:	Indoors			N/A		Indoors		Indoors				
Boiler:	Enclosed			N/A		Enclosed		Enclosed	N/A	Enclosed		
Scrubber:	N/A			N/A		Outdoors		Outdoors	N/A	Outdoors		
Buildings:												
Administration Building	Included											
Warehouse	Included											
Maintenance	Included											
Misc. Equipment Enclosures	Minimal Included. Limited to Electrical Equipment, CEMS enclosure, etc											

LOUISVILLE GAS & ELECTRIC/KENTUCKY UTILITIES GENERIC UNIT ASSUMPTIONS
SOLID FUEL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
APPENDIX C-3

	Waste-to-Energy				Coal - CFB Subcritical	Coal - IGCC	Coal - PC Subcritical	Coal - PC Supercritical	Coal - PC Supercritical
Project Description									
Plant Size(s):	50 MW Stoker-Fired	5 MW IC Engine	100 MW 10% Wood Biomass Cofiring PC Boiler Retrofit	50 MW 50% Wood Biomass CFB Biomass Cofiring	2 x 250 MW With and Without Carbon Capture	2x1 IGCC 620 MW Net With and Without Carbon Capture	500 MW Net With and Without Carbon Capture	500 MW Net With and Without Carbon Capture	750 MW Net With and Without Carbon Capture
Emissions and Emissions Controls*									
NOx Control:	SNCR	SCR	SCR	SNCR	SNCR	Nitrogen Injection/SCR	SCR	SCR	SCR
CO Control:	Good Combustion Practice								
SO_2 Control:	Dry Sorbent Injection	None Included	Wet FGD	Dry Sorbent Injection+Limestone Bed	Limestone & Flyash injection + Polishing Scrubber	Selexol Scrubber	Wet Limestone Forced Oxidation Scrubber		
PM10 Control (filterable & condensable particulate):	Fabric Filter Baghouse	Good Combustion Practices	Fabric Filter Baghouse		Fabric Filter Baghouse	N/A	Fabric Filter Baghouse		
Mercury Control:	Dry Sorbent Injection	None Included	Dry Sorbent Injection		Dry Sorbent Injection	Carbon Bed Filter	Dry Sorbent Injection		
VOC Control:	Good Combustion Practice								
CO2 Capture/Compression/Transport	N/A	N/A	N/A		Advanced Amine Carbon Capture System	Selexol Scrubber	Advanced Amine Carbon Capture System		
Transmission/Interconnection									
Switchyard:	Included W / Position for generators & 2 outgoing lines (1 additional space for startup power included for coal plants (including IGCC) only)								
Transmission:	Excluded								
Transmission Interconnect:	Excluded. Scope of costs ends at outgoing connections in switchyard.								
Interconnection Voltage:	345 kV								
Coal Reciept									
Receiving System:	N/A	N/A	rail w/ on-site loop track Received by Barge		Rail w/ on-site loop track received by Barge				
Rail Siding to Site:	Excluded								
Miscellaneous Equipment									
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage								
Emergency Generator:	New Diesel Generator								
Auxliary Boiler:	Included								
Black Start:	Excluded								
Construction Indirects									
Performance & Pre-Operational Testing	Allowance Included								
Startup Tech Service	Allowance Included								
Site Surveys/Studies	Allowance Included								
Design Engineering	Allowance Included								
Construction and Startup Management	Allowance Included								
Construction Testing	Allowance Included								
Retention Bond	Allowance Included								
Performance Bond	Allowance Included								
Freight	Allowance Included								
Escalation	Excluded								
EPC Fee & Contingency	Allowance Included								
Owner's Costs									
Project Development	Allowance Included								
Owner Operations Personnel Prior to COD	Allowance Included								
Owner's Project Management	Allowance Included								
Owner Engineering	Allowance Included								
Owner Legal Council	Allowance Included								
Operator Training	Allowance Included								
Permitting & License Fees	Allowance Included								
Land	Excluded								
Water Rights Cost	Excluded								
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Natural Gas Infrastructure	Excluded								
Initial Fuel Inventory	Excluded								
Builder's Risk Insurance	Allowance Included								
Operating Spare Parts	Allowance Included								
Permanent Plant Equipment & Furnishings	Allowance Included								
Owner's Contingency	Allowance Included at 5% for screening purposes								
Sales Tax	Excluded								
Interest During Construction	Excluded								
Financing Fees	Excluded								
Temporary Utilities	Allowance Included								
Startup Testing Fuels and Consumables	Allowance Included								
Political Concessions/Area Development Fees	Allowance Included								
Site Security	Allowance Included								

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 24

Witness: David E. Huff

Q-24. Refer to the IRP, page 8-49 and 8-50, regarding DSM resource screening and assessment. Explain the process and procedures utilized by the Companies to retain the Cadmus Group for the market potential study and DSM Program Review.

A-24 The Companies utilized and adhered to their standard operating procedure in issuing a request for proposal ("RFP") for a market potential study and DSM Program Review. The RFP was issued on May 25, 2012 to ten potential vendors. The Companies received four proposals that were scored based on pricing, evaluation process, reporting, experience, and references. Based on the results of the scoring matrix, Cadmus was awarded a contract.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 25

Witness: David E. Huff

Q-25. Refer to the IRP, page 8-64, which states, "The only reason for the Companies to acquire new supply-side or demand-side resources is to reliably meet customers' future energy needs at the lowest reasonable cost." Provide what demand-side resources the Companies acquired as of the 2011 IRP and since the 2011 IRP, and what demand-side resources might be acquired in the future.

A-25 Since the 2011 IRP, the Companies have submitted and gained approval for their DSM plans in Case Nos. 2011-00134 and 2014-00003. These filings included: Residential and Commercial Load Management; Commercial Conservation; Residential Conservation; Residential Low Income Weatherization Program; Smart Energy Profile Program; Residential Incentives Program; and a Residential Refrigerator Removal Program and Program Development and Administration.

Since the 2011 IRP, the Companies realized an incremental demand reduction of 42 MW in 2011; 46 MW in 2012; and 67 MW in 2013. The Companies will be adding an additional demand reduction of a projected 201 MW demand savings. Upon completion of the 2014-00003 program plan, the DSM/EE Program Plan will produce overall energy and demand savings for the Companies, bringing the total cumulative demand savings created by the Companies' DSM/EE portfolio to 500 MW by the end of 2018.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 26

Witness: Charles R. Schram

Q-26. Refer to the last page of the Technical Appendix — Volume II, KU, LG&E, & ODP Commercial Forecast Models. The last sentence indicates that elasticities of demand were created based on a discussion with Itron and research by LG&E and KU.

a. Provide a general description of how elasticities of demand have been factored into LG&E's and KU's forecasts.

b. Provide the measures of the elasticities of demand reflected in the forecasts for the different customer sectors, both short-term and long-term measures.

A-26

a. The price elasticity of demand and price are inputs to the residential and commercial Statistically Adjusted End-use (SAE) models described in the Technical Appendix – Volume II. As such, the forecasted sales quantities are impacted by the change in the price series. Specifically, as the forecasted price increases, the forecasted demand declines.

b. The price elasticity of demand inputs used in the 2014 IRP forecast are -0.1 for residential customers and -0.05 for commercial customers. There is not a distinction in the model between short-term and long-term price elasticities of demand.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 27

Witness: Charles R. Schram

Q-27 Refer to the IRP, Volume III, 2014 Reserve Margin Study, Generation and Planning Analysis, Section 2, page 6. The Companies state that on August 4, 2010, they purchased 800 MW of power to meet internal demand.

a. Did the Companies have reserve sharing contracts with neighboring utilities in place at the time?

b. What is the current and proposed future status of the Companies Reserve Sharing agreements?

A-27

a. Yes. However, the Companies can call upon reserve-sharing resources for only short periods of time (up to 105 minutes) to respond to immediate resource contingencies or other conditions that could potentially result in shedding firm load.

b. The Companies are currently in a reserve sharing agreement with TVA and carry 258 MW of reserves as their share of the parties' largest single contingency. The Companies do not have plans to alter this agreement.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Request for Information
Dated November 7, 2014

Case No. 2014-00131

Question No. 28

Witness: Charles R. Schram

Q-28 Refer to the 2014 Resource Assessment Addendum, page 5. The Companies note the need for long-term capacity in 2020. Explain whether the currently withdrawn 700-MW Green River NGCC will remain a viable supply-side source option to fill this capacity need.

A-28 An NGCC unit at Green River is a potential supply-side option to meet the Companies' forecasted long-term capacity need beginning in 2020. Consistent with prior proposals for new generation, the Companies will review capacity and energy needs along with potential sites, technologies, unit capacity, and configuration before finalizing any plans for new generation.