COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Company To Convert Big Sandy Unit 1 To A Natural Gas-Fired Unit; And (2) For All Other Required Approvals And Relief	)))	Case No. 2013-000-___

APPLICATION

Kentucky Power Company ("Kentucky Power" or the "Company") moves the Public Service Commission of Kentucky ("Commission") for an Order: (1) granting the Company a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5:001, Section 15 to convert the Company's existing Big Sandy Unit 1 from a coal-fired facility to a natural gas-fired unit; and (2) granting all other required relief or approvals. In support thereof Kentucky Power states:

INTRODUCTION

1. As of the date of this application, the Company's owned generating resources consist of the 278 MW coal-fired Big Sandy Unit 1 and the 800 MW coal-fired Big Sandy Unit 2.[1] The 2012 Mercury and Air Toxics Standard ("MATS") will make the current environmental

[1] By order dated October 7, 2013 in Case No. 2012-00578, *In the Matter of: The Application of Kentucky Power Company For: (1) A Certificate of Public Convenience And Necessity Authorizing The Transfer To the Company Of A Fifty Percent Undivided Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief*, (Ky. P.S.C. Filed December 19, 2012), the Commission approved the July 2, 2013 Stipulation and Settlement Agreement among Kentucky Power Company, Kentucky Industrial Utility Customers, Inc., and the Sierra Club, with four modifications accepted by the Company, and granted the authorizations necessary to transfer

controls on Big Sandy Unit 1 insufficient to meet the applicable environmental standards. Absent an administrative extension, Big Sandy Unit 1 will no longer be able to operate as currently configured beginning May 2015.[2]

2. The Company has determined that converting Big Sandy Unit 1 from a coal-fired to a natural gas-fired unit is a least cost alternative for addressing the applicable environmental standards affecting the continued operation of Big Sandy Unit 1.

APPLICANT

3. Kentucky Power was organized in 1919 under the laws of the Commonwealth of Kentucky.[3] The Company's mailing address is 101A Enterprise Drive, P.O. Box 5190, Frankfort, Kentucky 40602-5190. Its electronic mail address is jkrosquist@aep.com. Kentucky Power is engaged in the generation, purchase, transmission, distribution and sale of electric power. The Company serves approximately 173,000 retail customers in the following 20 counties of eastern Kentucky: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike and Rowan. In addition, the Company also supplies electric power at wholesale to other utilities and municipalities in Kentucky

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the 50% undivided interest in the Mitchell Generating Station to Kentucky Power. The purpose of the transfer of the 50% undivided interest in the Mitchell Generating Station to Kentucky Power is to replace the generation loss resulting from the forced retirement of Big Sandy Unit 2.

[2] Although the MATS Rule implementation date is April 16, 2015, it is expected, after consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of MATS, that the AEP-East unit – including Big Sandy Units 1 and 2 – being planned for retirement will be able to operate without administrative extension through the full PJM 2014/15 capacity "planning year" (*i.e.*, through May 31, 2015).

[3] A certified copy of the Company's Articles of Incorporation and all amendments thereto was attached to the Joint Application in *In the Matter Of: The Joint Application Of Kentucky Power Company, American Electric Power Company, Inc. And Central And South West Corporation Regarding A Proposed Merger*, P.S.C. Case No. 99-149. The December 4, 2013 Kentucky Power "Certificate of Existence" issued by the Secretary of State of the Commonwealth of Kentucky is filed as Exhibit 1 to this Application.

for resale. Kentucky Power is a utility as that term is defined at KRS 278.010. [807 KAR 5:005, Section 14].

4. Kentucky Power is a direct, wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP.") AEP is a multi-state public utility holding company whose operating companies provide electric utility service to customers in parts of eleven states – Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

BACKGROUND

The Proposed Conversion Project

5. Big Sandy Unit 1 is 278 MW (net summer rating) coal-fired subcritical generating unit located in Lawrence County, Kentucky. Big Sandy Unit 1 was commissioned in 1963.

A. The Need For The Conversion.

6. On February 16, 2012, the United States Environmental Protection Agency published the Mercury MATS Rule in the federal register. The MATS Rule includes stringent emission limits for mercury, particulate matter as well as hydrochloric acid or sulfur dioxide. To comply with the MATS limits, Kentucky Power must install additional, costly emission control equipment at Big Sandy Unit 1 (in the form of flue gas desulfurization and selective catalytic reduction technology), switch fuels, or retire the unit. The costs of retrofitting Big Sandy Unit 1 with the additional emission control equipment required to permit it to continue to operate as a coal-fired unit far exceeds the alternatives modeled by the Company for replacing that coal-fired generation.

7. The initial MATS compliance date is April 16, 2015. A one-year administrative extension of the initial compliance date may be granted by a state's air quality agency for units undertaking major retrofit or replacement projects, or for units that will retire but are required for reliability purposes. Because of the time required to convert Big Sandy Unit 1 to natural gas, the Company anticipates seeking the one-year administrative extension.

B. The Proposed Modifications To Big Sandy Unit 1.

8. The proposed conversion of Big Sandy Unit 1 to natural gas will require modifications to the existing steam generator and unit control systems, the installation of new natural gas metering and regulating facilities, and modifications to certain associated plant systems. Additional detail concerning the anticipated modifications to Big Sandy Unit 1 is provided in the testimony of Company Witness Robert L. Walton.

9. Much of the plant infrastructure, including the plant buildings and structures, steam turbines and electrical generator, electrical distribution systems, condensate and feedwater systems, and wastewater processing equipment, can continue to be used following the conversion of Big Sandy Unit 1 to a natural gas-fired unit.

10. With its conversion to a gas-fired unit, Big Sandy Unit 1 is expected to experience a reduction from its current 278 MW (net summer rating) to an expected 268 MW (net summer rating) output capability, along with a slight increase in its current heat rate.

11. The total estimated capital cost of the Big Sandy Unit 1 conversion, excluding AFUDC and the cost of the gas transport lateral described below, is estimated to be approximately $50 million.

12. The Company estimates that the conversion project, including the construction of the gas transport lateral, can be completed, and Big Sandy Unit 1 can begin operation as a gas-fired unit, by mid-May 2016.

13. Kentucky Power intends to request a one-year administrative extension of the 2015 MATS compliance deadline to accommodate the projected mid-May 2016 completion of the conversion project.

C. The Natural Gas Supply And Transportation.

14. To fuel Big Sandy Unit 1 following its conversion Kentucky Power will purchase natural gas from gas suppliers and producers. Because of the need for flexibility, and consistent with the practice employed by the Company's affiliates with respect to similar units, Kentucky Power intends to rely predominantly on daily spot market gas purchases.

15. Because the Company lacks facilities for delivery of natural gas to Big Sandy Unit 1 it will be required to contract with a natural gas pipeline company for the construction of a natural gas supply lateral.

16. Kentucky Power, in collaboration with American Electric Power Service Corporation's ("AEPSC") Engineering Services, Project, Controls & Construction, and Fuel, Emissions & Logistics groups, have identified gas quality and delivery requirements for the converted Big Sandy Unit 1. In addition, AEPSC Fuel, Emissions & Logistics contacted Federal Energy Regulatory Commission-regulated natural gas pipeline companies to obtain indicative capital cost estimates and installation schedules for the project.

17. Kentucky Power senior management, in collaboration with AEPSC's Fuel, Emissions & Logistics group, will continue to evaluate the natural gas supply proposals. The Company will select the least-cost transporter that best meets the Company's specifications and vendor risk and credit qualifications, and demonstrates the ability to provide reliable long-term natural gas transportation.

18. The gas transporter will be responsible for the construction of the natural gas supply lateral, including all related regulatory filings and right-of-way permitting.

19. Kentucky Power will construct an approximate 800 foot gas delivery pipeline from the termination point of the transporter's pipeline to the Big Sandy Unit 1 boiler building, along with a fuel gas check metering station, heater, and pressure reduction station. The cost of this gas delivery pipeline and ancillary facilities is included in the estimated cost of the project cost provided in Paragraph 11 above.

20. The Company anticipates that both the natural gas supply lateral to be constructed by the natural gas transporter and the gas delivery pipeline and facilities to be constructed by Kentucky Power will be in service by mid-May 2016.

The Request For Proposals And Economic Modeling

A. The March 28, 2013 Request For Proposals.

21. On March 28, 2013, Kentucky Power issued a Request For Proposals ("RFP") for up to 250 MW (nameplate) of long-term capacity and energy. A copy of the RFP is attached as **EXHIBIT 2** to this Application. The stated purpose of the Big Sandy Unit 1 RFP was to use the conforming proposals received in response to the RFP, "along with the BS1 Conversion cost

estimate to determine the least, reasonable cost solution to replacing the Big Sandy Unit 1 capacity as a coal fired generating unit."[4] The Big Sandy Unit 1 RFP is described in detail in the testimony of Company Witness Joseph A. Karrasch.

22. The Big Sandy Unit 1 RFP sought proposals for up to 250 MW of capacity, energy, and ancillary services (if available).[5] The generation resources bid into the Big Sandy Unit 1 RFP were required to be a PJM Generation Resources and must have been capable of being on line by June 1, 2015.[6] Generation resources bid into the proposal could be in the form of a power purchase agreement, a tolling agreement, an asset purchase agreement, or other proposal as defined in the RFP. In addition, the RFP solicited proposals for demand-side management and cost-effective energy efficiency resources.[7] All responses to the RFP were required to be received by June 11, 2013.[8]

23. The Company received both conforming and non-conforming responses to the RFP on or before June 11, 2013. Kentucky Power contacted non-conforming bidders in an effort to resolve the deficiencies, but in each instance the non-conforming bidders were unable to resolve the deficiencies.

24. In conformity with the July 2, 2013 Stipulation and Settlement Agreement among Kentucky Power, Kentucky Industrial Utility Customers, Inc. and Sierra Club in Case No. 2012-

[4] American Electric Power Service Corporation, as Agent For Kentucky Power Company, 250 MW Request For Proposals at 3 (Issued March 28, 2013) ("Big Sandy Unit 1 RFP").

[5] *Id.*

[6] *Id.*

[7] *Id.*

[8] *Id.* at 9.

00578,[9] ("Stipulation") described below, Kentucky Power on November 19, 2013 exercised its option to terminate the Big Sandy Unit 1 RFP.

25. The conforming Big Sandy Unit 1 RFP responses provide an indicative benchmark for the pricing and availability of alternatives to the Big Sandy Unit 1 conversion.

B. <u>The Economic Modeling And Non-Economic Considerations</u>.

26. To determine the relative least cost alternative for the disposition of Big Sandy Unit 1 the Company employed for this proceeding, as it did in Case No. 2011-00401 and Case No. 2012-00578, Strategist,® as a long-term resource optimization tool. Strategist® is a proprietary, highly sophisticated and industry-wide accepted economic modeling application, and has been employed by other utilities in proceedings before this Commission.[10] Additional detail concerning the Strategist® modeling and results is provided in the testimony of Company Witness Scott C. Weaver.

27. Kentucky Power used Strategist® to model the two reasonable alternatives to the conversion of Big Sandy Unit 1: (a) the retirement of Big Sandy Unit 1 in June 2015 and its

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[9] *In the Matter of: The Application of Kentucky Power Company For: (1) A Certificate of Public Convenience And Necessity Authorizing The Transfer To the Company Of A Fifty Percent Undivided Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief*, Case No. 2012-00578 (Ky. P.S.C. Filed December 19, 2012).

[10] *See e.g., In The Matter Of: Application Of Louisville Gas And Electric Company To Modify Its Certificate Of Public Convenience And Necessity As To The Mill Creek Unit 3 Flue-Gas Desulfurization Unit*, Case No. 2012-00469; *In The Matter Of: The Application Of Louisville Gas And Electric Company For Certificates Of Public Convenience And Necessity And Approval Of Its 2011 Compliance Plan For Recovery By Environmental Surcharge*, Case No. 2011-00162; *In The Matter Of: The Application Of Kentucky Utilities Company For Certificates Of Public Convenience And Necessity And Approval Of Its 2011 Compliance Plan For Recovery By Environmental Surcharge*, Case No. 2011-00161; *In The Matter Of: Application Of Kentucky Utilities Company For Certificates Of Public Convenience And Necessity And Approval Of Its 2009 Compliance Plan For Recovery By Environmental Surcharge*, Case No. 2009-00197.

replacement with PJM market purchases; (b) the retirement of Big Sandy Unit 1 in June 2015 and its replacement with the lowest cost conforming response to the Big Sandy Unit 1 RFP.

28. The Strategist® modeling indicated that the conversion of Big Sandy Unit 1 to natural gas, as well as the retirement of Big Sandy Unit 1 in June 2015 and its replacement with the lowest cost response to the Big Sandy Unit 1 RFP, were least cost alternatives. Although the replacement of Big Sandy Unit 1 with the lowest cost response to the Big Sandy 1 RFP was, on a 28-year cumulative present worth basis, slightly less than the conversion of Big Sandy Unit 1 to natural gas, the difference was within the "margin of error" of the modeling and thus is not material.

29. The conversion of Big Sandy Unit 1 to natural gas, unlike the adoption of the lowest cost response to the Big Sandy Unit 1 RFP, would eliminate counterparty and unit condition risks that would be present in a market alternative selected from the Big Sandy Unit 1 RFP. Further, the Commission will enjoy greater authority over the operation of a Kentucky Power-owned unit than with respect to a market purchase. In addition, the conversion of Big Sandy Unit 1 will permit the Company to retain a portion of its Big Sandy Plant workforce. Finally, by not retiring Big Sandy Unit 1 the Company will continue to pay *ad valorem* taxes to the Commonwealth and Lawrence County on the converted unit.

The Stipulation And Settlement Agreement

30. By Order dated October 7, 2013 the Commission approved, subject to four modifications accepted by the Company, the July 2, 2013 Stipulation and Settlement Agreement

among Kentucky Power, Kentucky Industrial Utility Customers, Inc. and Sierra Club in Case No. 2012-00578.[11]

31. Paragraph 13 of the July 2, 2013 Stipulation and Settlement Agreement provides:

> 13. The Company shall file with the Commission an application pursuant to KRS 278.020 for Certificate of Public Convenience of Necessity to convert the 268 MW Big Sandy Unit 1 to natural gas, and will exercise its option to terminate its March 28, 2013 Request for Proposals. All parties to this Settlement Agreement agree they will not move to intervene to challenge the Company's filing for the required Certificate of Public Convenience and Necessity to convert Big Sandy Unit 1 to natural gas, provided the cost to convert is approximately $60 million.

32. This application is in conformity with, and satisfaction of, paragraph 13 of the July 2, 2013 Stipulation and Settlement Agreement.

THE PUBLIC CONVENIENCE AND NECESSITY MANDATE THE CONVERSION OF BIG SANDY UNIT 1 TO A NATURAL GAS-FIRED UNIT

33. A utility seeking a certificate of public convenience and necessity must "demonstrate a need for … [the proposed] facilities and the absence of wasteful duplication."[12] Need in turn requires a demonstration:

> of a substantial inadequacy of existing service, involving a

[11] *In the Matter of: The Application of Kentucky Power Company For: (1) A Certificate of Public Convenience And Necessity Authorizing The Transfer To the Company Of A Fifty Percent Undivided Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief*, (Ky. P.S.C. Filed December 19, 2012).

[12] *In The Matter Of: Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity And Site Compatibility Certificate For The Construction Of A Combined Cycle Combustion Turbine At The Cane Run Generation Station And The Purchase Of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC In LaGrange, Kentucky*, Case No. 2011-00375 at 13-14 (Ky. P.S.C. May 3, 2012).

> consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[13]

34. The Big Sandy Unit 1 conversion is required to permit Kentucky Power to meet its long-term capacity obligations and to provide generation to meet its customers' energy requirements. The conversion of Big Sandy Unit 1 to a natural gas-fired unit is a least cost alternative for meeting these obligations and requirements.

35. The proposed conversion will not result in wasteful duplication. "'Wasteful duplication' is defined as 'an excess of capacity over need' and 'an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties.'"[14] Kentucky Power performed a thorough review of reasonable alternatives to meet its capacity and energy requirements, including energy efficiency resources, and determined the conversion of Big Sandy Unit 1 is a least cost, reasonable alternative for meeting the Company's capacity and energy requirements.

REGULATORY REQUIREMENTS – 807 KAR 5:001, SECTION 15

36. The facts demonstrating that the conversion of Big Sandy Unit 1 from a coal-fired unit to a natural gas-fired unit is required by the public convenience or necessity are set forth above. [807 KAR 5:001, Section 15(2)(a)].

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[13] *Id.* at 14.

[14] *Id.*

37. Kentucky Power will submit requests to modify existing Title V permits, and other permits and licenses to reflect the conversion of Big Sandy Unit 1 to a natural gas-fired unit, and for a one year-administrative extension of the MATS compliance deadline. The Company is not required to seek any franchises in connection with the transfer of the Transferred Assets and hence 807 KAR 5:001, Section 15(2)(b) is inapplicable. [807 KAR 5:001, Section 15(2)(b)].

38. Big Sandy Unit 1 is located at 23000 Highway 23 North, Louisa, KY 41230. The proposed construction will take place in and around the existing Big Sandy facility. The location and route of the proposed natural gas lateral pipeline will not be known until an agreement for natural gas transportation service is executed. It is anticipated the natural gas lateral pipeline will terminate approximately 800 feet from the Big Sandy Unit 1 boiler. The gas delivery pipeline to be constructed by Kentucky Power will run between the termination point of the natural gas lateral pipeline and the Big Sandy Unit 1 boiler. [807 KAR 5:001, Section 15(2)(c)].

39. It is not anticipated that the proposed conversion will compete with any other utility, corporation or person as described in the regulation. [807 KAR 5:001, Section 15(2)(c)].

40. Maps to suitable scale showing the location of the converted Big Sandy Unit 1, as well as the location and ownership of like facilities in the area displayed on the maps are attached as **EXHIBIT 3** (paper copy) and **EXHIBIT 4** (electronic copy) to this Application. [807 KAR 5:001, Section 15(2)(d)].

41. The proposed conversion, included the natural gas delivery pipeline, will be financed through Kentucky Power's internally generated funds. [807 KAR 5:001, Section 15(2)(e).]

42. The estimated annual operation and maintenance cost for the converted Big Sandy Unit 1 after the converted facility is placed into service as proposed in this Application is $4,684,000. [807 KAR 5:001, Section 15(2)(f).]

43. Other information necessary to afford the Commission a complete understanding of the proposed conversion is set forth above and in the exhibits and testimony filed with this application. [807 KAR 5:001, Section 15(2)(g).]

Exhibits And Testimony

44. The exhibits and testimony listed in the Appendix to this Application are attached to and made a part of this Application.

Communications

45. The Applicant respectfully requests that communications in this matter be addressed to:

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Ranie K. Wohnhas
Kentucky Power Company
P.O. Box 5190
Frankfort, Kentucky 40602-5190

ON BEHALF OF KENTUCKY POWER

WHEREFORE, Kentucky Power Company requests that the Commission issue an Order:

(a) Granting Kentucky Power a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5:001, Section 15 approving the conversion of Big Sandy Unit 1 from a coal-fired generating unit to a natural gas-fired generating unit; and

(b) Granting Kentucky Power such other relief or approvals as may be appropriate or required.

Respectfully submitted,

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COUNSEL FOR:
KENTUCKY POWER COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing was served as indicated below upon:

Michael L. Kurtz
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

By Overnight Delivery

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Kentucky Attorney General's Office
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204

By Overnight Delivery

Shannon Fisk
Earthjustice
1617 JFK Boulevard, Suite 1675
Philadelphia, PA 19103

By Overnight Delivery

on this the 6th day of December, 2013.

Mark R. Overstreet

APPENDIX

Testimony

Joseph A. Karrasch	Describes the Company's March 28, 2013 RFP for 250 MW of capacity and energy, the conforming and non-confirming responses thereto, and the risks associated with market purchase alternatives.
Robert L. Walton	Provides a summary of the planned natural gas conversion, the project schedule, and development of the project cost estimate.
Scott C. Weaver	Describes the Big Sandy Unit 1 disposition alternatives modeled, the modeling process used, and the resulting analyses.
Ranie K. Wohnhas	Provides overview of application, describes emerging environmental requirements and the manner in which the proposed project satisfies the requirements of the July 2, 2013 Stipulation And Settlement Agreement in Case No. 2012-00578, and provides an estimate of the customer rate impact of the proposed conversion.

List of Exhibits

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
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Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 145674
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

KENTUCKY POWER COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 21, 1919 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 4th day of December, 2013, in the 222nd year of the Commonwealth.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
145674/0028317

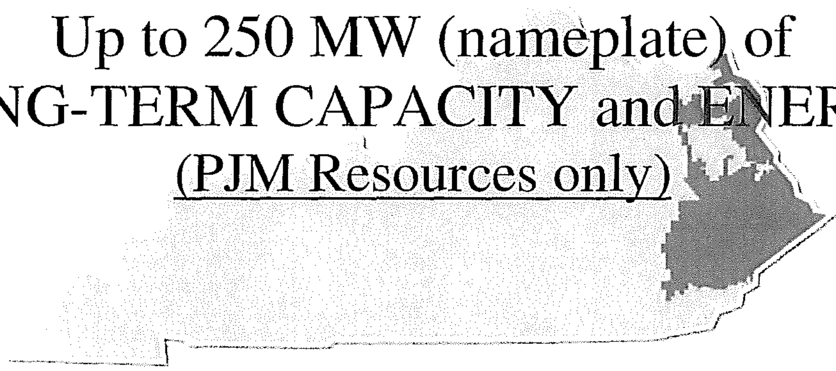
American Electric Power Service Corporation

as agent for

Kentucky Power Company

Request for Proposals

Up to 250 MW (nameplate) of
LONG-TERM CAPACITY and ENERGY
(PJM Resources only)



Capable of being on-line by June 1, 2015

Issued:
March 28, 2013

Web Address: http://www.kentuckypower.com/go/rfp/

Proposals Due:
June 11, 2013 (Columbus, OH)

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Appendices

Background

Kentucky Power Company (Company) is undertaking a process to determine the least, reasonable cost solution to replacing the impending generation loss anticipated with the retirement of its Big Sandy Unit 1 generation unit. Big Sandy Unit 1 is a 260 MW coal fired generating unit that went into service in 1963 and is currently scheduled for retirement in 2015. Big Sandy Unit 1 is located near Louisa, Kentucky and is within the PJM regional transmission organization.

The options available to the Company for the replacement of the Big Sandy Unit 1 generation capacity as a coal fired generation resource include:

- BS1 Conversion: converting Big Sandy Unit 1 to a natural gas fired generation unit (BS1 Conversion). The projected cost to convert Big Sandy Unit 1 will be developed by American Electric Power Service Corporation's (AEPSC) Projects, Controls & Construction group. (AEPSC Projects Group).

- PJM Capacity Resource Request for Proposals (RFP): issue an RFP for 250 MW of PJM Generation Capacity Resources.

The Company will use the proposals (Proposals) received as a result of the 250 MW RFP along with the BS1 Conversion cost estimate to determine the least, reasonable cost solution to replacing the Big Sandy Unit 1 capacity as a coal fired generating unit.

The evaluation of the RFP and BS1 Conversion is not a commitment to convert (BS1 Conversion) or purchase (RFP) and shall not bind the Company or any affiliates of the Company in any manner. The Company in its sole discretion will determine which direction, if any, it wishes to take with respect to replacing the Big Sandy Unit 1 coal fired generation capacity, energy, and ancillary services.

The management and evaluation of this RFP will be directed by select AEPSC personnel that have been categorized into two groups – a Development Group and an Evaluation Group. The Development Group will be responsible for the design, development, and management of the overall RFP process, while the Evaluation Group will be responsible for evaluating the RFP Proposals and the BS1 Conversion cost as provided by the AEPSC Projects Group. Members of the Development and Evaluation Groups are separate groups from the AEPSC Projects Group or any Affiliate of the Company that may wish to participate in this RFP.

AEPSC and the Company will ensure that the bids received in response to this RFP along with the BS1 Conversion cost are evaluated in a consistent, transparent, and impartial manner.

1. Company Information

1.1. American Electric Power (AEP) is one of the largest electric utilities in the United States, delivering electricity to more than 5.3 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and Texas). AEP's headquarters are in Columbus, Ohio. More information about AEP can be accessed by visiting www.aep.com.

1.2. Kentucky Power Company provides service to approximately 173,000 customers in all or part of 20 eastern Kentucky counties and is headquartered in Frankfort, KY. The Company has approximately 1,233 miles of transmission lines and 11,242 miles of distribution lines. Its distribution operations are based in Ashland with service centers in Pikeville and Hazard. The Company also has area offices in Paintsville and Whitesburg. More information about the Company can be accessed by visiting www.kentuckypower.com.

2. Introduction

2.1. American Electric Power Service Corporation, a subsidiary of AEP is administering this Request for Proposals (RFP) on behalf of Kentucky Power Company (Company). AEPSC is requesting bids which will result in obtaining up to approximately 250 MW of PJM Generation Capacity Resources[1] (Resources).

2.2. Resources bid into this RFP must be capable of being on-line by June 1, 2015 and able to supply a "Bundled Product" that includes Capacity (MW), Energy (MWh), and Ancillary Services if available.

2.3. AEPSC is requesting Proposals from parties desiring to sell a Bundled Product through a Power Purchase Agreement (PPA), Tolling Agreement (TA), an Asset Purchase Agreement (APA), or Other Proposal (OTH) as further defined in this RFP.

In addition, AEPSC will be accepting Proposals from demand-side management (DSM) and cost-effective energy efficiency (EE) resources.

[1] PJM Generation Capacity Resource is a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of the PJM Reliability Assurance Agreement. A Generation Resource may be an existing Generation Resource or a Planned Generation Resource.

2.4. Energy scheduled as a result of any PPA, TA, or OTH agreement shall be scheduled via a unilateral schedule in the PJM InSchedule system with a Sink at the Big Sandy Unit 1 Pnode as further described in Section 4.4.2 *(Note: this scheduling requirement will enable the Company to utilize any proposed Resource in a manner similar to a Product produced from the Company's Big Sandy Unit 1resource. In addition, it will enable the Company to compare Proposals to the BS1 Conversion cost as referenced in the Background of this RFP).*

2.5. For each Proposal, a Seller shall offer only one Base Proposal. Sellers are encouraged to provide the Company with a Base Proposal that reflects what it believes is their best pricing Proposal. At no point in the evaluation process will a Seller have the opportunity to unilaterally change its Proposal.

2.6. For each Base Proposal, a Seller is allowed to submit up to three alternatives (each an "Alternative Proposal"). Alternative Proposals may be for different bid sizes, term of contract (15 years or greater), or alternate contract terms and conditions. Proposals based on a different site, technology, contract type, or fuel supply arrangement from the Base Proposal must be submitted as a separate Proposal.

2.7. The Company will allow affiliates (Affiliates) of the Company to participate in this RFP. Affiliates will be required to follow all of the requirements of this RFP including the process outlined in Section 3 regarding questions. If an Affiliate's Proposal is offered, its Proposal (i) shall be submitted in the same format and under the same rules and (ii) shall be evaluated in the same manner as other Proposals submitted into this RFP.

2.8. The Company has established a web page (www.kentuckypower.com/go/rfp) at its website for this RFP. AEPSC and Kentucky Power Company reserve the right to amend this RFP at any time and at its sole discretion. Any amendments to this RFP will be posted at the Company web page.

2.9. This RFP is not a commitment to purchase and shall not bind the Company or any affiliates of the Company in any manner. The Company in their sole discretion will determine which Seller(s), if any, it wishes to engage in negotiations that may lead to a binding contract.

3. RFP Questions

3.1. Throughout the RFP process, interested parties may submit questions regarding this RFP to AEPSC via:

- instructions located at the Company's website established for this RFP (www.kentuckypower.com/go/rfp) or
- by emailing 2013KentuckyPowerRFP@aep.com.

3.2. Questions submitted as outlined in Section 3.1 above will be reviewed by AEPSC. Those questions (and answers) which AEPSC views in its sole discretion to be of benefit to other potential RFP participants will be posted on the Q&A portion of the website. Posted questions and answers will not identify the originator of the question.

4. Scope

The following sub-sections describe the scope of this RFP. All questions regarding the scope of this RFP should be submitted through the Company's website or RFP email address as outlined in Section 3.

4.1. Product – the Company is seeking a low cost Bundled Product from PJM Generation Capacity Resources that includes the following.

- 4.1.1. Capacity (MW)
- 4.1.2. Energy (MWh)
- 4.1.3. Ancillary Services (if available)
- 4.1.4. Environmental Attributes[2] (if available)

4.2. Quantity – the Company is seeking Proposals for up to 250 MW, however, may procure more or less than 250 MW, and may aggregate Bundled Products from multiple Sellers to meet its needs, or select no offers at all.

- 4.2.1. Proposals shall have a minimum nameplate capacity size of 50 MW, with the exception of DSM / EE Proposals.
- 4.2.2. DSM and EE Proposals shall have a minimum size of 1 MW.

4.3. Delivery Period – The delivery of Capacity and Energy should begin no earlier than June 1, 2015.

- 4.3.1. Delivery period start dates later than June 1, 2015 will be accepted, however, Seller will be required to supply to the Company the PJM Capacity value for the period between June 1, 2015 and the actual delivery start period.
- 4.3.2. All Base Proposals, with the exception of DSM/EE Proposals, shall have a term of 15 years. Base Proposals with terms other than 15 years will be considered non-conforming and rejected from the RFP process. Sellers may provide terms of greater than 15 years within their Alternative Proposals.
- 4.3.3. DSM / EE Proposals shall have a minimum term of 5 years.

4.4. Energy Delivery (for PPA, TA, and OTH Proposals)

- 4.4.1. The Company and the Seller(s) will bilaterally establish and confirm a contract in PJM's InSchedule system (Contract) related to any agreement between the Company and the Seller.
- 4.4.2. The Contract will have the following key attributes:

---

[2] Environmental Attributes include, but are not limited to any associated renewable energy credits (RECs) and any other current or future environmental attributes, including any greenhouse gas emission reductions associated with the quantity contracted from a facility.

4.4.2.1. the "Schedule Confirmation Type" will be "Unilateral Buyer," such that the Company will have unilateral schedule confirmation rights for all schedules between the parties;

4.4.2.2. the "Sink" will be the Point of Delivery as defined in the table below;

Point of Delivery	
Pnode ID name	BIGSANDY
Pnode ID number	40243783
Location	Louisa, KY
County	Lawrence

4.4.2.3. the "Service Type" will be "Internal Bilateral Transaction".

4.5. Interconnection

4.5.1. The Point of Interconnection shall be the Facility's interconnection point with the PJM system.

4.5.2. All Proposals, at a minimum, must have completed the PJM Feasibility Study phase of the interconnection request process with PJM.

4.5.3. The Seller is responsible for all costs associated with transmission interconnections and system upgrades as required by PJM and the transmission operator.

4.5.4. The Seller is responsible for following the established PJM and transmission operator policies and procedures that are in effect regarding facility interconnection and operation associated with a utility's transmission system.

4.6. Proposal Types - the Company is interested in executing a contract ("Supply Agreement") from one or more of the following proposal types

4.6.1. Power Purchase Agreements ("PPA")

4.6.2. Tolling Agreements ("TA") – Seller pricing shall include the option of Seller providing the fuel, however, the Proposal shall also include an option where the Company will supply the fuel to the Resource.

4.6.3. Asset Purchase Agreements ("APA") – The Company will accept Proposals for assets that are currently in-service or will be in-service prior to June 1, 2015. The Company will not accept Proposals for partially built assets.

4.6.4. Other Proposals ("OTH") – Other Proposals are other power supplies or arrangements that do not fall into a PPA, TA, APA or DSM/EE category

4.6.5. Demand-side management ("DSM") or Cost-effective energy efficiency resources ("EE")

4.7. Pricing

4.7.1. Seller shall use Appendix A and any other attachments as needed to fully articulate the pricing of its Proposal.

4.7.2. Seller shall provide a summary of its essential terms and conditions associated with Seller's Proposal and pricing.

4.7.3. Prices must be firm, representing best and final data and quoted in U.S. dollars.

4.7.4. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

4.7.5. Pricing to include all Ancillary Service costs, taxes and other fees necessary for delivery of the Energy to the Point of Delivery as applicable.

4.7.6. All costs associated with interconnections and transmission, including any system upgrades, as required by PJM up to the Point of Delivery shall be included in the Seller's pricing where appropriate under current FERC orders and rulings.

4.7.7. DSM / EE Proposals: Seller shall fully describe in Appendix D or other attachment the pricing associated with its Proposal.

4.8. Ancillary Services

4.8.1. Under a Supply Agreement, the Company prefers to have the unrestricted right to utilize all Ancillary Services associated with generation being offered by the Seller. In addition, the Company desires to have the unrestricted rights to any future Ancillary Services defined by the industry and capable of being provided by the generation capacity being offered.

4.8.2. The Seller shall describe the Ancillary Service capability of the Facility (Regulation, Synchronized Reserve, Black Start Service, DA Scheduling Reserve, etc.)

4.8.3. All Ancillary Services must be provided in accordance with the requirements of PJM and the transmission operator.

4.8.4. The Ancillary Services that would be available to the Company should not be limited to those defined in this section.

4.8.5. In the case where the Company purchases only part of the generation capacity from a unit, system or facility, then the Company desires to have unrestricted rights to Ancillary Services on a prorated basis.

4.9. DSM / EE Proposals must be from resources located within the Company's service area.

5. RFP Schedule

5.1. The following schedule and deadlines apply to this RFP. AEPSC and the Company reserve the right to revise this schedule at any time and at its sole discretion. Any revisions to the schedule will be posted to the RFP website.

5.2. All Proposals must be complete in all material respects and be received no later than 4 p.m. EST on Tuesday, June 11th at the AEPSC Columbus, OH location as defined in Section 6 of this RFP.

RFP Issued	Thursday, March 28, 2013
Confidentiality Agreements	Friday, May 24, 2013
Proposals Due Date	Tuesday, June 11, 2013
RFP Short-List Identified	Friday, July 12, 2013
Final Decision (Recommended)	tbd

6. Proposal Submittal

One hard copy and one electronic copy on CD of the Proposal(s) shall be submitted by the Proposal Due Date as outlined in Section 5 of this RFP to:

American Electric Power Service Corporation
Kentucky Power Company RFP Administrator
155 W. Nationwide Blvd
Columbus, OH 43215

7. Key Terms and Conditions

For a Supply Agreement, the Seller's Proposal should include, where applicable to the Seller's Proposal, the following terms and conditions, among other things:

7.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, operations and maintenance costs, as applicable.

7.2. Pricing shall include all pricing and terms for Capacity, associated Energy, and Ancillary Services.

7.3. Seller will guarantee the annual and seasonal availability.

7.4. Seller will be responsible for any and all compliance related costs and fines (environmental, NERC, FERC, PJM, etc) incurred due to the non-compliance of the asset(s) designated to supply Capacity, Energy, and Ancillary Services to the Company.

7.5. Seller shall be responsible for ALL reporting requirements under NERC, PJM, etc.

7.6. Seller shall be responsible for offering Company's Capacity, Energy and Ancillary Services into the PJM market.

7.7. For the sale of generation capacity and energy to the Company under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold.

7.8. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller.

7.9. Financial Capability

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

7.9.2. Upon execution of a Supply Agreement, Seller will be required to provide Security in the form of an irrevocable standby letter of credit (LOC), cash, or a corporate guaranty from a credit worthy entity, to protect the Company's customers in the event of default by the Seller. The amount and terms of the Security will be subject to approval by the Company based upon the Company's standards.

8. Proposal Content

8.1. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. Seller shall use Appendix C as a reference of the material required to be submitted with Seller's Proposal.

8.2. The Company reserves the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Company's internal evaluation of cost, risk, and value.

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

9. Treatment of Proposals

9.1. The Company reserves the right, without qualification, to select or reject any or all Proposals and to waive any formality, technicality, requirement, or irregularity in the Proposals received.

9.2. The completed Appendices and any supplement information submitted by the Seller may be utilized in any filings with regulatory agencies related to this RFP.

9.3. The Company reserves the right to solicit additional Proposals, to modify the RFP or request additional information, as necessary, to complete its evaluation of the Proposals received.

9.4. Sellers who submit Proposals do so without recourse against the Company for either rejection by the Company or failure to execute an agreement for purchase of Capacity and/or energy for any reason.

10. RFP Proposal Evaluation

10.1. Initial Review

Proposals will be thoroughly reviewed and assessed to ensure that each meets ALL applicable content requirements as described in Section 8 – Proposal Content. Proposals that meet all the requirements (as applicable) of the RFP shall be considered conforming. Proposals will be deemed non-conforming if they do not meet all the requirements specified in the RFP and will be rejected. During the initial screening process, the Company reserves the right, but is not obligated, to contact Seller(s) to clarify Proposal terms or to request additional information.

10.2. Evaluation

The Company will use a multi-stage evaluation process to review Proposals. The evaluation process followed will depend on the number and nature of the Proposals received. The evaluation process will consider all applicable factors including, but not limited to, the following to determine the reasonableness of the Proposal and the projected least, reasonable cost:

- Terms of the proposal
- Exceptions to the terms and conditions as outlined in this RFP
- Proposal Pricing
- Impact of Proposal to Company's balance sheet and credit rating
- Seller's creditworthiness and experience
- Proposed date of commercial operation (on-line)
- Status of interconnection process with PJM
- Project capacity
- Regulatory considerations
- Development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission;

At the conclusion of the evaluation process, a Short-list of Proposals will be identified for further evaluation and comparison to the BS1 Conversion cost as referenced in the Background section (page 3) of this RFP. If the Company determines that a Proposal(s) is in the best interest of the Company and its customers, the Company will enter into negotiations which may lead to the execution of a definitive agreement(s). Sellers of Proposals that are not selected to the Short-list will be notified that their Proposals were not selected to the Short-list.

10.3. Seller agrees to cooperate, to the fullest extent necessary, to obtain any and all State, Federal, or other regulatory approvals required for the effectiveness of a transaction.

10.4. Execution of any agreement shall also be dependent upon AEPSC and Kentucky Power Company obtaining sufficient assurance that the product purchased pursuant to the any agreement will be recognized for full recovery in the rates charged to its jurisdictional customers. The determination of what constitutes "sufficient assurance" shall be at the sole discretion and judgment of AEPSC and Kentucky Power Company.

11. Confidentiality

11.1. Attached as Appendix F is the Company's Form Confidentiality Agreement (CA). If Seller elects, they may complete the CA and forward electronically to 2013KentuckyPowerRFP@aep.com for execution by the Company.

11.2. AEPSC will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all bids submitted. Sellers should clearly identify each page of information considered to be confidential or proprietary. AEPSC reserves the right to release any Proposals to agents or consultants for purposes of Proposal evaluation. AEPSC's disclosure policies and standards will automatically bind such agents or consultants. Regardless of the confidentiality, all such information may be subject to review by the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. Under such circumstances, AEPSC will make all reasonable efforts to protect Seller's confidential information.

12. Seller's Responsibilities

12.1. Proposals and bid pricing must be valid for at least 120 days after the Proposal Due Date, upon which time Proposals shall expire unless the Seller has been notified and selected as a Short-listed Seller or as a final award recipient.

12.2. It is the Seller's responsibility to submit all requested material by the deadlines specified in this RFP. The Seller should make its Proposal as comprehensive as possible so that the Company may make a definitive and final evaluation of the Proposal's benefits to its customers without further contact with the Seller.

12.3. Sellers are responsible for the timely completion of the project and are required to submit proof of their financial and technical wherewithal to ensure the successful completion of the project.

12.4. The Company shall not be liable for any expenses Sellers incur in connection with the preparation and submission of a Proposal and/or any subsequent negotiations. The Company will not reimburse Sellers for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Company at its sole discretions.

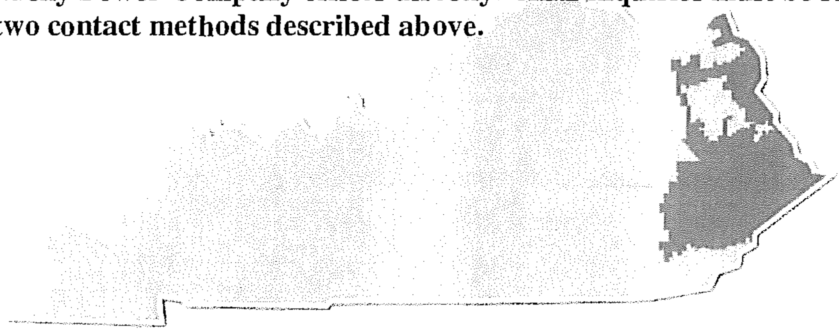
13. Contacts

All correspondences and questions regarding this RFP must be:

1. directed to the "Questions" section of the website established for this RFP (www.kentuckypower.com/go/rfp) or

2. by emailing 2013KentuckyPowerRFP@aep.com.

NOTE: Sellers or parties interested in participating in this RFP shall not contact the Kentucky Power Company offices directly. ALL inquiries must be submitted via the two contact methods described above.



2013 Kentucky Power Company 250 MW RFP

Appendix A

Company Information

Seller (Company):
Contact Name:
Contact Title:
Address:
City: State: Zip Code:
Work Phone: Cell Phone:
Email Address:

General Project Information

Project Name / Description:				
Resource Type : *(e.g. NG Simple Cycle, Combined Cycle, Pulverized Coal, CFB, Wind, Hydro, DSM, EE, etc.):*				
Fuel Type (Primary / Secondary) :				
Project Location:				
Estimated On-line Date:		Expected Annual Production (MWh):		

Project Capacity Values, MW	Nameplate Rating	Winter Rating	Summer Rating	PJM Capacity Value

Is proposed MW the entire facility capacity (Y / N);

If no, then how large is the entire facility (MW)?

PJM Interconnection Summary

Feasibility Study Complete (Y/N):	PJM Queue #:
Interconnecting Utility / Location:	

2013 Kentucky Power Company 250 MW RFP

Substation:	Interconnection Voltage:
PJM Interconnection Status (describe):	

Proposal Type (check one)				
PPA	TA	OTH	DSM	EE

Pricing

Sellers shall provide a detailed written description of all pricing formulas including a detailed description of all sub-components. As noted in the RFP, the Company requires a Base Proposal, however the Company will allow Sellers to include up to three other Alternatives in their Proposal. If Seller elects to offer Alternatives, then Seller shall submit separate Proposal Pricing Sheets for each Alternative.

The following requirements for each of the Proposal Types shall be used as a guide. It is the Sellers responsibility to clearly articulate in this Appendix and any associated attachments the pricing component to the Seller's proposal.

PPA Proposals

Project Name: ______________________________

Term: [________] to [________]

Contract Quantity: [__________] MW of Capacity and Energy

Capacity Charge: [_________] $ / kw-month, define any annual price escalation

Heat Rate: [_________] Btu / kWh, provide heat rates at all dispatch points

Variable O&M: [_________] $ / MWh, define any annual price escalation

Fuel Cost: (Fuel Cost Index Name) or [ ] $ / MMBtu, provide a fuel price index and any adders, escalation or adjustments to the index to be used to price fuel delivered to the Facility, or provide the actual cost of fuel delivered to the facility.

Energy Payment: [_________] $ / MWh, define any annual price escalation

Start-up Payment: [_________]: $ / start

Other Operating Related Charges: [Define cost and parameters for charges]

TA Proposals

Project Name: ___________________________________

Term: [_________] to [_________]

Contract Quantity: [________] MW of Capacity and Energy

Capacity Charge: [_________] $ / kw-month, define any annual price escalation

Heat Rate: [_________] Btu / kWh, provide heat rates at all dispatch points

Variable O&M: [_________] $ / MWh, define any annual price escalation

Fuel Cost: (Fuel Index Name) or [ ] $ / MMBtu, provide a fuel price index and any adders, escalation or adjustments to the index to be used to price fuel delivered to the Facility, or provide the actual cost of fuel delivered to the Facility. For Tolling Agreements, Kentucky Power Company reserves the right to purchase and supply the fuel to the Facility itself.

Start-up Payment: [_________]: $ / start

Other Operating Related Charges: [Define cost and parameters for charges]

Asset Purchase Agreements

Project Name:

Nameplate Capacity:

Sale Price, $M: [ ]

Proposed Asset Transfer Date: [ ]

Other Proposals

For "Pricing Terms" for all non-PPA proposals, Bidder shall provide these terms on a separate sheet providing a complete detail of such terms.

Appendix B

Operating Characteristics

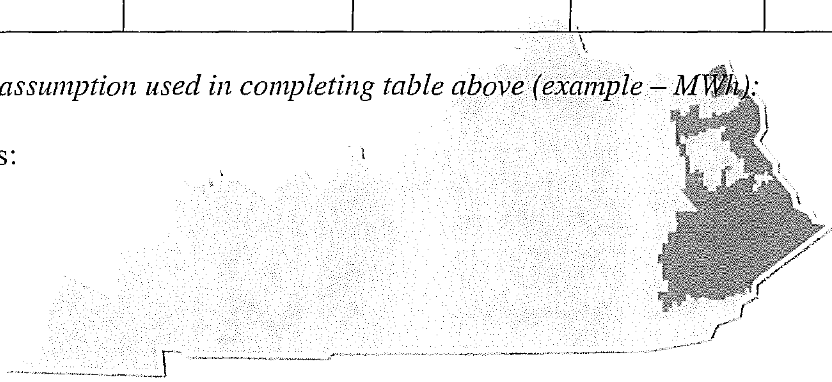
Heat Rate – Summer (Btu /kwh at all loading points allowed by the Proposal)	
Heat Rate – Winter (Btu /kwh at all loading points allowed by the Proposal)	
Summer Capacity – Max (MW)	
Summer Capacity – Min (MW) or at all loading points allowed by the Proposal	
Winter Capacity – Max (MW)	
Winter Capacity – Min (MW) or at all load points allowed by the Proposal	
Output (MW) in 10 minutes from Start	
Ramp Rate (MW / min) – Normal	
Ramp Rate (MW / min) – Maximum	
Start-up time (hot) to minimum capability	
Start-up time (hot) to maximum capability	
Start-up time (warm) to minimum capability	
Start-up time (warm) to maximum capability	
Start-up time (cold) to minimum capability	
Start-up time (cold) to maximum capability	
Auxiliary Load (at all loading points allowed by the Proposal)	
Minimum run time	
Minimum down-time	
Forced Outage Rate	
Scheduled Outage Rate	
Annual Availability (%)	
Production Constraints:	
Ancillary Services (describe):	

Air Emissions

Emissions	Primary Fuel		Secondary Fuel	
	Lb / MWh	Tons / Year	Lb / MWh	Tons / Year
Sulfur Dioxide				
Nitrogen Oxide				
Carbon Monoxide				
Carbon Dioxide				
Mercury				
Particulates (PM / PM 10)				
Volatile Organic Compounds				

Please note assumption used in completing table above (example – MWh):

Assumptions:



Appendix C

Proposal Requirements

1. An executive summary of the bid's characteristics and timeline, including any unique aspects and benefits.
2. Seller shall complete Appendix A as applicable.
3. Seller shall complete Appendix B as applicable.
4. Sellers with DSM/EE Proposals shall complete Appendix D. DSM/EE Proposal documents shall be limited to 30 pages. Additional information may be submitted electronically (eg. CD, memory stick).
5. Seller shall fully describe any exceptions it takes towards any terms and conditions as described in Section 7 or other parts of this RFP.
6. Experience and References
    a. Provide a general description of the Seller's background and experience in utility scale power projects similar to its proposal, including any affiliated companies, holding companies, subsidiaries or predecessor companies presently or in the past engaged in developing energy power supply projects.
    b. Provide three (3) or more references from projects where the bidder, or any of its affiliates, has completed the development and construction of a power project similar to the one proposed to the Companies. If the bidder has fewer than three projects, it shall provide as many references as possible.
7. Seller shall provide a comprehensive narrative of the development status of any new generation project intended to be used to meet Seller's obligations to the Company. Seller's narrative shall include the following.
    a. Key project participants including owners, operators, engineer / contractors, fuel suppliers.
    b. Status of engineering and design work.
    c. A comprehensive development and construction schedule.
    d. A listing of all required permits and governmental approvals and their status.
    e. A listing of all required electric interconnection and or transmission agreements and their status.
    f. A financing plan.
    g. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.
8. Seller shall provide copies of all PJM Interconnection studies. In addition, Seller shall provide the following:

a. Impedance of the generator step-up transformer.

b. Transient and sub-transient characteristics of the generator.

9. Project Site

a. Seller shall provide proof or status of ownership or control of site.

b. Seller shall provide a summary describing whether the site has been assessed for environmental contamination, has any known environmental issues, and if a Phase 1 environmental assessment has been completed.

c. Has the site been assessed for environmental contamination? Describe any known environmental issues?

d. Describe status of all required permits.

e. If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.

10. Legal Proceedings

a. List all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been or are engaged that could affect bidder's performance of its bid.

b. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.

11. Technology / Equipment

a. Technology employed (combined cycle, pulverized coal, CFB, etc.)

b. Provide details regarding the technology selected, major equipment manufacturer identified, status of equipment purchases.

12. Existing Facilities (including **Asset Purchase Agreements**) - For existing facilities, at a minimum, provide the following information for each of the last 5 years of operating history;

a. Energy generated

b. Capacity factor

c. Number of start-ups

d. Average heat rate

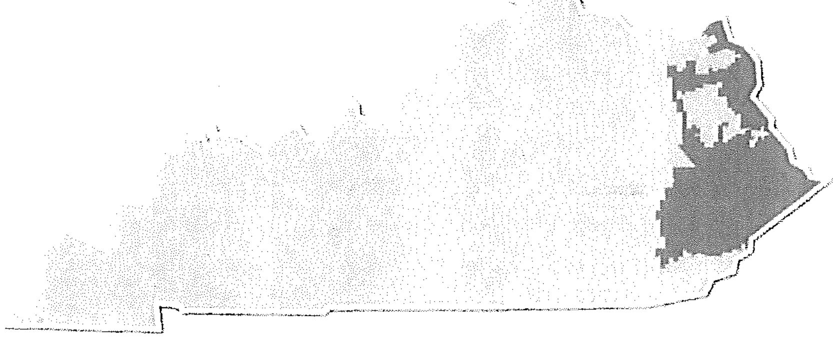
e. On-Peak availability

f. Fixed O&M Costs

g. Variable O&M Costs

h. Capital expenditures

13. Sellers of assets (Asset Purchase Agreements) shall provide a description of the facility's major equipment
14. Seller shall provide a copy of air permit or permit application(s) if available.
15. Seller shall provide a summary of the timing and status of all permit applications including water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.
16. Seller shall provide its operations plan – describe the entity who will be performing operations and maintenance of the facility
17. Seller shall provide its fuel supply plan.
18. Subsidies – Bidders must indicate if their proposal is dependent upon any existing state or federal tax credit or grant program and expiration of said program.
19. Maintenance Outages
    a. Seller shall describe the required annual (routine) maintenance outage schedule and associated tasks.
    b. Seller shall describe major outages schedules, general scope and frequency



Appendix D

DSM / EE - Proposal Requirements

Company Information

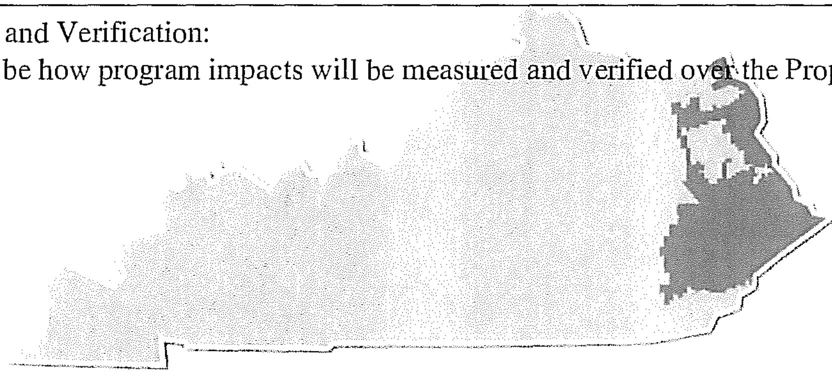
Seller (Company):		
Contact Name:		
Contact Title:		
Address:		
City:	State:	Zip Code:
Work Phone:	Cell Phone:	
Email Address:		

Seller's with DSM and EE Proposals shall fully describe below or on a separate attachment the resource being offered, size/quantity, term, pricing, and essential terms and conditions associated with their offering. DSM/EE Proposal documents shall be limited to 30 pages. Additional information may be submitted electronically (eg. CD, memory stick).

General Project Information

Project Name / Description:

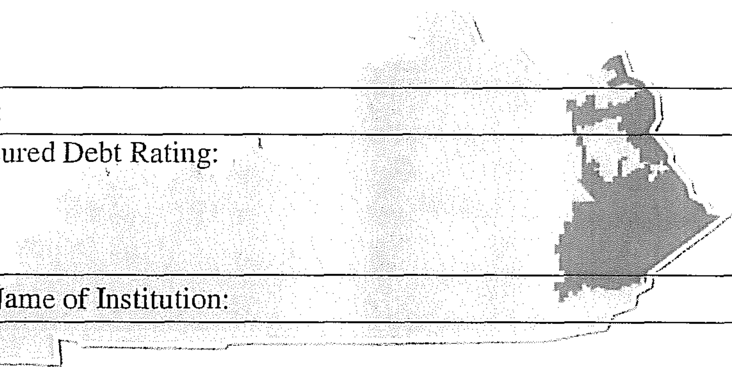
Describe End-uses Impacts: • Provide monthly projected peak and energy impacts over the Proposal Term • Provide hourly reduction load shapes over the Proposal Term by end-use and aggregated for the Proposal • Provide measure life and any degradation in peak and energy impacts over the Proposal Term
Measurement and Verification: • Describe how program impacts will be measured and verified over the Proposal Term



Appendix E

Bidder's Credit-Related Information

Full Legal Name of the Bidder:
Type of Organization (Corporation, Partnership, etc.):
Bidder's % Ownership in Proposed Project:
Full Legal Name(s) of Parent Corporation: 1. 2. 3.
Entity Providing Credit Support on Behalf of Bidder (if applicable): Name: Address: City: Zip Code:
Type of Relationship:
Current Senior Unsecured Debt Rating: 1. S&P: 2. Moodys:
Bank References & Name of Institution:
Bank Contact: Name: Title: Address: City: Zip Code: Phone Number:
Legal Proceedings: As a separate attachment, please list all lawsuits, regulatory proceedings, or arbitration in which the Bidder or its affiliates or predecessors have been or are engaged that could affect the Bidder's performance of its bid. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.
Financial Statements: Please provide copies of the Annual Reports for the three most recent fiscal years and quarterly reports for the most recent quarter ended, if available. If available electronically, please provide link:



Appendix F

Mutual Confidentiality Agreement

Email to: 2013KentuckyPowerRFP@aep.com
American Electric Power Service Corporation
155 West Nationwide Boulevard
Suite 500
Columbus, OH 43215
Fax: (614) 583-1611

Due: Friday, May 24, 2013

This Mutual Confidentiality Agreement ("Agreement") dated as of ___________, 2013 ("Effective Date") is made and entered into by and between American Electric Power Service Corporation ("AEPSC"), as agent for Kentucky Power Company, and *insert full legal name*, a(n) *insert state of formation insert type of company* ("Bidder").

Recitals:

I. Bidder is or is considering submitting a proposal (the "Proposal") in response to a Request for Proposals (the "RFP") issued by AEPSC for energy, capacity, and ancillary services as described in the RFP. If submitted, the Proposal will become the property of AEPSC and shall be held confidential under terms of the RFP.

II. It may become desirable that AEPSC and Bidder exchange other confidential information pursuant to questions, responses or other communications that are not contained in the Proposal and which the parties desire to protect as confidential.

III. In addition, if the Proposal, if submitted, is selected by AEPSC, then Bidder and AEPSC will negotiate about a proposed agreement between AEPSC and Bidder to implement the Proposal (the "Proposed Agreement"). Bidder and AEPSC want to keep all negotiations concerning the Proposed Agreement, including the Proposed Agreement itself and all drafts of the Proposed Agreement, confidential.

IV. The parties are willing to exchange such confidential information pursuant to the terms of this Agreement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the parties agree as follows:

Section 1. Definitions.

1.1. (a) "Confidential Information" means any information that is disclosed by the Disclosing Party to the Receiving Party or its Representatives in connection with the RFP or any Proposed Agreement (collectively, the "Transaction"), whether before or after the date hereof and irrespective of the format in which the information is provided. For avoidance of doubt, "Confidential Information" includes:

(i) Written information or machine-readable data, including questions, responses or communications in connection with AEPSC's RFP or any Proposed Agreement, notes, reports, assessments, specifications, drawings, financial statements and projections, software and databases, customer information, sales and marketing strategies, and any other written information or machine-readable data;
(ii) Orally conveyed information, including but not limited to demonstrations that are directly related to written or other tangible Confidential Information;
(iii) Any hardware, including but not limited to samples, devices and any other physical embodiments delivered to the Receiving Party;
(iv) Any Evaluation Material; or
(v) The existence of this Agreement, the terms of this Agreement and any Proposed Agreement, including all drafts of the Proposed Agreement and all negotiations concerning the Proposed Agreement, that may arise stemming from the Bidder's Proposal.

(b) "Confidential Information" does not include information which:

(i) is, or subsequent to disclosure becomes, part of the public domain through no fault of the Receiving Party;
(ii) is lawfully disclosed to the Receiving Party by a third party which, to the knowledge of the Receiving Party, does not have a confidentiality obligation to the Disclosing Party;
(iii) was lawfully in the possession of the Receiving Party prior to disclosure by the Disclosing Party; or
(iv) is lawfully and independently developed by the Receiving Party without use of the Confidential Information disclosed by the Disclosing Party.

1.2. "Disclosing Party" means the party disclosing Confidential Information.

1.3. "Evaluation Material" means notes, reports or other documents which reflect, interpret, evaluate, include or are derived from the Confidential Information.

1.4. "Receiving Party" means the party receiving Confidential Information.

1.5. "Representatives" means a party's employees, officers, directors, attorneys, accountants, consultants, advisors and agents (including potential lenders, equity partners, underwriters, or other parties involved in the Transaction for the party), and the party's affiliates and the employees, officers, directors, attorneys, accountants, consultants, advisors and agents thereof.

Section 2. Confidentiality. Except as provided in Section 5, the parties hereby agree that the Confidential Information will be kept confidential during the term of this Agreement. The parties also agree that without the prior written consent of the Disclosing Party, the Confidential Information will not be disclosed by the Receiving Party, in whole or in part, to any other person except as provided herein. Each party shall use the same care in protecting the other's Confidential Information as it uses to protect its own confidential information, provided that neither party shall use less than reasonable efforts to protect the other's Confidential Information. Notwithstanding the foregoing, the Receiving Party may (a) disclose Confidential Information to its Representatives whose access is necessary to conduct the evaluations and negotiations in connection with the Transaction, or for supervisory, regulatory or similar purposes, and who have been informed of and have agreed to abide by the confidentiality restrictions contained in this Agreement and (b) make a limited number of copies of the Confidential Information in order for the Receiving Party to adequately use the Confidential Information subject to the terms and conditions of this Agreement. Each party agrees to be responsible for the actions, uses and disclosures of any of its Representatives in accordance with the terms and restrictions of this Agreement.

Section 3. Ownership and Use of Confidential Information. All Confidential Information (except Evaluation Material) shall remain the property of the Disclosing Party. No license or other rights under any patents, trademarks, copyrights or other proprietary rights is granted or implied by the disclosure of the Confidential Information. Neither party shall use the Confidential Information for any purpose other than for evaluation of and negotiations relating to the Transaction.

Section 4. Disposition of Confidential Information. The Receiving Party, upon written request from the Disclosing Party, shall promptly return or destroy all Confidential Information in its possession; provided, however, with respect to Evaluation Materials, the Receiving Party may at its discretion destroy such Evaluation Material. If requested by the Disclosing Party, the Receiving Party shall provide the Disclosing Party with a certification that all Confidential Information and Evaluation Material has either been returned or destroyed, as appropriate. Notwithstanding the foregoing, the Receiving Party may retain one copy of the Confidential Information solely for archival purposes and for the purpose of demonstrating compliance with this Agreement. The return or destruction of the

Confidential Information shall not extinguish any rights or obligations under this Agreement with respect to the Confidential Information.

Section 5. Legally Required Disclosures. If the Receiving Party or its Representatives become subject to a bona fide requirement or request by any regulatory, governmental, judicial or supervisory authority (by subpoena, oral deposition, interrogatories, request for production of documents, civil investigative demand, administrative order or otherwise), to disclose any of the Confidential Information, or if such disclosure is necessary in order to obtain or maintain regulatory or governmental approvals, applications or exemptions, the Receiving Party will provide the Disclosing Party with as much advance notice as and to the extent as permitted and practicable to afford the opportunity to seek an appropriate protective order or other appropriate remedy to prevent the disclosure. The Receiving Party or any of its Representatives being compelled to disclose such Confidential Information will reasonably cooperate with the Disclosing Party, at its expense, to enable the Disclosing Party to obtain a protective order or other reliable assurance that confidential treatment will be accorded the same (e.g. confidentiality agreement). If such protective order or other appropriate remedy (e.g. confidentiality agreement) is not obtained, the Receiving Party or any of its Representatives being compelled to disclose such Confidential Information may disclose the information without liability hereunder provided that the party may only furnish that portion of the Confidential Information which is legally required or necessary.

Section 6. Term. If the Bidder's Proposal and/or related negotiations do not result in a final agreement, then this Agreement is effective for two (2) years from the Effective Date stated above. If the negotiations result in a final agreement, then this Agreement is effective until two (2) years after the termination of the final agreement.

Section 7. No Warranties. The Disclosing Party makes no representations or warranties as to the reliability, accuracy or completeness of the Confidential Information. The Disclosing Party shall not be subject to any liability to the Receiving Party based on the Receiving Party's use of the Confidential Information.

Section 8. Remedies. The parties acknowledge that improper or unauthorized use or disclosure of Confidential Information could cause irreparable harm to the Disclosing Party and that monetary damages would not be an adequate remedy for a breach of this Agreement. In the event of any breach or threatened breach of this Agreement, the non-breaching party shall be entitled to pursue injunctive and other equitable relief, and the breaching party agrees to waive any requirement for the posting of a bond in connection with such remedy. Such injunctive and equitable relief shall not be deemed to be the exclusive remedy for a breach of this Agreement, but shall be in addition to all other available remedies. In no event shall either party be liable to the other for any incidental, indirect, special, punitive or consequential damages (including without limitation damages for lost profits).

Section 9. Relationship of Parties. Neither party shall have any obligation to commence or continue discussions or negotiations, to exchange any Confidential Information, to reach or execute any agreement with the other party, to refrain from engaging at any time in any business whatsoever, or to refrain from entering into or continuing any discussions, negotiations or agreements at any time with any third party, until each party executes a definitive agreement. Until such definitive agreement is executed, neither party shall have any liability to the other party with respect to the Transaction except as set forth in this Agreement. Neither party shall have any liability to the other party in the event that, for any reason whatsoever, no such definitive agreement is executed.

Section 10. General.

10.1 Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Kentucky.

10.2 Entire Agreement. This Agreement constitutes the entire Agreement between the parties, supersedes any prior understandings or representations relating to the confidential treatment of the Confidential Information, and shall not be modified except by a written agreement signed by both parties.

10.3 Assignability. This Agreement may not be assigned by either party without the prior written consent of the other party; provided, however, that AEPSC may assign this Agreement to one or more of its affiliated companies.

10.4 Severability. All provisions of this Agreement are severable, and the unenforceability of any of the provisions of this Agreement shall not affect the validity or enforceability of the remaining provisions of this Agreement.

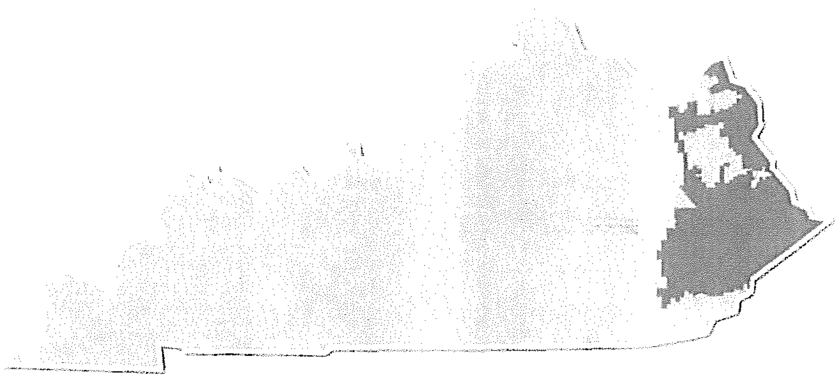
10.5 No Waiver. Failure of either party to insist upon strict performance of any of the terms and conditions shall not be deemed to be a waiver of those terms and conditions.

10.6 Counterparts and Faxed Signatures. This Agreement may be executed in counterparts, and in the absence of an original signature, faxed signatures will be considered the equivalent of an original signature.

10.7 Notices. Notices shall be in writing and shall be sent to the addresses listed below, either by personal delivery, by the U.S. Mail, overnight mail, fax or other similar means. All notices shall be effective upon receipt.

The parties have signed this Agreement effective as of the later signature date set forth below.

SIGNATURES ON FOLLOWING PAGE



2013 Kentucky Power Company 250 MW RFP

The parties have signed this Agreement effective as of the later signature date set forth below.

American Electric Power Service Corporation, as agent for Kentucky Power Company

By:____________________________

Print Name:_____________________

Title: __________________________

Date:__________________________

[BIDDER: insert full legal name]

By:__________________________________

Print Name:___________________________

Title:________________________________

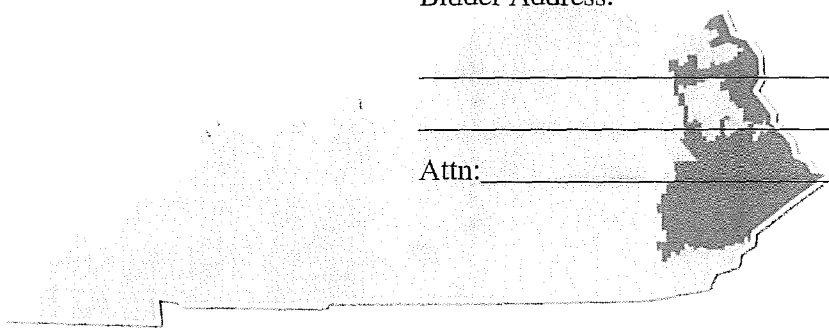
Date:________________________________

Bidder Address:

____

____

Attn:_________________________________



December 4, 2013

Disclaimer: This drawing is not an actual survey, and is for general information purposes only.

Cartography: AEP Real Estate Asset Management Dept.
Shaen Somerlot

Exhibit 3, Page 2 of 3

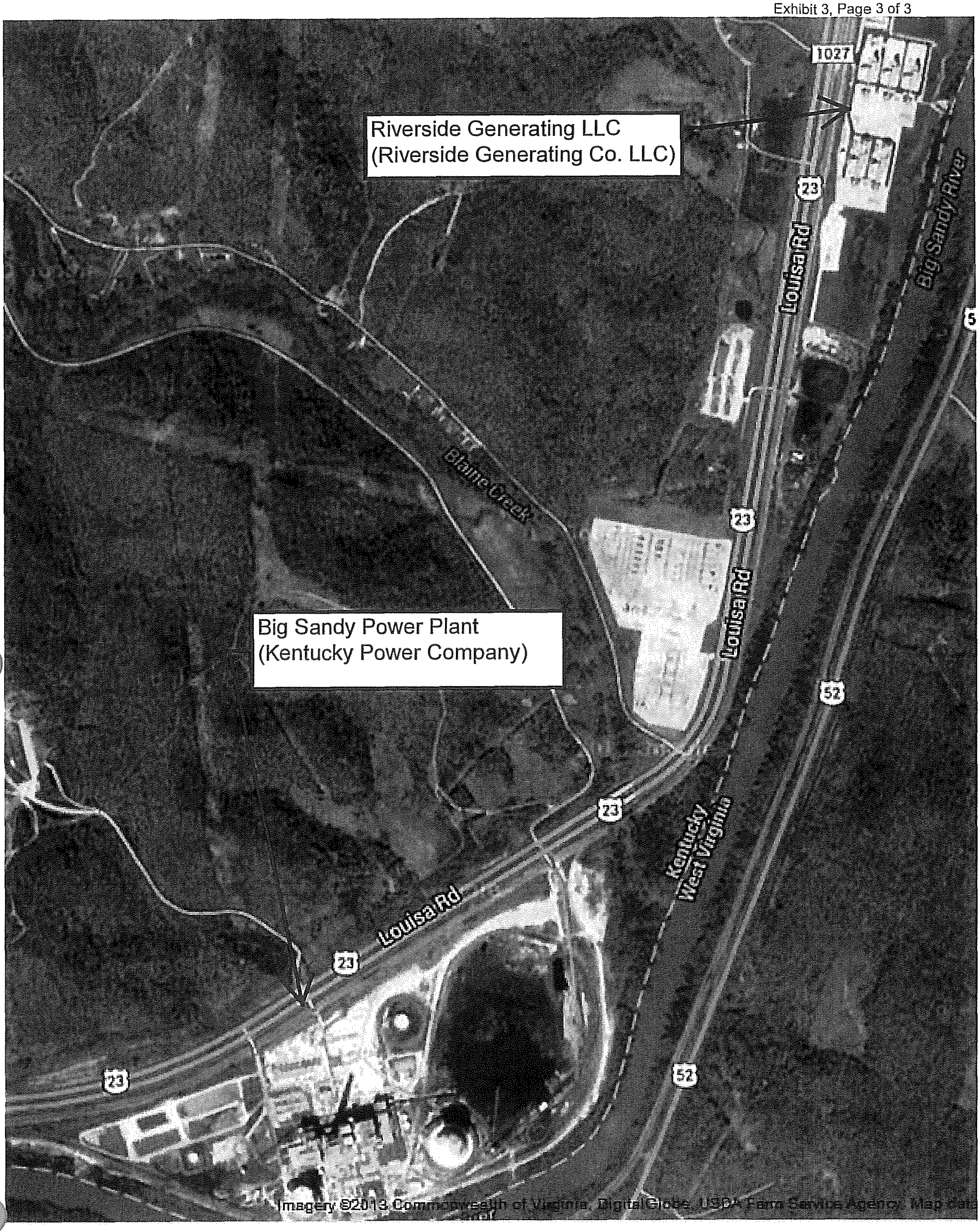


Image taken from Goole Maps, December 2013

EXHIBIT 4, Page 1 of 3

CONFIDENTIAL - CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII)

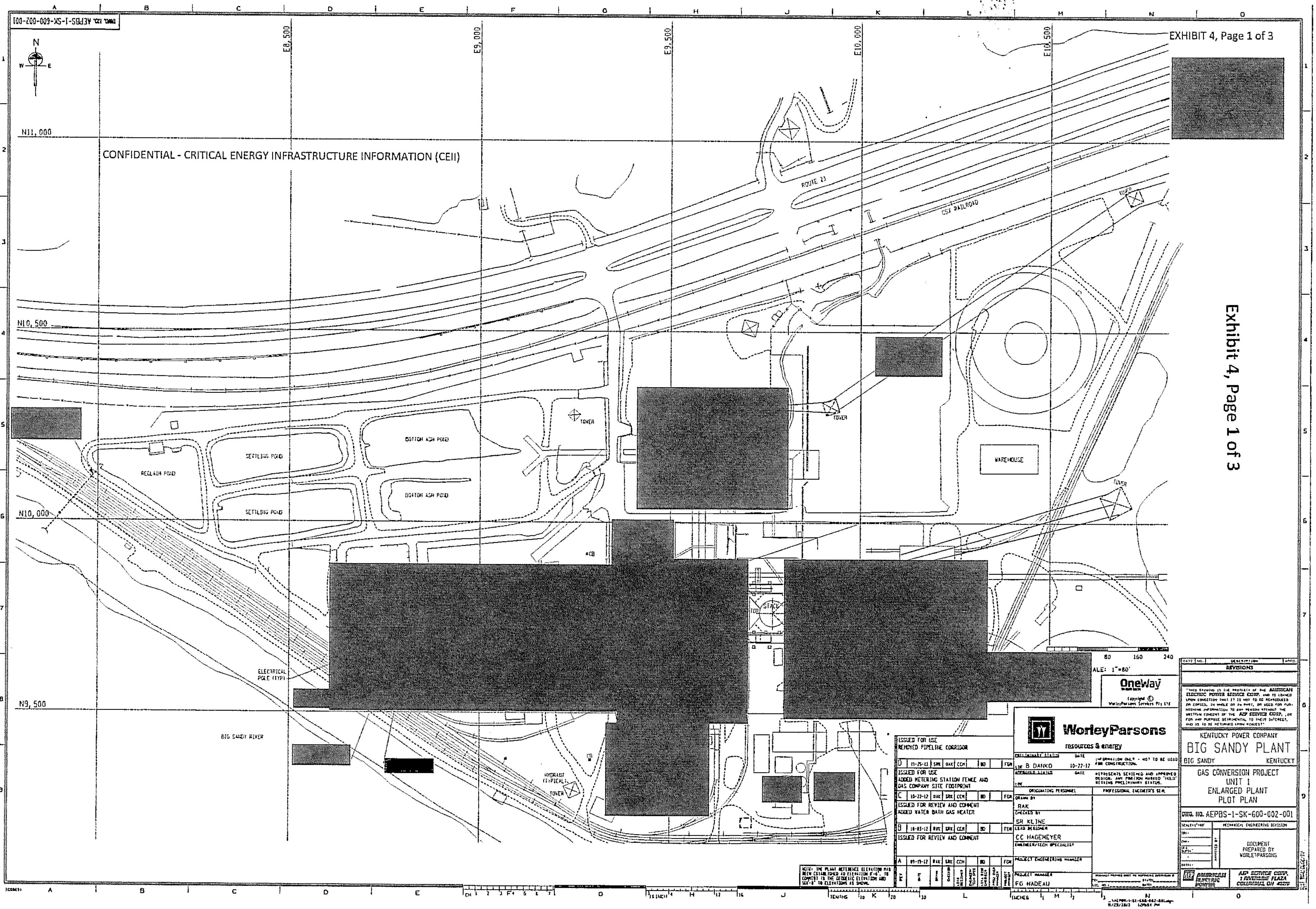
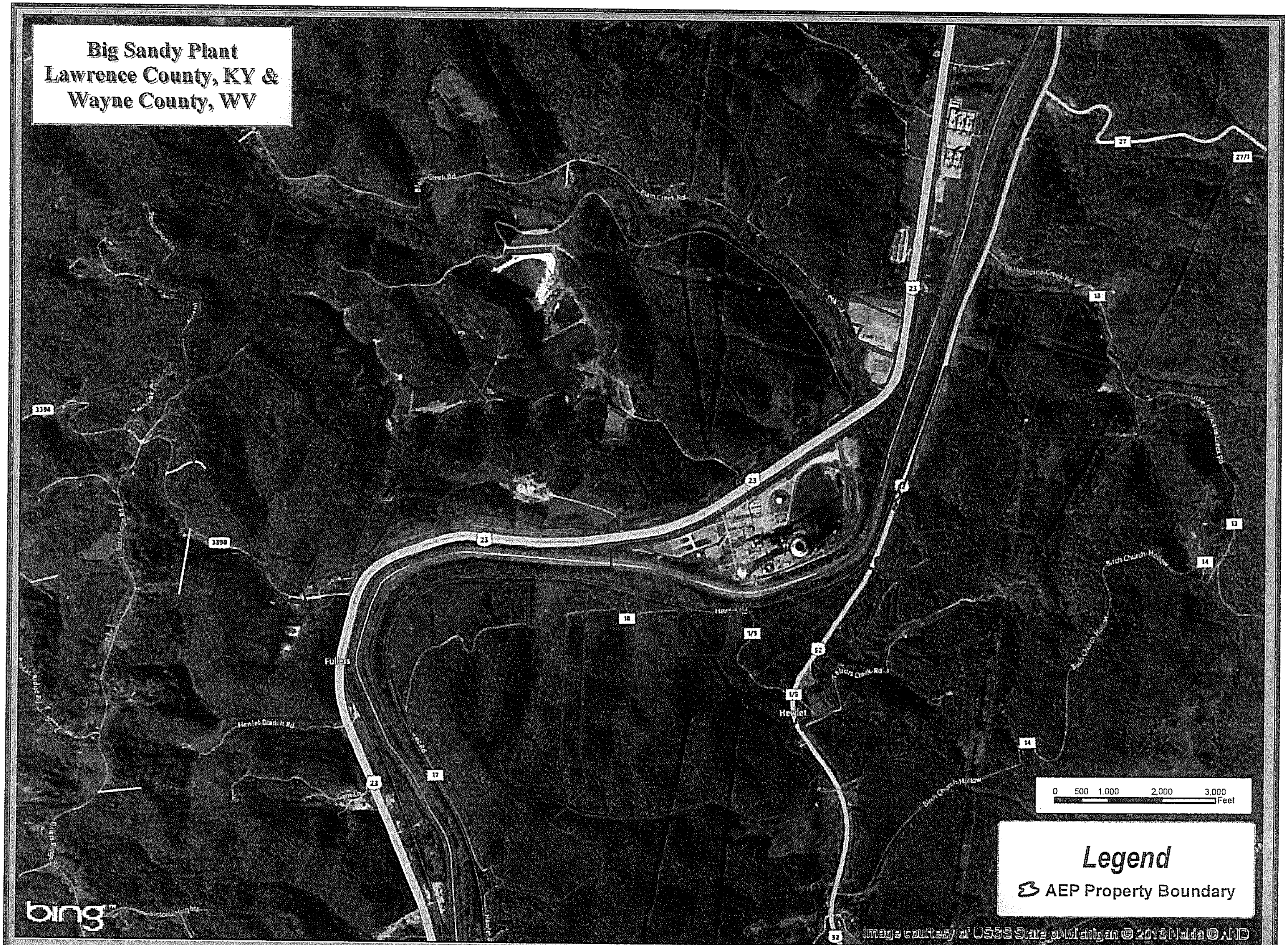


Exhibit 4, Page 1 of 3



December 4, 2013

Disclaimer: This drawing is not an actual survey, and is for general information purposes only.

Cartography: AEP Real Estate Asset Management Dept.
Shaen Somerlot

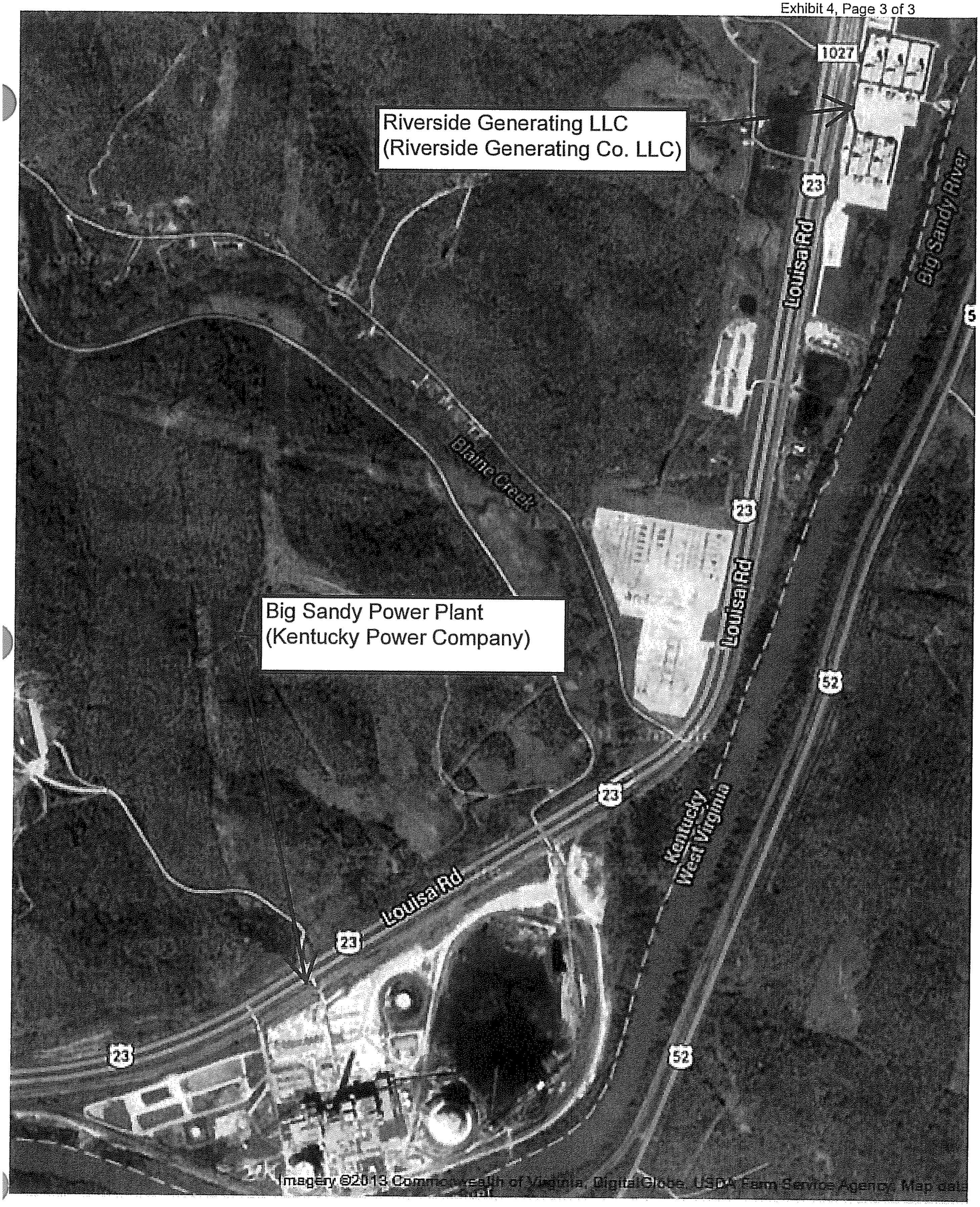


Image taken from Goole Maps, December 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

The Application Of Kentucky Power Company For (1) A		
Certificate Of Public Convenience And Necessity	)	
Authorizing Kentucky Power To Convert The Existing	)	
Big Sandy Unit 1 To Be Exclusively Fueled By Natural Gas	)	Case No. 2013-
(2) For Declaratory Rulings; And (3) For All Other		
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

JOSEPH A. KARRASCH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Joseph A. Karrasch, being duly sworn, deposes and says he is the Manager, Asset Investment, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Joseph A. Karrasch

STATE OF OHIO)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Joseph A. Karrasch, this the 3rd day of December, 2013.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1, 2016

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**DIRECT TESTIMONY OF
JOSEPH KARRASCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Joseph A. Karrasch. I am employed by American Electric Power Service Corporation (AEPSC) as Manager – Asset Investments / Renewables. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor's degree in Mechanical Engineering from West Virginia University and a Master's degree in Business Administration from Ohio University. I have over twenty seven years of electric utility experience with AEP. I spent the first 22 years of my career with AEP working in several of AEP's power generation facilities. During my career in generation, I held a variety of positions including Performance Engineer, Maintenance Superintendent, Energy Production Manager, and General Plant Manager. In 2008, I took a position with AEPSC in my current role as Manager – Asset Investments / Renewables. As Manager – Asset Investments / Renewables, I have been involved in the evaluation of asset (generation plants) acquisition opportunities and have supported the management of AEP's and its subsidiaries' portfolio of Renewable Energy Purchase Agreements (REPAs). Besides managing the 250 MW request for proposals

("RFP") that is the subject of my testimony, I was the RFP Manager for renewable resources for several of AEP's affiliate operating companies.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER – ASSET INVESTMENTS / RENEWABLES?

A. As Manager – Asset Investments / Renewables, I am responsible for managing AEP's and its subsidiaries' portfolio of REPAs. I am one of the direct members of the team that structures and issues renewable energy RFPs, reviews and responds to questions posed by potential bidders, and evaluates proposals. I also participate in leading the negotiation and finalization of the REPAs with the winning bidder(s). In addition, I am responsible for coordinating a multi-discipline team in the evaluation of potential asset (generation facilities) acquisition opportunities when such opportunities arise.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided supplemental testimony on behalf of Kentucky Power Company ("Kentucky Power" or "Company") in Case No. 2012-00578. I also provided live testimony in that case.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the Company's March 28, 2013 RFP for up to 250 MW of long-term capacity and energy, to discuss both the conforming and non-conforming responses to this request, and to discuss the risks associated with a market purchase alternative that would be avoided or mitigated through the Company's proposed conversion of Big Sandy Unit 1 to natural gas.

IV. THE 250 MW RFP FOR CAPACITY AND ENERGY

Q. PLEASE BRIEFLY DESCRIBE THE 250 MW RFP FOR CAPACITY AND ENERGY.

A. The Company issued the RFP on March 28, 2013 as part of the process to determine the least-cost, reasonable solution for replacing the impending generation loss resulting from the anticipated retirement of its Big Sandy Unit 1 generation unit. The management and evaluation of this RFP was directed by select AEPSC personnel, who in turn were segregated into two groups – a Development Group and an Evaluation Group. The Development Group, of which I was a participating member, was responsible for the design, development, and management of the overall RFP process, while the Evaluation Group was responsible for evaluating the RFP Proposals and the BS1 Conversion cost as provided by the AEPSC Projects Group (Conversion Group). The Development and Evaluation Groups, and their members, were separate from the Conversion Group and any Affiliate of the Company that may have wished to participate in this RFP. The Company received responses to the RFP on June 11, 2013, the date identified within the RFP as the Proposal Due Date. [redacted]

Q. PLEASE DESCRIBE THE PROCESS THROUGH WHICH THE COMPANY NOTIFIED POTENTIAL BIDDERS OF ITS RFP.

A. The Company used a variety of communication channels to notify potentially interested parties that it was issuing the RFP. The Company published the RFP and associated schedule on its website at www.kentuckypower.com/go/rfp. The Company issued a press release which was also posted to its website, as well as providing notice to numerous trade publications regarding the issuance of its RFP. The Company also maintained an ongoing dialogue to respond to potential bidder's question through an on-line Q&A format, all of which was available for review by the prospective bidders on the Kentucky Power website. The RFP in its entirety has been included as **Exhibit JAK -1**.

Q. **DID THE RFP SOLICIT ONLY PROPOSALS FROM PROJECTS LOCATED WITHIN PJM?**

A. Yes. Section 2 of the RFP stated that AEPSC was requesting bids which would result in obtaining up to approximately 250 MW of PJM Generation Capacity Resources. In addition, energy delivered under a proposed purchase power agreement or tolling agreement was required to be scheduled in the PJM InSchedule system with a sink at the Big Sandy Unit 1 node. This scheduling requirement was included in the RFP to allow the Company to utilize any proposed Resource in a manner similar to a Product produced from the Company's Big Sandy Unit 1 resource. It also enabled the Company to compare Proposals to the BS1 Conversion cost.

Q. **WHY DID THE RFP SPECIFY THAT THE BID PROPOSALS MUST BE FROM A FACILITY THAT CAN BEGIN DELIVERY BY JUNE 1, 2015?**

A. The commencement of delivery specified by the RFP was based on the scheduled retirement of Big Sandy Unit 1. Failure to meet this delivery date could expose the Company to spot market energy risks and additional costs to meet its PJM FRR capacity obligation.

Q. **DOESN'T COMPANY WITNESS WALTON'S TESTIMONY PROJECT A JUNE 2016 IN-SERVICE DATE FOR THE CONVERTED BIG SANDY UNIT 1?**

A. Yes, the current construction schedule shows that the in-service date for a converted, natural-gas fired Big Sandy Unit 1 is June 2016. Consistent with the MATS Rule, Kentucky Power anticipates requesting an administrative one-year extension for units undertaking retrofit or replacement projects. Absent the conversion project (i.e. if it were to select a market alternative from the RFP), Kentucky Power would be required to retire Big Sandy Unit 1 by April 16, 2015.

Q. WHY IS IT IMPORTANT FOR THE BID PROPOSALS TO MEET ALL OF THE REQUIREMENTS SPECIFIED IN THE RFP?

A. Two of the major reasons the proposals needed to meet all of the requirements specified in the RFP were; (1) so the Company can meet the objective specified in the RFP, and (2) so that the bid proposals could be evaluated on an 'apples to apples' basis.

Q. PLEASE BREIFLY DESCRIBE THE CONFORMING RESPONSES TO THE RFP.

A. Section 4 of the RFP detailed the scope of the product the Company was soliciting through the RFP. Conforming responses to the RFP are those that met the requirements described in RFP. The Company received [redacted] in response to its solicitation. [redacted] Confidential **Exhibit JAK-2** provides a summary of the Conforming Bids and Non-Confirming Bids.

V. NON-CONFORMING RESPONSES

Q. PLEASE BRIEFLY DESCRIBE THE NON-CONFORMING RESPONSES TO THE RFP.

A. Non-conforming bids were defined as proposals the Company received that failed to meet one (or more) of the material product specifications outlined in the RFP. The Company received a total of [redacted] The non-conforming bids failed to comply with the requirements primarily as a result of [redacted]

Q. DID THE COMPANY CONTACT BIDDERS WITH NON-CONFORMING BIDS TO RESOLVE ANY BID DEFICIENCIES?

A. Yes. The Company contacted non-conforming bidders to see if the deficiencies in their bids could be resolved. The Company issued a series of requests for information to those bidders consisting of questions designed to determine whether the aspects of their bids that made them non-conforming could be addressed. In each instance, the bidders were unable to resolve their bid deficiencies via their responses to the requests for information.

Q. DID THE NON-CONFORMING BIDS [redacted]

A. [redacted]

Q. WAS THE NON-CONFORMING BIDDER PROPOSING [redacted]

[redacted]

A. [redacted]

Q. WHY DID THE RFP EXCLUDE PROJECTS LOCATED OUTSIDE OF THE PJM FOOTPRINT?

A. In order for a generating unit located outside of the PJM control area to provide Kentucky Power with capacity and energy, it must secure Long Term Firm (LTF) Transmission service from PJM. The process involves multiple studies and typically requires 18-24 months to complete. Once these studies are complete, an estimate for the amount and cost of upgrades would be provided by PJM to the proposed transmission customer quantifying the cost to grant transmission service. Depending on the extent of transmission upgrades required, the additional time required for construction of the interconnection facilities could exceed the original time required for the studies. The process and requirements for requesting LTF Transmission Service from PJM are set forth in PJM Manual 2 and PJM Manual 14A. **Exhibit JAK-3** provides PJM's overview of the process.

In addition to the PJM LTF Transmission Service, a transmission reservation to export the energy from [redacted] to PJM would also have to be obtained from [redacted] The process of securing all of the necessary firm transmission service would add additional steps, cost, and uncertainty to a bid proposal from a resource in [redacted]. There is no need for

Kentucky Power or its customers to assume such large risks when alternatives, without those risks, are available within PJM.

Q. DOES THE FACT [redacted]

A. [redacted]

Q. DID THE COMPANY RECEIVE ANY OTHER PROPOSALS AS PART OF THIS SOLICITATION?

A. Yes. EnerNOC, Inc. (EnerNOC), offered [redacted]

[redacted]

[redacted]

> [redacted]

[redacted]

[redacted]

[1] [redacted]

[redacted]

Q. FOLLOWING THE COMMISSION'S OCTOBER 7, 2013 ORDER APPROVING, WITH FOUR MODIFICATIONS ACCEPTED BY THE COMPANY, THE STIPULATION AND SETTLEMENT AGREEMENT AMONG KENTUCKY POWER, KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. AND SIERRA CLUB ("STIPULATION") IN CASE NO. 2012-00578 DID THE COMPANY ENTER INTO FURTHER NEGOTIATIONS WITH THE CONFORMING BIDDERS?

A. No. Paragraph 13 of the Stipulation as approved by the Commission required the Company to "exercise its option to terminate its March 28, 2013 Request for Proposals." On November 19, 2013, the Company notified the Bidders that it had exercised its option to terminate the RFP.

VI. RISKS ASSOCIATED WITH PROCEEDING WITH A MARKET ALTERNATIVE

Q. ARE THERE ANY RISKS WITH A MARKET ALTERNATIVE?

A. Yes, there are several risks that should be considered when evaluating a market alternative such as those provided in response to the 250 MW RFP. First, pursuing a market alternative introduces counterparty risk. Second, a market alternative introduces additional risk regarding the maintenance and unit condition of the facility supporting the purchase. And finally, there are jurisdictional considerations associated with a market alternative.

Q. PLEASE DESCRIBE SOME OF THE COUNTERPARTY RISKS ASSOCIATED WITH A MARKET ALTERNATIVE.

A. Relying on a market purchase of capacity and energy, whether through a Power Purchase Agreement or a Tolling Agreement, creates counterparty risk. Essentially, the Company and its customers must rely on a third-party to fulfill their obligations under the purchase or tolling agreement. The failure of the third-party to fulfill their obligation could result in significant volatility in rates. For example, if the third-party was forced to declare bankruptcy, or choose to default on the contract, then the Company and its customers could find themselves in the position of having to purchase more expensive replacement energy and capacity on the open market. Such reliance creates uncertainty and risks that are contrary to the interests of the Company and its customers.

Q. PLEASE DESCRIBE THE UNIT CONDITION RISK ASSOCIATED WITH A MARKET ALTERNATIVE.

A. Even with due diligence, the Company cannot and will not know as much about a third-party unit's condition and operational capabilities as it does about Big Sandy Unit 1. Under a market alternative, the company must rely on a third party to ensure that the generating facility is reliably maintained and operated. The potential risk and costs to the Company and its customers are similar to the counterparty risk I described previously. If the third party generating unit was unable to run as expected, then the Company and its customers could find themselves in the position of having to purchase more expensive replacement energy and capacity in the spot market.

Q. PLEASE DESCRIBE THE JURISDICTIONAL TREATMENT ASSOCIATED WITH A MARKET ALTERNATIVE.

A. A market alternative, using either a Power Purchase Agreement or a Tolling Agreement, is considered a wholesale market contract. As such, the contract falls under the jurisdiction of the FERC. Although the Kentucky Commission has the initial ability to review and approve certain longer-term purchase power agreements, its jurisdiction thereafter is significantly limited or non-existent. By contrast, the on-going regulation of a Company owned asset, such as the Company's proposed conversion of Big Sandy Unit 1, would continue to be regulated by the Kentucky Public Service Commission.

Q. ARE THE RISKS YOU HAVE DESCRIBED ABOVE UNIQUE TO THE SPECIFIC RESPONSES THE COMPANY RECEIVED IN THE 250 MW RFP?

A. No, they are not. The issues related to market alternatives are generally present to some degree in all market transactions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

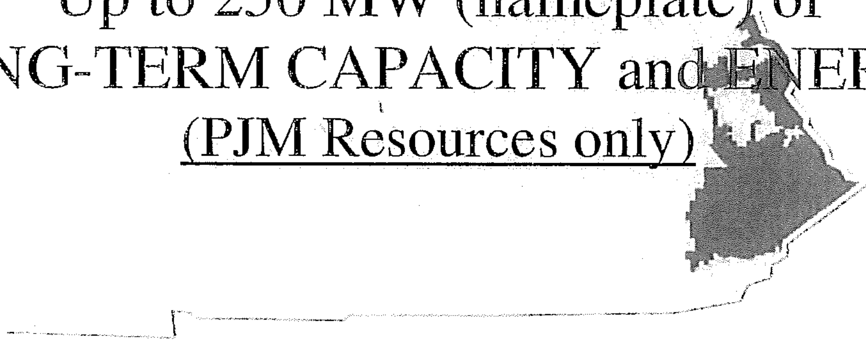
American Electric Power Service Corporation

as agent for

Kentucky Power Company

Request for Proposals

Up to 250 MW (nameplate) of
LONG-TERM CAPACITY and ENERGY
(PJM Resources only)



Capable of being on-line by June 1, 2015

Issued:
March 28, 2013

Web Address: http://www.kentuckypower.com/go/rfp/

Proposals Due:
June 11, 2013 (Columbus, OH)

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<u>Appendices</u>

Background

Kentucky Power Company (Company) is undertaking a process to determine the least, reasonable cost solution to replacing the impending generation loss anticipated with the retirement of its Big Sandy Unit 1 generation unit. Big Sandy Unit 1 is a 260 MW coal fired generating unit that went into service in 1963 and is currently scheduled for retirement in 2015. Big Sandy Unit 1 is located near Louisa, Kentucky and is within the PJM regional transmission organization.

The options available to the Company for the replacement of the Big Sandy Unit 1 generation capacity as a coal fired generation resource include:

- BS1 Conversion: converting Big Sandy Unit 1 to a natural gas fired generation unit (BS1 Conversion). The projected cost to convert Big Sandy Unit 1 will be developed by American Electric Power Service Corporation's (AEPSC) Projects, Controls & Construction group. (AEPSC Projects Group).

- PJM Capacity Resource Request for Proposals (RFP): issue an RFP for 250 MW of PJM Generation Capacity Resources.

The Company will use the proposals (Proposals) received as a result of the 250 MW RFP along with the BS1 Conversion cost estimate to determine the least, reasonable cost solution to replacing the Big Sandy Unit 1 capacity as a coal fired generating unit.

The evaluation of the RFP and BS1 Conversion is not a commitment to convert (BS1 Conversion) or purchase (RFP) and shall not bind the Company or any affiliates of the Company in any manner. The Company in its sole discretion will determine which direction, if any, it wishes to take with respect to replacing the Big Sandy Unit 1 coal fired generation capacity, energy, and ancillary services.

The management and evaluation of this RFP will be directed by select AEPSC personnel that have been categorized into two groups – a Development Group and an Evaluation Group. The Development Group will be responsible for the design, development, and management of the overall RFP process, while the Evaluation Group will be responsible for evaluating the RFP Proposals and the BS1 Conversion cost as provided by the AEPSC Projects Group. Members of the Development and Evaluation Groups are separate groups from the AEPSC Projects Group or any Affiliate of the Company that may wish to participate in this RFP.

AEPSC and the Company will ensure that the bids received in response to this RFP along with the BS1 Conversion cost are evaluated in a consistent, transparent, and impartial manner.

1. Company Information

1.1. American Electric Power (AEP) is one of the largest electric utilities in the United States, delivering electricity to more than 5.3 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and Texas). AEP's headquarters are in Columbus, Ohio. More information about AEP can be accessed by visiting www.aep.com.

1.2. Kentucky Power Company provides service to approximately 173,000 customers in all or part of 20 eastern Kentucky counties and is headquartered in Frankfort, KY. The Company has approximately 1,233 miles of transmission lines and 11,242 miles of distribution lines. Its distribution operations are based in Ashland with service centers in Pikeville and Hazard. The Company also has area offices in Paintsville and Whitesburg. More information about the Company can be accessed by visiting www.kentuckypower.com.

2. Introduction

2.1. American Electric Power Service Corporation, a subsidiary of AEP is administering this Request for Proposals (RFP) on behalf of Kentucky Power Company (Company). AEPSC is requesting bids which will result in obtaining up to approximately 250 MW of PJM Generation Capacity Resources[1] (Resources).

2.2. Resources bid into this RFP must be capable of being on-line by June 1, 2015 and able to supply a "Bundled Product" that includes Capacity (MW), Energy (MWh), and Ancillary Services if available.

2.3. AEPSC is requesting Proposals from parties desiring to sell a Bundled Product through a Power Purchase Agreement (PPA), Tolling Agreement (TA), an Asset Purchase Agreement (APA), or Other Proposal (OTH) as further defined in this RFP.

In addition, AEPSC will be accepting Proposals from demand-side management (DSM) and cost-effective energy efficiency (EE) resources.

[1] PJM Generation Capacity Resource is a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of the PJM Reliability Assurance Agreement. A Generation Resource may be an existing Generation Resource or a Planned Generation Resource.

2.4. Energy scheduled as a result of any PPA, TA, or OTH agreement shall be scheduled via a unilateral schedule in the PJM InSchedule system with a Sink at the Big Sandy Unit 1 Pnode as further described in Section 4.4.2 *(Note: this scheduling requirement will enable the Company to utilize any proposed Resource in a manner similar to a Product produced from the Company's Big Sandy Unit 1resource. In addition, it will enable the Company to compare Proposals to the BS1 Conversion cost as referenced in the Background of this RFP).*

2.5. For each Proposal, a Seller shall offer only one Base Proposal. Sellers are encouraged to provide the Company with a Base Proposal that reflects what it believes is their best pricing Proposal. At no point in the evaluation process will a Seller have the opportunity to unilaterally change its Proposal.

2.6. For each Base Proposal, a Seller is allowed to submit up to three alternatives (each an "Alternative Proposal"). Alternative Proposals may be for different bid sizes, term of contract (15 years or greater), or alternate contract terms and conditions. Proposals based on a different site, technology, contract type, or fuel supply arrangement from the Base Proposal must be submitted as a separate Proposal.

2.7. The Company will allow affiliates (Affiliates) of the Company to participate in this RFP. Affiliates will be required to follow all of the requirements of this RFP including the process outlined in Section 3 regarding questions. If an Affiliate's Proposal is offered, its Proposal (i) shall be submitted in the same format and under the same rules and (ii) shall be evaluated in the same manner as other Proposals submitted into this RFP.

2.8. The Company has established a web page (www.kentuckypower.com/go/rfp) at its website for this RFP. AEPSC and Kentucky Power Company reserve the right to amend this RFP at any time and at its sole discretion. Any amendments to this RFP will be posted at the Company web page.

2.9. This RFP is not a commitment to purchase and shall not bind the Company or any affiliates of the Company in any manner. The Company in their sole discretion will determine which Seller(s), if any, it wishes to engage in negotiations that may lead to a binding contract.

3. RFP Questions

3.1. Throughout the RFP process, interested parties may submit questions regarding this RFP to AEPSC via:

- instructions located at the Company's website established for this RFP (www.kentuckypower.com/go/rfp) or
- by emailing 2013KentuckyPowerRFP@aep.com.

3.2. Questions submitted as outlined in Section 3.1 above will be reviewed by AEPSC. Those questions (and answers) which AEPSC views in its sole discretion to be of benefit to other potential RFP participants will be posted on the Q&A portion of the website. Posted questions and answers will not identify the originator of the question.

4. <u>Scope</u>

The following sub-sections describe the scope of this RFP. All questions regarding the scope of this RFP should be submitted through the Company's website or RFP email address as outlined in Section 3.

4.1. <u>Product</u> – the Company is seeking a low cost Bundled Product from PJM Generation Capacity Resources that includes the following.

- 4.1.1. Capacity (MW)
- 4.1.2. Energy (MWh)
- 4.1.3. Ancillary Services (if available)
- 4.1.4. Environmental Attributes[2] (if available)

4.2. <u>Quantity</u> – the Company is seeking Proposals for up to 250 MW, however, may procure more or less than 250 MW, and may aggregate Bundled Products from multiple Sellers to meet its needs, or select no offers at all.

- 4.2.1. Proposals shall have a minimum nameplate capacity size of 50 MW, with the exception of DSM / EE Proposals.
- 4.2.2. DSM and EE Proposals shall have a minimum size of 1 MW.

4.3. <u>Delivery Period</u> – The delivery of Capacity and Energy should begin no earlier than June 1, 2015.

- 4.3.1. Delivery period start dates later than June 1, 2015 will be accepted, however, <u>Seller will</u> be required to supply to the Company the PJM Capacity value for the period between June 1, 2015 and the actual delivery start period.
- 4.3.2. <u>All Base Proposals, with the exception of DSM/EE Proposals, shall have a term of 15 years.</u> Base Proposals with terms other than 15 years will be considered non-conforming and rejected from the RFP process. Sellers may provide terms of greater than 15 years within their Alternative Proposals.
- 4.3.3. DSM / EE Proposals shall have a minimum term of 5 years.

4.4. <u>Energy Delivery (for PPA, TA, and OTH Proposals)</u>

- 4.4.1. The Company and the Seller(s) will bilaterally establish and confirm a contract in PJM's InSchedule system (Contract) related to any agreement between the Company and the Seller.
- 4.4.2. The Contract will have the following key attributes:

---

[2] Environmental Attributes include, but are not limited to any associated renewable energy credits (RECs) and any other current or future environmental attributes, including any greenhouse gas emission reductions associated with the quantity contracted from a facility.

4.4.2.1. the "Schedule Confirmation Type" will be "Unilateral Buyer," such that the Company will have unilateral schedule confirmation rights for all schedules between the parties;

4.4.2.2. the "Sink" will be the Point of Delivery as defined in the table below;

Point of Delivery	
Pnode ID name	BIGSANDY
Pnode ID number	40243783
Location	Louisa, KY
County	Lawrence

4.4.2.3. the "Service Type" will be "Internal Bilateral Transaction".

4.5. <u>Interconnection</u>

4.5.1. The Point of Interconnection shall be the Facility's interconnection point with the PJM system.

4.5.2. All Proposals, at a minimum, must have completed the PJM Feasibility Study phase of the interconnection request process with PJM.

4.5.3. The Seller is responsible for all costs associated with transmission interconnections and system upgrades as required by PJM and the transmission operator.

4.5.4. The Seller is responsible for following the established PJM and transmission operator policies and procedures that are in effect regarding facility interconnection and operation associated with a utility's transmission system.

4.6. <u>Proposal Types</u> - the Company is interested in executing a contract ("Supply Agreement") from one or more of the following proposal types

4.6.1. Power Purchase Agreements ("PPA")

4.6.2. Tolling Agreements ("TA") – Seller pricing shall include the option of Seller providing the fuel, however, the Proposal shall also include an option where the Company will supply the fuel to the Resource.

4.6.3. Asset Purchase Agreements ("APA") – The Company will accept Proposals for assets that are currently in-service or will be in-service prior to June 1, 2015. The Company will not accept Proposals for partially built assets.

4.6.4. Other Proposals ("OTH") – Other Proposals are other power supplies or arrangements that do not fall into a PPA, TA, APA or DSM/EE category

4.6.5. Demand-side management ("DSM") or Cost-effective energy efficiency resources ("EE")

4.7. <u>Pricing</u>

4.7.1. Seller shall use Appendix A and any other attachments as needed to fully articulate the pricing of its Proposal.

4.7.2. Seller shall provide a summary of its essential terms and conditions associated with Seller's Proposal and pricing.

4.7.3. Prices must be firm, representing best and final data and quoted in U.S. dollars.

4.7.4. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

4.7.5. Pricing to include all Ancillary Service costs, taxes and other fees necessary for delivery of the Energy to the Point of Delivery as applicable.

4.7.6. All costs associated with interconnections and transmission, including any system upgrades, as required by PJM up to the Point of Delivery shall be included in the Seller's pricing where appropriate under current FERC orders and rulings.

4.7.7. DSM / EE Proposals: Seller shall fully describe in Appendix D or other attachment the pricing associated with its Proposal.

4.8. Ancillary Services

4.8.1. Under a Supply Agreement, the Company prefers to have the unrestricted right to utilize all Ancillary Services associated with generation being offered by the Seller. In addition, the Company desires to have the unrestricted rights to any future Ancillary Services defined by the industry and capable of being provided by the generation capacity being offered.

4.8.2. The Seller shall describe the Ancillary Service capability of the Facility (Regulation, Synchronized Reserve, Black Start Service, DA Scheduling Reserve, etc.)

4.8.3. All Ancillary Services must be provided in accordance with the requirements of PJM and the transmission operator.

4.8.4. The Ancillary Services that would be available to the Company should not be limited to those defined in this section.

4.8.5. In the case where the Company purchases only part of the generation capacity from a unit, system or facility, then the Company desires to have unrestricted rights to Ancillary Services on a prorated basis.

4.9. DSM / EE Proposals must be from resources located within the Company's service area.

5. RFP Schedule

5.1. The following schedule and deadlines apply to this RFP. AEPSC and the Company reserve the right to revise this schedule at any time and at its sole discretion. Any revisions to the schedule will be posted to the RFP website.

5.2. All Proposals must be complete in all material respects and be received no later than 4 p.m. EST on Tuesday, June 11th at the AEPSC Columbus, OH location as defined in Section 6 of this RFP.

RFP Issued	Thursday, March 28, 2013
Confidentiality Agreements	Friday, May 24, 2013
Proposals Due Date	Tuesday, June 11, 2013
RFP Short-List Identified	Friday, July 12, 2013
Final Decision (Recommended)	tbd

6. Proposal Submittal

One hard copy and one electronic copy on CD of the Proposal(s) shall be submitted by the Proposal Due Date as outlined in Section 5 of this RFP to:

American Electric Power Service Corporation
Kentucky Power Company RFP Administrator
155 W. Nationwide Blvd
Columbus, OH 43215

7. Key Terms and Conditions

For a Supply Agreement, the Seller's Proposal should include, where applicable to the Seller's Proposal, the following terms and conditions, among other things:

7.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, operations and maintenance costs, as applicable.

7.2. Pricing shall include all pricing and terms for Capacity, associated Energy, and Ancillary Services.

7.3. Seller will guarantee the annual and seasonal availability.

7.4. Seller will be responsible for any and all compliance related costs and fines (environmental, NERC, FERC, PJM, etc) incurred due to the non-compliance of the asset(s) designated to supply Capacity, Energy, and Ancillary Services to the Company.

7.5. Seller shall be responsible for ALL reporting requirements under NERC, PJM, etc.

7.6. Seller shall be responsible for offering Company's Capacity, Energy and Ancillary Services into the PJM market.

7.7. For the sale of generation capacity and energy to the Company under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold.

7.8. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller.

7.9. Financial Capability

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

7.9.2. Upon execution of a Supply Agreement, Seller will be required to provide Security in the form of an irrevocable standby letter of credit (LOC), cash, or a corporate guaranty from a credit worthy entity, to protect the Company's customers in the event of default by the Seller. The amount and terms of the Security will be subject to approval by the Company based upon the Company's standards.

8. Proposal Content

8.1. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. Seller shall use Appendix C as a reference of the material required to be submitted with Seller's Proposal.

8.2. The Company reserves the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Company's internal evaluation of cost, risk, and value.

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

9. Treatment of Proposals

9.1. The Company reserves the right, without qualification, to select or reject any or all Proposals and to waive any formality, technicality, requirement, or irregularity in the Proposals received.

9.2. The completed Appendices and any supplement information submitted by the Seller may be utilized in any filings with regulatory agencies related to this RFP.

9.3. The Company reserves the right to solicit additional Proposals, to modify the RFP or request additional information, as necessary, to complete its evaluation of the Proposals received.

9.4. Sellers who submit Proposals do so without recourse against the Company for either rejection by the Company or failure to execute an agreement for purchase of Capacity and/or energy for any reason.

10. RFP Proposal Evaluation

10.1. Initial Review
Proposals will be thoroughly reviewed and assessed to ensure that each meets ALL applicable content requirements as described in Section 8 – Proposal Content. Proposals that meet all the requirements (as applicable) of the RFP shall be considered conforming. Proposals will be deemed non-conforming if they do not meet all the requirements specified in the RFP and will be rejected. During the initial screening process, the Company reserves the right, but is not obligated, to contact Seller(s) to clarify Proposal terms or to request additional information.

10.2. Evaluation
The Company will use a multi-stage evaluation process to review Proposals. The evaluation process followed will depend on the number and nature of the Proposals received. The evaluation process will consider all applicable factors including, but not limited to, the following to determine the reasonableness of the Proposal and the projected least, reasonable cost:

- Terms of the proposal
- Exceptions to the terms and conditions as outlined in this RFP
- Proposal Pricing
- Impact of Proposal to Company's balance sheet and credit rating
- Seller's creditworthiness and experience
- Proposed date of commercial operation (on-line)
- Status of interconnection process with PJM
- Project capacity
- Regulatory considerations
- Development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission;

At the conclusion of the evaluation process, a Short-list of Proposals will be identified for further evaluation and comparison to the BS1 Conversion cost as referenced in the Background section (page 3) of this RFP. If the Company determines that a Proposal(s) is in the best interest of the Company and its customers, the Company will enter into negotiations which may lead to the execution of a definitive agreement(s). Sellers of Proposals that are not selected to the Short-list will be notified that their Proposals were not selected to the Short-list.

10.3. Seller agrees to cooperate, to the fullest extent necessary, to obtain any and all State, Federal, or other regulatory approvals required for the effectiveness of a transaction.

10.4. Execution of any agreement shall also be dependent upon AEPSC and Kentucky Power Company obtaining sufficient assurance that the product purchased pursuant to the any agreement will be recognized for full recovery in the rates charged to its jurisdictional customers. The determination of what constitutes "sufficient assurance" shall be at the sole discretion and judgment of AEPSC and Kentucky Power Company.

11. Confidentiality

11.1. Attached as Appendix F is the Company's Form Confidentiality Agreement (CA). If Seller elects, they may complete the CA and forward electronically to 2013KentuckyPowerRFP@aep.com for execution by the Company.

11.2. AEPSC will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all bids submitted. Sellers should clearly identify each page of information considered to be confidential or proprietary. AEPSC reserves the right to release any Proposals to agents or consultants for purposes of Proposal evaluation. AEPSC's disclosure policies and standards will automatically bind such agents or consultants. Regardless of the confidentiality, all such information may be subject to review by the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. Under such circumstances, AEPSC will make all reasonable efforts to protect Seller's confidential information.

12. Seller's Responsibilities

12.1. Proposals and bid pricing must be valid for at least 120 days after the Proposal Due Date, upon which time Proposals shall expire unless the Seller has been notified and selected as a Short-listed Seller or as a final award recipient.

12.2. It is the Seller's responsibility to submit all requested material by the deadlines specified in this RFP. The Seller should make its Proposal as comprehensive as possible so that the Company may make a definitive and final evaluation of the Proposal's benefits to its customers without further contact with the Seller.

12.3. Sellers are responsible for the timely completion of the project and are required to submit proof of their financial and technical wherewithal to ensure the successful completion of the project.

12.4. The Company shall not be liable for any expenses Sellers incur in connection with the preparation and submission of a Proposal and/or any subsequent negotiations. The Company will not reimburse Sellers for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Company at its sole discretions.

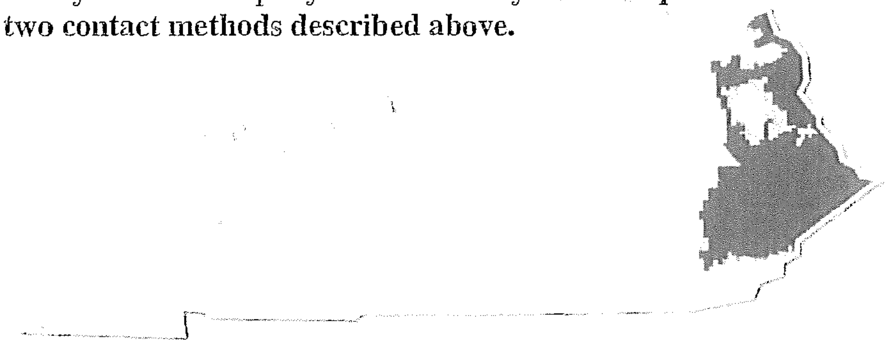
13. Contacts

All correspondences and questions regarding this RFP must be:

1. directed to the "Questions" section of the website established for this RFP (www.kentuckypower.com/go/rfp) or

2. by emailing 2013KentuckyPowerRFP@aep.com.

NOTE: Sellers or parties interested in participating in this RFP shall not contact the Kentucky Power Company offices directly. ALL inquiries must be submitted via the two contact methods described above.



Appendix A

Company Information

Seller (Company):
Contact Name:
Contact Title:
Address:
City: State: Zip Code:
Work Phone: Cell Phone:
Email Address:

General Project Information

Project Name / Description:				
Resource Type : *(e.g. NG Simple Cycle, Combined Cycle, Pulverized Coal, CFB, Wind, Hydro, DSM, EE, etc.):*				
Fuel Type (Primary / Secondary) :				
Project Location:				
Estimated On-line Date:	Expected Annual Production (MWh):			
Project Capacity Values, MW	Nameplate Rating	Winter Rating	Summer Rating	PJM Capacity Value
Is proposed MW the entire facility capacity (Y / N); If no, then how large is the entire facility (MW)?				

PJM Interconnection Summary

Feasibility Study Complete (Y/N): PJM Queue #:
Interconnecting Utility / Location:

Substation:	Interconnection Voltage:
PJM Interconnection Status (describe):	

Proposal Type (check one)				
PPA	TA	OTH	DSM	EE

Pricing

Sellers shall provide a detailed written description of all pricing formulas including a detailed description of all sub-components. As noted in the RFP, the Company requires a Base Proposal, however the Company will allow Sellers to include up to three other Alternatives in their Proposal. If Seller elects to offer Alternatives, then Seller shall submit separate Proposal Pricing Sheets for each Alternative.

The following requirements for each of the Proposal Types shall be used as a guide. It is the Sellers responsibility to clearly articulate in this Appendix and any associated attachments the pricing component to the Seller's proposal.

PPA Proposals

Project Name: ______________________________

Term: [__________] to [__________]

Contract Quantity: [__________] MW of Capacity and Energy

Capacity Charge: [__________] $ / kw-month, define any annual price escalation

Heat Rate: [__________] Btu / kWh, provide heat rates at all dispatch points

Variable O&M: [__________] $ / MWh, define any annual price escalation

Fuel Cost: (Fuel Cost Index Name) or [ ] $ / MMBtu, provide a fuel price index and any adders, escalation or adjustments to the index to be used to price fuel delivered to the Facility, or provide the actual cost of fuel delivered to the facility.

Energy Payment: [__________] $ / MWh, define any annual price escalation

Start-up Payment: [__________]: $ / start

Other Operating Related Charges: [Define cost and parameters for charges]

TA Proposals

Project Name: ____________________________________

Term: [_________] to [_________]

Contract Quantity: [_______] MW of Capacity and Energy

Capacity Charge: [_________] $ / kw-month, define any annual price escalation

Heat Rate: [__________] Btu / kWh, provide heat rates at all dispatch points

Variable O&M: [_________] $ / MWh, define any annual price escalation

Fuel Cost: (Fuel Index Name) or [ ] $ / MMBtu, provide a fuel price index and any adders, escalation or adjustments to the index to be used to price fuel delivered to the Facility, or provide the actual cost of fuel delivered to the Facility. For Tolling Agreements, Kentucky Power Company reserves the right to purchase and supply the fuel to the Facility itself.

Start-up Payment: [__________]: $ / start

Other Operating Related Charges: [Define cost and parameters for charges]

Asset Purchase Agreements

Project Name:

Nameplate Capacity:

Sale Price, $M: [ ]

Proposed Asset Transfer Date: [ ]

Other Proposals

For "Pricing Terms" for all non-PPA proposals, Bidder shall provide these terms on a separate sheet providing a complete detail of such terms.

Appendix B

Operating Characteristics

Heat Rate – Summer (Btu /kwh at all loading points allowed by the Proposal)	
Heat Rate – Winter (Btu /kwh at all loading points allowed by the Proposal)	
Summer Capacity – Max (MW)	
Summer Capacity – Min (MW) or at all loading points allowed by the Proposal	
Winter Capacity – Max (MW)	
Winter Capacity – Min (MW) or at all load points allowed by the Proposal	
Output (MW) in 10 minutes from Start	
Ramp Rate (MW / min) – Normal	
Ramp Rate (MW / min) – Maximum	
Start-up time (hot) to minimum capability	
Start-up time (hot) to maximum capability	
Start-up time (warm) to minimum capability	
Start-up time (warm) to maximum capability	
Start-up time (cold) to minimum capability	
Start-up time (cold) to maximum capability	
Auxiliary Load (at all loading points allowed by the Proposal)	
Minimum run time	
Minimum down-time	
Forced Outage Rate	
Scheduled Outage Rate	
Annual Availability (%)	
Production Constraints:	
Ancillary Services (describe):	

Air Emissions

Emissions	Primary Fuel		Secondary Fuel	
	Lb / MWh	Tons / Year	Lb / MWh	Tons / Year
Sulfur Dioxide				
Nitrogen Oxide				
Carbon Monoxide				
Carbon Dioxide				
Mercury				
Particulates (PM / PM 10)				
Volatile Organic Compounds				

Please note assumption used in completing table above (example – MWh):

Assumptions:

Appendix C

Proposal Requirements

1. An executive summary of the bid's characteristics and timeline, including any unique aspects and benefits.
2. Seller shall complete Appendix A as applicable.
3. Seller shall complete Appendix B as applicable.
4. Sellers with DSM/EE Proposals shall complete Appendix D. DSM/EE Proposal documents shall be limited to 30 pages. Additional information may be submitted electronically (eg. CD, memory stick).
5. Seller shall fully describe any exceptions it takes towards any terms and conditions as described in Section 7 or other parts of this RFP.
6. Experience and References
    a. Provide a general description of the Seller's background and experience in utility scale power projects similar to its proposal, including any affiliated companies, holding companies, subsidiaries or predecessor companies presently or in the past engaged in developing energy power supply projects.
    b. Provide three (3) or more references from projects where the bidder, or any of its affiliates, has completed the development and construction of a power project similar to the one proposed to the Companies. If the bidder has fewer than three projects, it shall provide as many references as possible.
7. Seller shall provide a comprehensive narrative of the development status of any new generation project intended to be used to meet Seller's obligations to the Company. Seller's narrative shall include the following.
    a. Key project participants including owners, operators, engineer / contractors, fuel suppliers.
    b. Status of engineering and design work.
    c. A comprehensive development and construction schedule.
    d. A listing of all required permits and governmental approvals and their status.
    e. A listing of all required electric interconnection and or transmission agreements and their status.
    f. A financing plan.
    g. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.
8. Seller shall provide copies of all PJM Interconnection studies. In addition, Seller shall provide the following:

a. Impedance of the generator step-up transformer.

b. Transient and sub-transient characteristics of the generator.

9. Project Site

a. Seller shall provide proof or status of ownership or control of site.

b. Seller shall provide a summary describing whether the site has been assessed for environmental contamination, has any known environmental issues, and if a Phase 1 environmental assessment has been completed.

c. Has the site been assessed for environmental contamination? Describe any known environmental issues?

d. Describe status of all required permits.

e. If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.

10. Legal Proceedings

a. List all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been or are engaged that could affect bidder's performance of its bid.

b. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.

11. Technology / Equipment

a. Technology employed (combined cycle, pulverized coal, CFB, etc.)

b. Provide details regarding the technology selected, major equipment manufacturer identified, status of equipment purchases.

12. Existing Facilities (including **Asset Purchase Agreements**) - For existing facilities, at a minimum, provide the following information for each of the last 5 years of operating history;

a. Energy generated

b. Capacity factor

c. Number of start-ups

d. Average heat rate

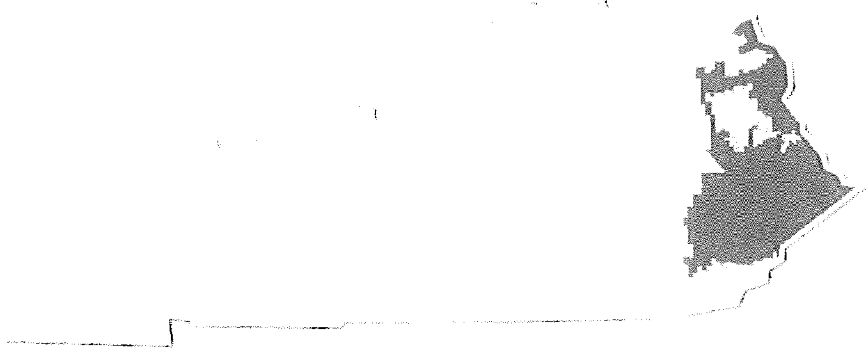
e. On-Peak availability

f. Fixed O&M Costs

g. Variable O&M Costs

h. Capital expenditures

13. Sellers of assets (Asset Purchase Agreements) shall provide a description of the facility's major equipment
14. Seller shall provide a copy of air permit or permit application(s) if available.
15. Seller shall provide a summary of the timing and status of all permit applications including water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.
16. Seller shall provide its operations plan – describe the entity who will be performing operations and maintenance of the facility
17. Seller shall provide its fuel supply plan.
18. Subsidies – Bidders must indicate if their proposal is dependent upon any existing state or federal tax credit or grant program and expiration of said program.
19. Maintenance Outages
    a. Seller shall describe the required annual (routine) maintenance outage schedule and associated tasks.
    b. Seller shall describe major outages schedules, general scope and frequency



Appendix D

DSM / EE - Proposal Requirements

Company Information

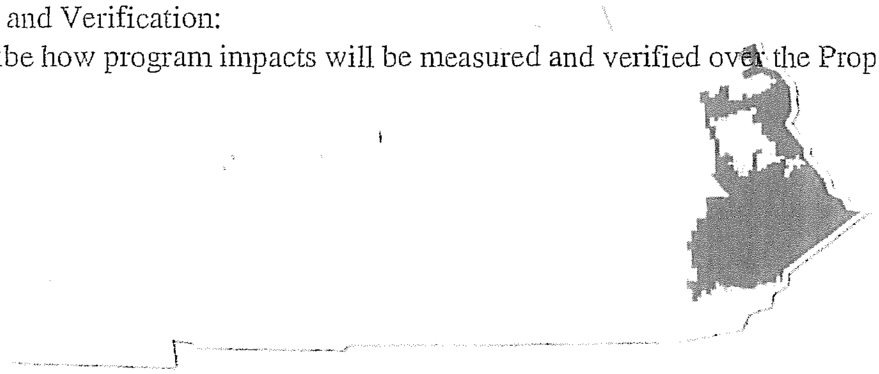
Seller (Company):		
Contact Name:		
Contact Title:		
Address:		
City:	State:	Zip Code:
Work Phone:	Cell Phone:	
Email Address:		

Seller's with DSM and EE Proposals shall fully describe below or on a separate attachment the resource being offered, size/quantity, term, pricing, and essential terms and conditions associated with their offering. DSM/EE Proposal documents shall be limited to 30 pages. Additional information may be submitted electronically (eg. CD, memory stick).

General Project Information

Project Name / Description:

Describe End-uses Impacts: • Provide monthly projected peak and energy impacts over the Proposal Term • Provide hourly reduction load shapes over the Proposal Term by end-use and aggregated for the Proposal • Provide measure life and any degradation in peak and energy impacts over the Proposal Term
Measurement and Verification: • Describe how program impacts will be measured and verified over the Proposal Term



Appendix E

Bidder's Credit-Related Information

Full Legal Name of the Bidder:
Type of Organization (Corporation, Partnership, etc.):
Bidder's % Ownership in Proposed Project:
Full Legal Name(s) of Parent Corporation: 1. 2. 3.
Entity Providing Credit Support on Behalf of Bidder (if applicable): Name: Address: City: Zip Code:
Type of Relationship:
Current Senior Unsecured Debt Rating: 1. S&P: 2. Moodys:
Bank References & Name of Institution:
Bank Contact: Name: Title: Address: City: Zip Code: Phone Number:
Legal Proceedings: As a separate attachment, please list all lawsuits, regulatory proceedings, or arbitration in which the Bidder or its affiliates or predecessors have been or are engaged that could affect the Bidder's performance of its bid. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.
Financial Statements: Please provide copies of the Annual Reports for the three most recent fiscal years and quarterly reports for the most recent quarter ended, if available. If available electronically, please provide link:

Appendix F

Mutual Confidentiality Agreement

Email to: 2013KentuckyPowerRFP@aep.com
American Electric Power Service Corporation
155 West Nationwide Boulevard
Suite 500
Columbus, OH 43215
Fax: (614) 583-1611

Due: Friday, May 24, 2013

This Mutual Confidentiality Agreement ("Agreement") dated as of ____________, 2013 ("Effective Date") is made and entered into by and between American Electric Power Service Corporation ("AEPSC"), as agent for Kentucky Power Company, and *insert full legal name*, a(n) *insert state of formation insert type of company* ("Bidder").

Recitals:

I. Bidder is or is considering submitting a proposal (the "Proposal") in response to a Request for Proposals (the "RFP") issued by AEPSC for energy, capacity, and ancillary services as described in the RFP. If submitted, the Proposal will become the property of AEPSC and shall be held confidential under terms of the RFP.

II. It may become desirable that AEPSC and Bidder exchange other confidential information pursuant to questions, responses or other communications that are not contained in the Proposal and which the parties desire to protect as confidential.

III. In addition, if the Proposal, if submitted, is selected by AEPSC, then Bidder and AEPSC will negotiate about a proposed agreement between AEPSC and Bidder to implement the Proposal (the "Proposed Agreement"). Bidder and AEPSC want to keep all negotiations concerning the Proposed Agreement, including the Proposed Agreement itself and all drafts of the Proposed Agreement, confidential.

IV. The parties are willing to exchange such confidential information pursuant to the terms of this Agreement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the parties agree as follows:

Section 1. Definitions.

1.1. (a) "Confidential Information" means any information that is disclosed by the Disclosing Party to the Receiving Party or its Representatives in connection with the RFP or any Proposed Agreement (collectively, the "Transaction"), whether before or after the date hereof and irrespective of the format in which the information is provided. For avoidance of doubt, "Confidential Information" includes:

(i) Written information or machine-readable data, including questions, responses or communications in connection with AEPSC's RFP or any Proposed Agreement, notes, reports, assessments, specifications, drawings, financial statements and projections, software and databases, customer information, sales and marketing strategies, and any other written information or machine-readable data;

(ii) Orally conveyed information, including but not limited to demonstrations that are directly related to written or other tangible Confidential Information;

(iii) Any hardware, including but not limited to samples, devices and any other physical embodiments delivered to the Receiving Party;

(iv) Any Evaluation Material; or

(v) The existence of this Agreement, the terms of this Agreement and any Proposed Agreement, including all drafts of the Proposed Agreement and all negotiations concerning the Proposed Agreement, that may arise stemming from the Bidder's Proposal.

(b) "Confidential Information" does not include information which:

(i) is, or subsequent to disclosure becomes, part of the public domain through no fault of the Receiving Party;

(ii) is lawfully disclosed to the Receiving Party by a third party which, to the knowledge of the Receiving Party, does not have a confidentiality obligation to the Disclosing Party;

(iii) was lawfully in the possession of the Receiving Party prior to disclosure by the Disclosing Party; or

(iv) is lawfully and independently developed by the Receiving Party without use of the Confidential Information disclosed by the Disclosing Party.

1.2. "Disclosing Party" means the party disclosing Confidential Information.

1.3. "Evaluation Material" means notes, reports or other documents which reflect, interpret, evaluate, include or are derived from the Confidential Information.

1.4. "Receiving Party" means the party receiving Confidential Information.

1.5. "Representatives" means a party's employees, officers, directors, attorneys, accountants, consultants, advisors and agents (including potential lenders, equity partners, underwriters, or other parties involved in the Transaction for the party), and the party's affiliates and the employees, officers, directors, attorneys, accountants, consultants, advisors and agents thereof.

Section 2. Confidentiality. Except as provided in Section 5, the parties hereby agree that the Confidential Information will be kept confidential during the term of this Agreement. The parties also agree that without the prior written consent of the Disclosing Party, the Confidential Information will not be disclosed by the Receiving Party, in whole or in part, to any other person except as provided herein. Each party shall use the same care in protecting the other's Confidential Information as it uses to protect its own confidential information, provided that neither party shall use less than reasonable efforts to protect the other's Confidential Information. Notwithstanding the foregoing, the Receiving Party may (a) disclose Confidential Information to its Representatives whose access is necessary to conduct the evaluations and negotiations in connection with the Transaction, or for supervisory, regulatory or similar purposes, and who have been informed of and have agreed to abide by the confidentiality restrictions contained in this Agreement and (b) make a limited number of copies of the Confidential Information in order for the Receiving Party to adequately use the Confidential Information subject to the terms and conditions of this Agreement. Each party agrees to be responsible for the actions, uses and disclosures of any of its Representatives in accordance with the terms and restrictions of this Agreement.

Section 3. Ownership and Use of Confidential Information. All Confidential Information (except Evaluation Material) shall remain the property of the Disclosing Party. No license or other rights under any patents, trademarks, copyrights or other proprietary rights is granted or implied by the disclosure of the Confidential Information. Neither party shall use the Confidential Information for any purpose other than for evaluation of and negotiations relating to the Transaction.

Section 4. Disposition of Confidential Information. The Receiving Party, upon written request from the Disclosing Party, shall promptly return or destroy all Confidential Information in its possession; provided, however, with respect to Evaluation Materials, the Receiving Party may at its discretion destroy such Evaluation Material. If requested by the Disclosing Party, the Receiving Party shall provide the Disclosing Party with a certification that all Confidential Information and Evaluation Material has either been returned or destroyed, as appropriate. Notwithstanding the foregoing, the Receiving Party may retain one copy of the Confidential Information solely for archival purposes and for the purpose of demonstrating compliance with this Agreement. The return or destruction of the

Confidential Information shall not extinguish any rights or obligations under this Agreement with respect to the Confidential Information.

Section 5. Legally Required Disclosures. If the Receiving Party or its Representatives become subject to a bona fide requirement or request by any regulatory, governmental, judicial or supervisory authority (by subpoena, oral deposition, interrogatories, request for production of documents, civil investigative demand, administrative order or otherwise), to disclose any of the Confidential Information, or if such disclosure is necessary in order to obtain or maintain regulatory or governmental approvals, applications or exemptions, the Receiving Party will provide the Disclosing Party with as much advance notice as and to the extent as permitted and practicable to afford the opportunity to seek an appropriate protective order or other appropriate remedy to prevent the disclosure. The Receiving Party or any of its Representatives being compelled to disclose such Confidential Information will reasonably cooperate with the Disclosing Party, at its expense, to enable the Disclosing Party to obtain a protective order or other reliable assurance that confidential treatment will be accorded the same (e.g. confidentiality agreement). If such protective order or other appropriate remedy (e.g. confidentiality agreement) is not obtained, the Receiving Party or any of its Representatives being compelled to disclose such Confidential Information may disclose the information without liability hereunder provided that the party may only furnish that portion of the Confidential Information which is legally required or necessary.

Section 6. Term. If the Bidder's Proposal and/or related negotiations do not result in a final agreement, then this Agreement is effective for two (2) years from the Effective Date stated above. If the negotiations result in a final agreement, then this Agreement is effective until two (2) years after the termination of the final agreement.

Section 7. No Warranties. The Disclosing Party makes no representations or warranties as to the reliability, accuracy or completeness of the Confidential Information. The Disclosing Party shall not be subject to any liability to the Receiving Party based on the Receiving Party's use of the Confidential Information.

Section 8. Remedies. The parties acknowledge that improper or unauthorized use or disclosure of Confidential Information could cause irreparable harm to the Disclosing Party and that monetary damages would not be an adequate remedy for a breach of this Agreement. In the event of any breach or threatened breach of this Agreement, the non-breaching party shall be entitled to pursue injunctive and other equitable relief, and the breaching party agrees to waive any requirement for the posting of a bond in connection with such remedy. Such injunctive and equitable relief shall not be deemed to be the exclusive remedy for a breach of this Agreement, but shall be in addition to all other available remedies. In no event shall either party be liable to the other for any incidental, indirect, special, punitive or consequential damages (including without limitation damages for lost profits).

Section 9. Relationship of Parties. Neither party shall have any obligation to commence or continue discussions or negotiations, to exchange any Confidential Information, to reach or execute any agreement with the other party, to refrain from engaging at any time in any business whatsoever, or to refrain from entering into or continuing any discussions, negotiations or agreements at any time with any third party, until each party executes a definitive agreement. Until such definitive agreement is executed, neither party shall have any liability to the other party with respect to the Transaction except as set forth in this Agreement. Neither party shall have any liability to the other party in the event that, for any reason whatsoever, no such definitive agreement is executed.

Section 10. General.

10.1 Governing Law. This Agreement shall be construed and enforced in accordance with the laws of the State of Kentucky.

10.2 Entire Agreement. This Agreement constitutes the entire Agreement between the parties, supersedes any prior understandings or representations relating to the confidential treatment of the Confidential Information, and shall not be modified except by a written agreement signed by both parties.

10.3 Assignability. This Agreement may not be assigned by either party without the prior written consent of the other party; provided, however, that AEPSC may assign this Agreement to one or more of its affiliated companies.

10.4 Severability. All provisions of this Agreement are severable, and the unenforceability of any of the provisions of this Agreement shall not affect the validity or enforceability of the remaining provisions of this Agreement.

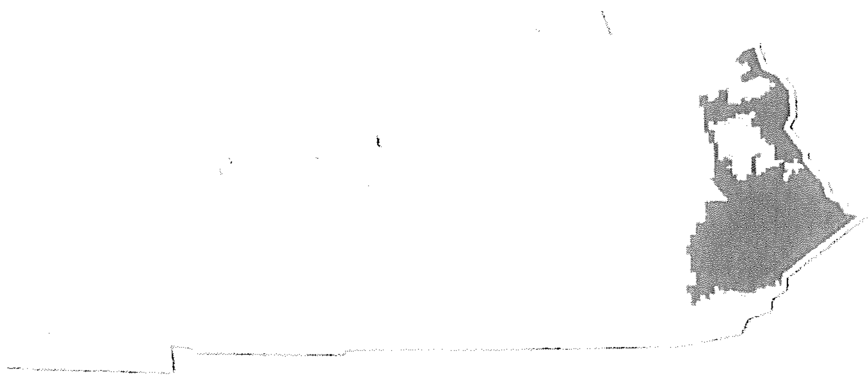
10.5 No Waiver. Failure of either party to insist upon strict performance of any of the terms and conditions shall not be deemed to be a waiver of those terms and conditions.

10.6 Counterparts and Faxed Signatures. This Agreement may be executed in counterparts, and in the absence of an original signature, faxed signatures will be considered the equivalent of an original signature.

10.7 Notices. Notices shall be in writing and shall be sent to the addresses listed below, either by personal delivery, by the U.S. Mail, overnight mail, fax or other similar means. All notices shall be effective upon receipt.

The parties have signed this Agreement effective as of the later signature date set forth below.

SIGNATURES ON FOLLOWING PAGE



The parties have signed this Agreement effective as of the later signature date set forth below.

American Electric Power Service Corporation, as agent for Kentucky Power Company

By:______________________________

Print Name:______________________

Title: ___________________________

Date:____________________________

[BIDDER: insert full legal name]

By:__________________________________

Print Name:__________________________

Title:_________________________________

Date:_________________________________

Bidder Address:

____

____

Attn:__________________________________

EXHIBIT JAK-2

CONFIDENTIAL IN ITS ENTIRETY

Long Term Firm (LTF) Transmission Service Requests - Quick Guide

Note: This process is modeling a typical transmission service request flow and can vary based on actual requests. This Quick Guide is for reference only and is not intended to supersede any PJM Tariff, Manual, or Business Practice.

1. Customer requests service on OASIS. This will be either Point-to-Point (year-FIRM) or Network Designated (year-NETWK_EXT_DESIGNATED). FERC Order 890 requires the term at least 5 years for rollover/renewal rights.
   - P-to-P is used for importing/exporting between a Point of Receipt (POR) and a Point of Delivery (POD).
   - Network is used for Designated Network Resources (DNR) or Network Native Load (NNL) or RPM capacity.
2. PJM has 30 days from the queue date of the request to send an Initial Study Agreement to the customer.
3. Customer has 15 days to execute the Initial Study Agreement and return to PJM.
4. PJM has 60 days to perform the Initial Study. The cost of the study is estimated at $5K, and usually billed after the study.
   - The Initial Study: ATC screening, Full Network Analysis, ASTFC screening, Load Deliverability, and Generator Deliverability.
5. If the Initial Study results indicate that a further impact study is needed, PJM sends out a System Impact Study Agreement (SISA).
6. Customer has 30 days to execute the System Impact Study Agreement and return to PJM, along with a $50K deposit.
   - PJM performs the System Impact Study based on the tariff deliverable dates. (Section 205.3 Timing of Studies)*

Queue	Customer submits Request		PJM System Impact Study	
	START	END	START	DELIVERABLE
1	May 1, Y1	Oct 31, Y1	Jun 1, Y2	Sep 29, Y2
2	Nov 1, Y1	Apr 30, Y2	Dec 1, Y2	Mar 31, Y3
** Effective 5/1/2012 – Docket #: ER12-1177-000*				

7. If the System Impact Study indicates that upgrades are needed, PJM sends out a Facilities Study Agreement (FSA).
8. Customer has 30 days to execute the Facilities Study Agreement and return to PJM, along with an estimated deposit of $15K for 2MW and under, $50K for between 2MW and 20MW, and $100K for 20MW and above. If the estimated amount of the Facilities Study cost for the first three months exceeds $100K, then that amount will be used as the estimated cost.
9. PJM performs the Facilities Study. This is typically done in, but not limited to 180 days.
   - The Facilities Study: Attachment Facilities, Local Upgrades, Network Upgrades, and "SCHEDULE OF WORK".
10. PJM sends out the Facility Study results and an Upgrade Construction Service Agreement (UCSA).
11. Customer has 60 days to execute the Upgrade Construction Service Agreement.

Manual 02: Transmission Service Request (http://www.pjm.com/~/media/documents/manuals/m02.ashx)
Manual 14A: Generation and Transmission Interconnection Process (http://www.pjm.com/~/media/documents/manuals/m14a.ashx)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

The Application Of Kentucky Power Company For (1) A	
Certificate Of Public Convenience And Necessity	)
Authorizing Kentucky Power To Convert The Existing	)
Big Sandy Unit 1 To Be Exclusively Fueled By Natural Gas	) Case No. 2013-
(2) For Declaratory Rulings; And (3) For All Other	
Required Approvals And Relief	)

DIRECT TESTIMONY OF

ROBERT L. WALTON

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Robert L. Walton being duly sworn, deposes and says he is the Managing Director of Projects for American Electric Power and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

ROBERT L. WALTON

STATE OF OHIO)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 3rd day of December 2013.

Regina L. Walker
Notary Public

My Commission Expires: 03-18-2017

REGINA L. WALKER
Notary Public, State of Ohio
My Commission Expires 03-18-2017

DIRECT TESTIMONY OF
JOSEPH KARRASCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00-___

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DIRECT TESTIMONY OF ROBERT L. WALTON, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WHAT IS YOUR NAME, BUSINESS ADDRESS AND POSITION?

A. My name is Robert L. Walton, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director of Projects. AEPSC supplies engineering, financing, accounting, project management and planning and advisory services to the ten electric operating companies of the American Electric Power ("AEP") System, one of which is Kentucky Power Company ("Kentucky Power" or "Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from The Ohio State University in Columbus, Ohio in 1974 with a Bachelor of Science Degree in Mechanical Engineering. From 1975 to 1978 I was employed by the Babcock and Wilcox Company ("B&W") as a Field Service Engineer. From 1978 to 1985, I was employed by the B&W Construction Company in various positions of increasing responsibility including Site Project Engineer, Site Construction Manager, and ultimately Regional representative, responsible for all aspects of Company business in a five-state area.

I joined American Electric Power ("AEP") in 1985 as a Senior Engineer progressing to Assistant Manager in 1987 and then to Manager of Maintenance Planning in 1988. In 1993, I was named Manager of Steam Generation Engineering and became Manager, Selective Catalytic Reduction ("SCR") Engineering in 1999. In 2000, I became the Director, Engineering & Consulting Services West. In 2003, I was named Director, Environmental Projects and subsequently named Managing Director, Plant and Environmental Retrofit Projects in April 2006. In November 2010 I was named to the position of Managing Director of Projects and Controls with expanded additional responsibility for project scheduling and monitoring services as well as cost analysis and control services, and most recently named Managing Director of Projects.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF PROJECTS FOR AEPSC?**

A. I am responsible for the safe and efficient planning and execution of AEP's Environmental and Other Production Capital construction program, consisting of multiple individual projects across AEP's East Fleet of generating facilities. Reporting to me and under my responsibility are the Project Directors and Project Managers, each responsible for individual and multiple projects.

Q. **HAVE YOU BEEN INVOLVED IN ANY OTHER PROJECTS WHERE A COAL-FIRED GENERATING UNIT HAS BEEN CONVERTED TO A NATURAL GAS-FIRED UNIT?**

A. Yes. During the time that I was Manager of Steam Generation Engineering, I had ultimate responsibility for the coal-to-gas conversions performed on multiple generating units owned by affiliates of Kentucky Power. These generating units were Conesville Plant Units 1, 2, and 3, and Picway Unit 5, all located in Ohio. I am also currently involved in a project to convert two units at Appalachian Power Company's Clinch River Plant from coal to natural gas firing.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I offered testimony on behalf of Kentucky Power before the Kentucky Public Service Commission ("Commission") in Case Nos. 2011-00401 and 2012-00578. I have also submitted written testimony on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission in Cause Nos. 43636, 43636 ECR 1, 44033, and 44331 as well as written testimony before the Michigan Public Service Commission in Case No. U-16801. In addition, I have submitted written testimony on behalf of Appalachian Power Company in Case Nos. PUE-2008-00045 and PUE-2013-00057 before the Virginia State Corporation Commission, and offered testimony on behalf of Appalachian Power Company in Case No. 13-0764-E-CN before the Public Service Commission of West Virginia.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support Kentucky Power's proposal to convert the coal-fired Big Sandy Unit 1 to exclusively burn natural gas (the "gas conversion" or the "Project"). Specifically, I will describe the unit's planned design modifications and anticipated performance after the gas conversion project is completed. I will also address the new natural gas pipeline lateral required for the Project and the planned contractual arrangements that will obtain a competitively-priced natural gas supply to fuel the converted Big Sandy Unit 1.

I will also describe the cost estimate, construction plan, schedule, and project management methodology that the Company will use for the Project.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring the following exhibits:

Exhibit RLW-1 – Project Schedule

Exhibit RLW-2 – Project Feasibility Study

Exhibit RLW-3 – Project Cost Estimate and Risk Analysis

Q. WERE YOUR EXHIBITS USED TO SUPPORT YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. PROPOSED MAJOR UNIT MODIFICATIONS

Q. WHICH UNIT AT THE BIG SANDY PLANT IS PROPOSED TO BE CONVERTED FROM BURNING COAL TO NATURAL GAS?

A. Kentucky Power proposes to convert Unit 1 at the Big Sandy Plant from a coal-fired to a natural gas-burning unit. As discussed in the testimonies of Company Witnesses Wohnhas and Weaver, Kentucky Power plans to retire coal-fired Unit 2 no later than June 1, 2015.

Q. IN YOUR PROFESSIONAL OPINION, IS BIG SANDY UNIT 1 SUITABLE FOR CONVERSION FROM COAL TO GAS FIRING?

A. Yes. Big Sandy Unit 1 is well suited for a coal to natural gas conversion. The majority of the infrastructure that is currently in place can be utilized, including such items as plant buildings and structures, steam turbines and electrical generator, electrical distribution systems, condensate and feedwater systems, along with wastewater processing equipment.

Q. PLEASE DESCRIBE THE MAJOR UNIT MODIFICATIONS REQUIRED TO BE MADE TO BIG SANDY UNIT 1 FOR THE GAS CONVERSION.

Major unit modifications required on Big Sandy Unit 1 include, but are not limited to, changes to the existing steam generator (boiler) and unit control systems to accommodate the combustion of natural gas, the installation of new fuel metering and regulating facilities for the natural gas, and modifications to the associated balance of plant systems. Specific work to be performed on the unit includes, but is not limited to:

- Modifications to the steam generator (boiler) pressure part circuitry;
- Replacement of the existing coal combustion burners with natural gas burners;
- Installation of new gas piping and valve racks;
- Installation of new gas burning igniters;
- Installation of new main flame scanners;
- Associated electrical, instrumentation and burner management control system modifications;
- Continuous Emissions Monitoring System modifications;
- Installation of new fuel gas check metering, heater and pressure regulating station; and
- Installation of (2) flame scanner cooling air blowers.

The gas conversion Project will also involve the installation of a natural gas transport supply lateral external to the Plant site, as discussed later in my testimony. Other than the natural gas supply lateral, the Project will be contained within the property boundary of the Big Sandy Plant.

Q. **WHAT WILL BE THE ROLE AND OPERATING CHARACTERISTICS OF UNIT 1 POST-CONVERSION?**

A. After the conversion of Big Sandy Unit 1 to natural gas firing the unit will continue to be dispatched based on economics, and it is anticipated that the unit will operate in a similar fashion as it does as a coal-fired unit, albeit with a slightly lower capacity factor. The converted unit will allow Kentucky Power to provide reliability benefits and potentially offset higher-priced market purchases during peak time periods, as discussed by Company Witness Weaver. The unit will also be able to offer certain generation-related ancillary services to transmission providers including synchronized reserves, day-ahead reserves, and voltage support.

Big Sandy Unit 1 is expected to experience a slight decrease in its output capability, from the current 278 MW net summer rating to an expected 268 MW net summer rating while burning natural gas. The average heat rate for the converted unit is expected to be slightly higher than the current heat rates at those same load points.

Company Witness Weaver further discusses the assumptions regarding plant performance and operating costs.

Q. **WHY IS THE COMPANY PROPOSING TO CONVERT BIG SANDY UNIT 1, BUT NOT BIG SANDY UNIT 2, INTO A NATURAL GAS-FIRED GENERATING UNIT?**

A. Unlike Big Sandy Unit 1, which is a subcritical operating unit by design, Big Sandy Unit 2 is a supercritical "once-through" unit design where operations at very low load are impractical. For example, the minimum obtainable stable output for a converted Big Sandy Unit 2 would be greater than the maximum output for a converted Big Sandy Unit 1 and thus, no comparable operating flexibility would exist. In addition, again based upon unit design characteristics, conversion of Unit 2 in lieu of Unit 1 would necessitate the installation of a new auxiliary boiler to facilitate unit startup. This would increase both the capital and operational costs of the fuel conversion.

Q. **WHAT IS THE DRIVING NEED FOR REFUELING BIG SANDY UNIT 1?**

A. Big Sandy Unit 1 will not be able to continue operation as a coal-fired unit beyond the MATS compliance deadline without addition of emissions control equipment or a change in fuel. It has been determined that a conversion of the unit to natural gas firing is a cost-effective approach to maintaining operation of this capacity to meet the needs of Kentucky power customers.

The MATS Rule requires units to be compliant with the emission limits by April 16, 2015. However, up to a one-year administrative extension can be granted by a state's Department of Environmental Protection for generating units that will undergo major retrofit or replacement projects to comply with the MATS Rule.

Q. **WHEN IS THE BIG SANDY UNIT 1 CONVERSION TO NATURAL GAS PLANNED TO BE COMPLETE?**

A. The conversion of Big Sandy Unit 1 is expected to be complete by mid-May 2016. Consequently, Kentucky Power will seek up to a one-year administrative extension to the MATS rule deadline for Big Sandy Unit 1 to continue operating as a coal-fired power unit until the conversion outage begins and no later than April 16, 2016, which will provide the additional time needed to complete the conversion to natural gas. The rate impact of the MATS Rule on the Big Sandy Unit 1 conversion is discussed in more detail in the testimony of Company Witness Wohnhas.

Q. **WHY IS IT NECESSARY FOR KENTUCKY POWER TO SEEK A ONE-YEAR EXTENSION UNDER THE RULE, RATHER THAN COMPLETE THE CONVERSION IN 2015?**

A. As shown in the Project Schedule in **Exhibit RLW-1**, the planned 2016 in-service date is the result of many factors. The Company has not finalized a contract for the gas pipeline lateral, nor has the company released the contracts for the Architect/Engineering or the steam generator OEM to proceed with the final detailed engineering and design and the procurement of the equipment associated with the unit modifications. Additionally, once Kentucky Power Company has awarded the contract for the pipeline lateral construction, that company will have its own schedule for engineering, design, procurement, permitting and construction that must be factored into the overall project schedule. These items, along with the lead times necessary for procuring and constructing the modified plant equipment and on-site gas pipeline lateral, make a 2015 in-service date impractical.

Aside from the above impacts to the Big Sandy Unit 1 Conversion Project, the impact of the resolution of Case No. 2012-00578 and transfer of an undivided 50% interest in the Mitchell generating station to Kentucky Power on the timing of the Project is discussed in the testimony of Company Witness Wohnhas.

IV. <u>NATURAL GAS PIPELINE</u>

Q. **HOW WILL NATURAL GAS BE PROCURED FOR BIG SANDY UNIT 1?**

A. Kentucky Power will purchase natural gas as a commodity from gas suppliers and producers. Due to the fluctuating natural gas requirements associated with the expected peaking operation of the converted facility, Kentucky Power requires flexibility in its natural gas supply and transportation arrangements. Natural gas volumes needed by Kentucky Power to match customer load demand require instantaneous, hourly, and daily flexibility in the delivery flow. To meet these needs, Kentucky Power plans to rely predominantly on daily spot market natural gas purchases as other AEP affiliates have historically done for operation of their peaking gas-fired generating plants.

Q. HOW WILL NATURAL GAS BE DELIVERED FOR USE AT THE BIG SANDY PLANT?

A. Currently, the Big Sandy Plant does not have provisions for natural gas delivery to the site. In conjunction with the Project, it will be necessary for a pipeline company to construct a natural gas pipeline lateral. We envision that this pipeline company will own the lateral and be responsible for all procurement, engineering, design, construction, installation, land rights, and permitting activities necessary to place this pipeline in service. The pipeline company will operate and maintain the facilities necessary to support the gas delivery, gas temperature, and gas pressure requirements of the Plant. No natural gas storage is planned at the Big Sandy site.

Q. PLEASE DESCRIBE THE PROCESS TO SOLICIT COST ESTIMATES FOR THE NATURAL GAS PIPELINE WORK.

A. AEPSC's Engineering Services, AEPSC's Project, Controls & Construction and AEPSC's Fuel, Emissions and Logistics ("FEL") organizations worked collaboratively with Kentucky Power to identify gas quality and delivery requirements for the Plant that will allow Unit 1 to burn natural gas to meet the capacity and energy needs for Kentucky Power's customers. FEL then contacted FERC-regulated interstate natural gas pipeline owners and confidentiality agreements were signed so that details of the potential Project could be exchanged and high-level desktop capital cost estimates could be provided. The natural gas transporters then submitted indicative capital cost estimates and FEL representatives conducted follow-up meetings to review the details of the information provided, including their ability to provide reliable gas transportation service and proactive pipeline maintenance, and to clarify any questions related to the indicative cost estimates and installation schedule.

Q. **WHAT WILL BE THE PRIMARY CRITERIA IN SELECTING THE GAS TRANSPORTER?**

A. Kentucky Power will select the least-cost transporter that best meets the specification requirements, best meets vendor risk and credit qualifications, and demonstrates the ability to provide long-term gas transportation service reliability.

Q. **AS A RESULT OF THE INITIAL GAS SUPPLY AND TRANSPORTATION PROCESS, WAS A GAS TRANSPORTER SELECTED TO ENGINEER, PROCURE AND CONSTRUCT THE GAS PIPELINE LATERAL FOR THE BIG SANDY PLANT?**

A. No. The final award of the gas transportation contract has yet to occur, but will proceed as soon as practicable, as described below in more detail, following receipt and evaluation of the Project proposals.

Q. **WHEN IS THE CONSTRUCTION OF THE NATURAL GAS PIPELINE LATERAL TO THE PLANT EXPECTED TO BEGIN?**

A. The gas transporter selected will conduct the planning for construction of the pipeline, including the required regulatory filings, right-of-way permitting, and other pertinent activities required prior to commencing the actual construction of the pipeline lateral. Kentucky Power will request the construction schedule and in-service date for the pipeline and associated facilities be aligned with the start-up and commissioning requirements in the Project schedule shown in **Exhibit RLW-1**.

Q. **WILL THE NATURAL GAS PIPELINE BE UTILIZED TO PROVIDE OR ENHANCE FUEL SUPPLIES TO OTHER ENTITIES?**

A. No. The Project's pipeline lateral will be dedicated solely to the Big Sandy Plant and will not be utilized to provide or enhance gas supplies to other entities.

Q. **WILL KENTUCKY POWER INSTALL ANY EQUIPMENT RELATED TO THE GAS PIPELINE LATERAL AND ASSOCIATED EQUIPMENT?**

A. Yes. Kentucky Power will install additional pipeline and equipment from the gas transporter's termination point, consisting of approximately 800 linear feet of gas piping to the boiler building. This will include a fuel gas check metering station, heater and pressure reducing station.

V. PROJECT EXECUTION

Q. **PLEASE PROVIDE AN OVERVIEW OF THE CURRENT EXECUTION PLAN FOR THE BIG SANDY UNIT 1 GAS CONVERSION PROJECT.**

A. The Project will be completed using elements of the same phased approach that has been successfully employed on many past projects on the AEP system. Feasibility and engineering and design studies, such as those included in **Exhibit RLW-2**, have been conducted to: (1) clearly identify the Project drivers; (2) provide a high level determination of the scope of work required; (3) produce an indicative cost estimate for the Project; (4) perform a high level risk and risk mitigation assessment; (5) produce an initial milestone schedule; and (6) provide inputs to the economic analyses performed by Company witness Weaver. Following the study, the Project will be executed in three phases – Phases I, II, and III.

The major activities conducted in Phase I include air emissions modeling, the completion of the conceptual design, preparation of a cost estimate, development of a Level 1 overall Project schedule, and the gas supply and transportation analysis for the new gas pipeline lateral. Upon completion of the Phase I activities, the Project Team will solicit the approval of Kentucky Power management to immediately proceed with Phase II work.

The major activities to be conducted during Phase II of the Project include preliminary engineering and design work, submission of key permit applications, award of original equipment manufacturer ("OEM") contracts, procurement of long lead time equipment and materials, and the evaluation of proposals and the ultimate award of the contract for the new gas pipeline lateral. Upon the completion and review of the Phase II activities, the Project Team will again solicit the approval of Kentucky Power management to proceed with Phase III.

In Phase III, the primary activities will be the finalization of all prior activities, the release of all remaining procurements and the completion of the construction, start-up and commissioning of the gas conversion work and the natural gas pipeline lateral.

A detailed evaluation, followed by financial authorization, is required before the Project can proceed from one phase to the next. A graphic timeline incorporating the phased approach, as well as major Project milestones, including this certificate process, is provided in Exhibit RLW-1.

Q. IN WHAT PHASE IS THE BIG SANDY UNIT 1 GAS CONVERSION PROJECT CURRENTLY?

A. The Project Team is currently concluding Phase I activities. The initial Project planning, conceptual engineering and initial cost estimate work required to support this filing have been completed.

Q. PLEASE DESCRIBE THE ACTIVITIES THAT HAVE BEEN COMPLETED AND ARE IN PROGRESS DURING PHASE I.

A. The formal process began with the preparation and approval of the Project Charter, including multiple stakeholder meetings to review the concepts of the Project. The Project Charter, a document typically generated by the Project Manager, was utilized to formally request and obtain authorization of initial Project funding, define a high level scope of work for the Project, define the goals and objectives and success criteria for the Project, and present a preliminary high level cost estimate and initial Project schedule. Following approval of the Project Charter, AEPSC and B&W ("Boiler OEM") engaged and performed the initial engineering, design, and technical evaluation to support Phase I activities. The intent of the Phase I technical evaluation was to determine feasible options and factors driving the Project cost and schedule. During Phase I, AEPSC also utilized Worley Parsons, an independent Architect/Engineering firm, to further define the scope of the Project, provide key environmental modeling inputs, complete conceptual engineering, further develop the Project schedule, and develop a cost estimate. AEPSC's Environmental Services organization will utilize the inputs from the OEM and AEPSC's engineering resources to complete any required air modeling and prepare environmental permit applications. In addition, FEL solicited preliminary information from local gas transporters that established scope, provided natural gas pipeline lateral high level indicative capital cost estimates, and outlined estimated construction timelines for the natural gas pipeline lateral. The results of the Phase I conceptual engineering and technical evaluations are being prepared for presentation to Kentucky Power management in order to gain their approval to proceed with Phase II.

Q. WILL THE PHASE I TECHNICAL EVALUATIONS COVER THE ENTIRE SCOPE OF THE BIG SANDY UNIT 1 CONVERSION PROJECT?

A. Yes. AEPSC has defined the responsibilities of the assigned parties not only for the fuel conversion technology, but also site development, natural gas pipeline oversight, and the identification of all permitting requirements.

Q. PLEASE DESCRIBE THE ACTIVITIES THAT WILL TAKE PLACE IN PHASE II.

A. Phase II work consists of completing the preliminary engineering and design and the permitting work and commencing procurement activities. During this phase, we will finalize the Project scope, further refine and update the cost estimate and Project schedule, award the OEM contract, procure long lead time equipment and materials, and perform the detailed engineering. During Phase II, applications to modify existing environmental permits will be submitted to the Kentucky Department of Environmental Protection ("DEP") so that they may begin their evaluation and approval process. The Company will also evaluate proposals and award the contract for construction, operation and maintenance of the natural gas pipeline lateral.

Late in Phase II, bid packages will be prepared and requests for proposals ("RFPs") issued for the construction portion of the Unit 1 conversion work. The construction and site management teams will be established to begin making necessary preparations for site construction work and to participate in the process of selecting and awarding the major construction contracts.

Q. **WHAT ACTIVITIES WILL OCCUR DURING PHASE III?**

A. Phase III consists of the major construction, followed by startup and commissioning of the overall Project. The start of Phase III is predicated upon the receipt of the air permit authorizing construction from the Kentucky DEP. Although not anticipated, a major delay in the receipt of the air permit could result in schedule and cost impacts to the overall execution of the Project. During Phase III, the principal construction contractors will mobilize and begin the major construction effort. In addition, all gas pipeline construction will be completed to support the tie-in to the on-site gas metering and pressure reducing equipment and to support the necessary testing. Phase III is complete when the overall Project is commissioned and placed in service and Project closeout activities have concluded.

Q. **WHAT ARE THE MAJOR BENEFITS DERIVED FROM THIS PHASED APPROACH?**

A. The phased approach to project management is used commonly by AEPSC and is considered a best practice in managing large projects. The utilization of "phase gates" at the end of each phase provides a logical break point for the project team to evaluate its progress against the stated goals and objectives for the project. It also establishes defined points for the AEPSC project team to report progress to Kentucky Power management with respect to the project success criteria and any critical risks or opportunities that may have been identified.

Q. PLEASE GENERALLY DESCRIBE THE PROCESS TO BE USED TO SELECT A CONSTRUCTION CONTRACTOR FOR THE BIG SANDY UNIT 1 GAS CONVERSION PROJECT.

A. AEPSC has processes for evaluating and qualifying construction contractors to ensure they have the capability to perform work of the type and scope envisioned and a demonstrated record of safety focus and performance. Proposals are requested from two or more of these contractors. The final award is based on the total evaluated costs and safety performance of those bidders, along with ancillary considerations such as a financial risk and credit assessment, negotiated shared risk/reward programs, and similar factors.

VI. BIG SANDY UNIT 1 PROJECT COST ESTIMATE

Q. WHAT IS THE ESTIMATED COST FOR THE CONVERSION OF BIG SANDY UNIT 1?

A. The total estimated capital cost of the Project, excluding allowance for funds used during construction ("AFUDC") and the gas transport lateral cost, is $50 million. This cost estimate was provided to Company Witness Weaver for use in the economic analysis of the Big Sandy Unit 1 disposition options. The cost estimate detail can be found in **Exhibit** RLW-3.

Q. HOW WAS THE COST ESTIMATE FOR THE PROJECT DEVELOPED?

A. The cost estimate was developed by utilizing inputs from multiple industry consultants and natural gas transporters, with oversight from AEPSC. The boiler modification material and labor cost estimates were obtained from the boiler OEM and AEPSC Engineering Services. In addition, AEPSC utilized the services of the independent architecture and engineering firm to provide cost estimates for the balance of plant work on the Project not covered in the boiler OEM scope of supply and to integrate the entire cost estimate for the engineering, procurement, construction, startup and commissioning of the Big Sandy natural gas conversion project.

After obtaining the inputs from all of these entities, the Project team from AEPSC consolidated all of the estimates and included Owner's costs and overhead allocations to arrive at the total Project cost estimate.

Q. **WHAT OTHER ACTIVITIES MUST BE COMPLETED PRIOR TO THE DEVELOPMENT OF A MORE DETAILED COST ESTIMATE?**

A. As outlined above, the Project has essentially concluded Phase I preliminary engineering and design. During Phase II, the cost estimate will be further refined. Phase II activities will include commencing detailed engineering and design, and entering into the contracts for long lead equipment. All of these activities are essential to further defining the detailed scope and cost of the Project.

Q. **IS IT YOUR PROFESSIONAL OPINION THAT KENTUCKY POWER HAS DEVELOPED A REASONABLE COST ESTIMATE FOR CONSTRUCTION OF THE PROJECT?**

A. Yes. The cost estimate for the Project is reasonable considering the development basis and the amount of site-specific engineering and design work completed to date. The current refined $50M estimate reflects sufficient risk dollars to ensure that the final job cost should not exceed the estimate. AEPSC has successfully used this cost estimation procedure for numerous other construction projects throughout the AEP system.

Q. PLEASE DESCRIBE OTHER MAJOR PROJECTS THAT HAVE BEEN SUCCESSFULLY MANAGED AT AEP UNITS.

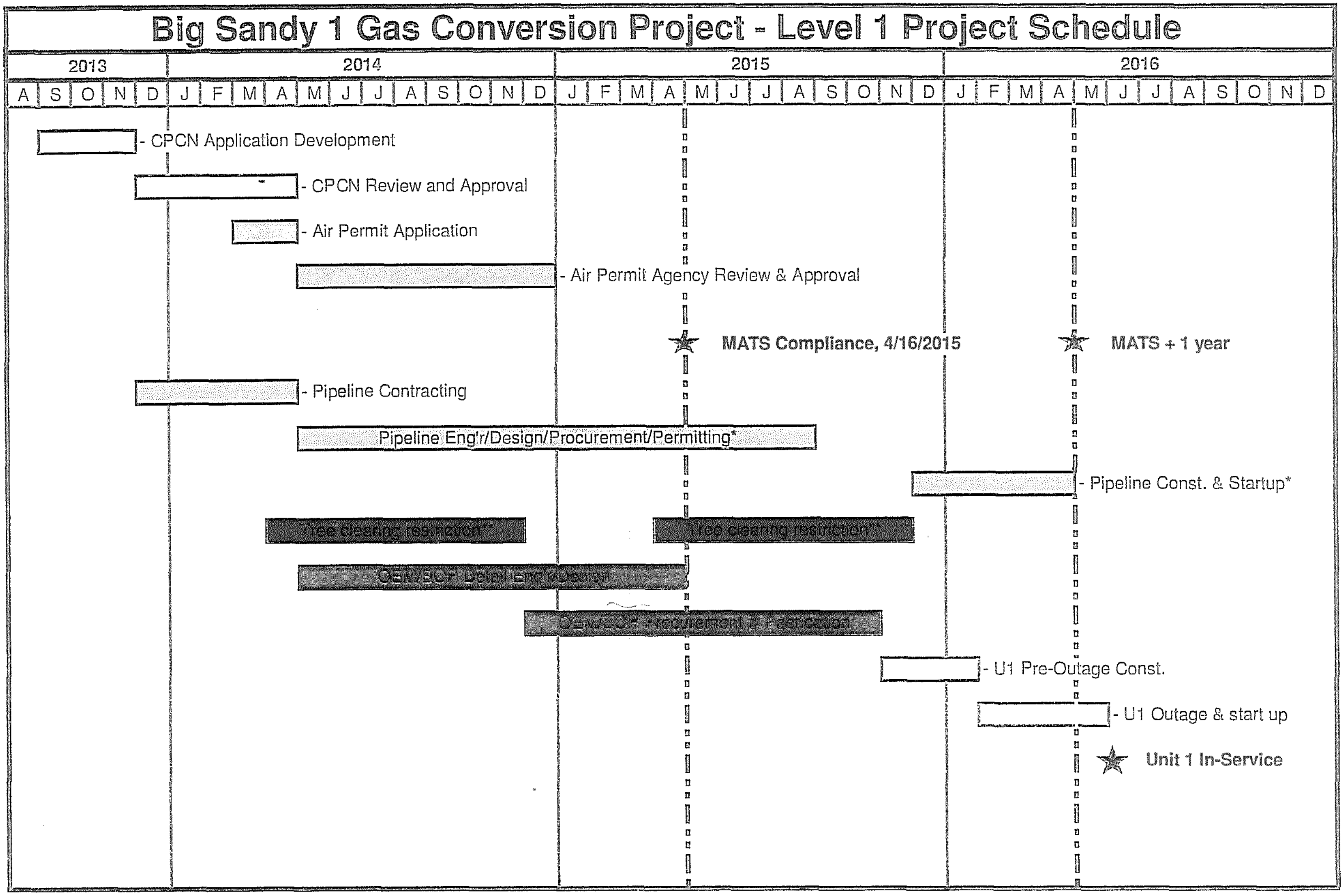
A. AEPSC has a long history of successfully managing major construction projects and major unit outage work, including environmental retrofit projects and numerous boiler component replacements and modifications. Similar retrofit projects have, in fact, been managed on Big Sandy Unit 1, including burner and pressure part replacement projects.

In addition, AEPSC has recent experience completing both combined cycle and simple cycle gas turbine projects that include similar gas delivery activities to what will be included in the Big Sandy Unit 1 Project.

Throughout all of these projects, AEPSC has built a strong project management, construction management, project engineering, project controls, and start-up and commissioning organization. The knowledge and experience of this team of individuals combined with our industry partners and project management processes have and continue to produce our track record of successful projects.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes.



* - This portion of the project to be the responsibility of the gas pipeline company

** - The tree clearing restriction is applicable to the pipeline company only

B&W Engineering Study P027478

to

American Electric Power Company

for

Natural Gas Conversion

at

Big Sandy Unit 1

submitted by

power generation group

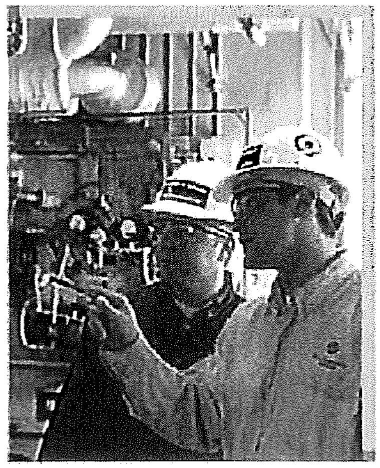
November 19, 2013

APPENDICES

INTRODUCTION

The Babcock & Wilcox Power Generation Group (B&W) has provided decades of unparalleled professional expertise and service to a host of utility and industrial customers and continues to be a leader in the supply of boiler equipment for the power generation industry. Founded in 1867, B&W is the oldest continuously operating boiler company in the United States. With over 145 years of history, B&W is well known for its innovations and product excellence in the areas of steam generation, fossil fuel combustion, and environmental controls.

B&W Service Company (BWSC)



B&W Service Company, a division of The Babcock & Wilcox Power Generation Group, has over 500 permanent employees and can draw on corporate manufacturing and specialized engineering resources as well as contract field service and labor to support its work activities. The BWSC business units, Service Projects, Replacement Parts, Field Engineering Services, Package Boilers, and Private Power Systems are supported by Engineering, Sales, and a host of administrative organizations. The group with responsibility for the work proposed herein, Service Projects, carries out unit maintenance and upgrade projects ranging from total EPC SCR installations to in-kind replacements of boiler components. We draw on support from an engineering and design group having an average of almost two decades of experience per employee and from estimating, scheduling, accounting, quality assurance, manufacturing, and construction organizations.

On large and complex projects typical in the power generation industry today, success is based in large part on the supplier's ability to coordinate all the different disciplines required to complete the project. We are in a unique position in the industry to undertake these projects because personnel with all of the requisite skills are co-located on our Barberton, OH, campus, thus facilitating the exchange of information throughout planning, project execution, and start-up activities.

Research and Development

B&W established a Research and Development Division in Alliance, Ohio, in 1947 to maintain its leadership in custom-engineered systems and equipment for the power generation industry. In 2007 B&W celebrated the inauguration of its new 55,000-square foot research center co-located in Barberton, OH with its other business units supporting the power generation industry.

This research center focuses on the development efforts in the areas of steam production and pollution control technologies, as well as technologies to capture carbon dioxide (CO2) from the emissions of coal-fired power plants. The research center is the residence for B&W's new small boiler simulator (SBSII), an integrated combustion and environmental control test system; the fireside corrosion facility, which is used to evaluate advanced materials for super- and ultra-supercritical boilers; the mercury lab where bench-scale studies for flue gas desulfurization systems and mercury oxidation are conducted, and the entrained flow reactor, used to study the fundamental science of coal combustion.

Today, research specialists focus their attention on development in key technology areas including:

- combustion processes,
- emissions control,
- fuel cells,
- fuels characterization,
- numerical modeling,
- thermal hydraulics, and
- structural mechanics

Current examples of development efforts that utilize these technologies include fuel-cell power generation systems and advanced low-emission burners. Such developments are conducted in accordance with ISO 9001 certified procedures and frequently utilize the Combustion and Environmental Development Facility (CEDF). This integrated state-of-the-art combustion and emissions testing facility offers unique research, development, and demonstration capabilities to improve the environmental performance of current and future power plants.

Manufacturing

B&W maintains a commitments to heavy metal manufacturing at our facilities in Barberton, Ohio; West Point, Mississippi; Cambridge, Ontario, Canada; Melville, Saskatchewan, Canada; and our latest facility in Monterrey, Mexico. We also have access to facilities in Mt. Vernon, Indiana, and Morgan City, Louisiana, and joint venture operations in China and India. Our extensive facilities, skilled manpower, and global presence provide our customers with a complete range of fabricating processes around the world and around the clock. Advanced manufacturing methods and in-plant emphasis on quality ensure that retrofit components are made correctly and shipped on time. As a result, field fit-up problems are minimized and outage sc hedules can be maintained.

B&W wishes to thank American Electric Power for the opportunity to submit this study. Points of contact for questions and/or additional information are as follows:

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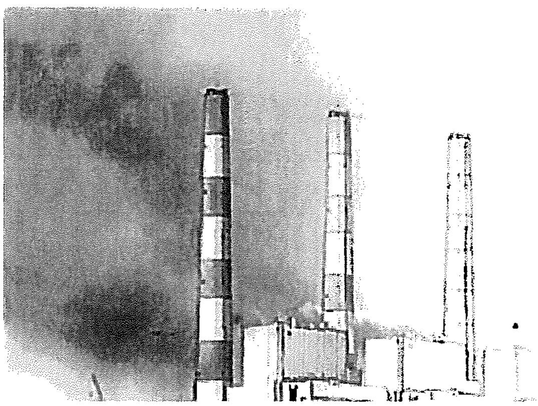
COMPANY EXPERIENCE AND QUALIFICATIONS

Babcock & Wilcox Power Generation Group, Inc. (B&W) has provided unparalleled professional expertise and service to a host of utility customers and continues to be a leader in the supply of boiler equipment for the power industry. Founded in 1867, B&W is the oldest continuously operating boiler company in the United States. With over 145 years of history, the company is well known for its innovations and product excellence delivering unparalleled results for the power industry.



- Babcock & Wilcox boilers supply more than 300,000 megawatts of installed capacity in over 90 countries around the world.
- Approximately half of the world's electric power is supplied by water-tube boilers. In addition, boilers using Babcock & Wilcox technology are now providing more than 23 percent of the world's boiler-powered electricity generation capacity, and more than 35 percent of the capacity in the U.S.

B&W's role as an original equipment manufacturer, B&W has an extensive resume as a major supplier of repair, refurbishment, and upgrade equipment.

Throughout our many years of successful performance, we have demonstrated technical competence, flexibility, and attention to "lessons learned."

Worldwide Manufacturing

Through comprehensive supply chain management, worldwide sourcing, and alliances with domestic and international fabricators, you can depend on quality materials, on-time delivery and reduced total cost. B&W PGG's commitment to quality products and services is also demonstrated by our continuous capital investments at our manufacturing facilities around the world.

Burner Equipment Upgrades

Our leadership in the field of NOx reduction technology began in 1962 with the award of the first patent for the use of overfire air for reducing NOx emissions in the world. That leadership continues with unparalleled experience, proven equipment, and innovative technology to this day. Our systems are designed to be cost-effective, dependable, and adaptable to the full range of fuels and boiler arrangements in new or retrofit applications.

Babcock & Wilcox's history of combustion design innovation, experience, and technology is unmatched in the industry, and the following study is supported by our long history of low NOx combustion innovation and success.

Since 1971, B&W has successfully installed over 135,000 MWe of low NOx combustion systems in both new and retrofit applications, including thousands of low NOx burners.

Operating & Maintenance

Mechanical reliability has been a primary design consideration for B&W burner equipment for over 50 years. Minimal maintenance requirements on B&W equipment have historically reflected the emphasis that we place on a rugged design to maintain operability. Our burner equipment is low maintenance and easy to operate. This traditional philosophy within B&W has not changed, and our new equipment designs continue to operate with high reliability and low maintenance requirements.

Company Financials

Please see visit our company website **www.babcock.com** for the latest financial information.

TECHNICAL DESCRIPTION

Overview

Engineering Study for the Natural Gas Conversion on Big Sandy Unit 1.

Unit Background

B&W contract RB-364 is a pressurized, radiant boiler that commenced operation in 1962. The original design fired pulverized coal from eighteen (18) burners located on the front and rear walls. The furnace dimensions are 42 feet wide, 28 feet deep and 120 feet from the lower wall header centerline to the drum centerline. The unit has a parallel path horizontal convection pass.

The original design maximum continuous rating (MCR) for Big Sandy 1 is 1,890,000 lb/hr of main steam at 1050°F and 2500 psig. The original reheat conditions at MCR are 1,534,000 lb/hr at 1050°F and 510 psig.

Superheater and reheater steam temperature control was originally by means of biasing dampers for the parallel path horizontal convection pass, gas recirculation, and spray attemperators.

The gas recirculation equipment has been removed and therefore neither gas recirculation nor gas tempering are in use. In addition, the biasing dampers in the horizontal convection pass are currently not functional. Therefore, the primary means of steam temperature control currently are spray attemperation and excess air.

The reheater materials were upgraded to T91 by others in the mid-1990s.

In 2008, B&W upgraded the secondary superheater outlet bank to TP304H material.

The secondary superheater inlet bank was also upgraded in 2008 to T22 (by others).

Both the reheater and secondary superheater outlet headers have been upgraded by others to P91 material.

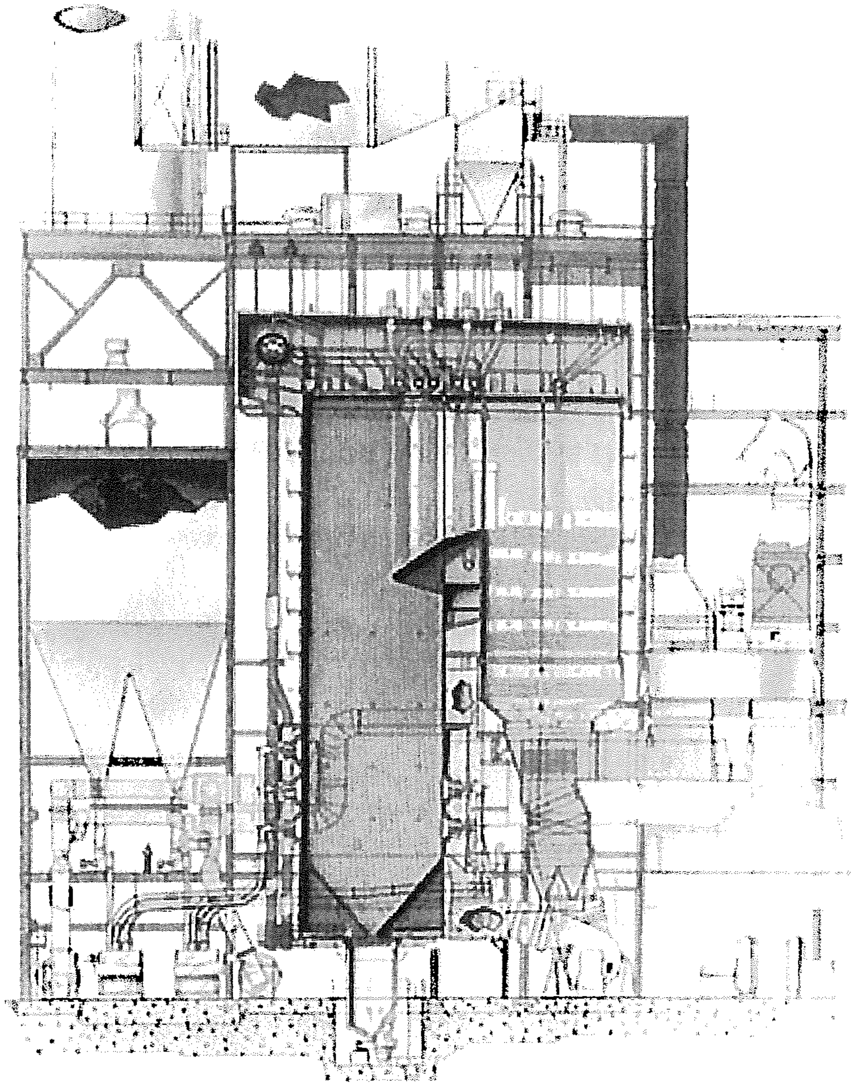


Figure 1 - AEP Big Sandy Unit 1 - (RB-364)

Design Basis

AEP provided several weeks of natural gas analyses for our review and use. The natural gas analysis used in B&W's performance predictions is listed below in Table 1.

Table 1: Fuel Analysis

Fuel Type	Natural Gas
	% by volume
Methane	76.69
Ethane	16.54
Carbon Dioxide	0.08
Nitrogen	1.13
Propane	4.33
Butane	0.94
Pentane	0.20
Hexane	0.09
Total	100.00
HHV(btu/ft)	1205

The boiler was designed for an MCR main steam flow of 1,890,000 lb/hr. For this Engineering Study, AEP advised that the top load should be 2,080,000 lb/hr main steam flow, where the unit has run since a turbine upgrade in 2008. In addition, we have reviewed the original control load and a "mini" load specified by AEP.

Expected Emissions Performance

Thermal NOx is controlled through the reduction in peak flame temperatures. This is accomplished through staging and a slow fuel/secondary air mixing rate. Due to the reducing environment, high levels of CO are produced which must be combusted when the balance of combustion air is reintroduced higher in the furnace (through OFA ports). The balance of combustion air has to be introduced in such a way as to avoid the formation of thermal NOx. To the extent that the OFA system is effective, low stoichiometries (and thus low NOx) are achievable while still oxidizing CO to acceptable levels.

In the effort to oxidize as much CO as possible, experience in system retrofits indicates that is advantageous to locate outermost OFA ports outboard of the outer burner columns between the burners and the sidewalls. Commonly, these ports are located halfway between the outer burner columns and the sidewalls to provide combustion air to oxidize the CO that typical forms along the sidewalls and in the corners of the furnace due to the colder environment in those areas.

The existing OFA ports do not offer the ability to balance straight jetted air versus spun air which would allow for increased mixing of the over-fire air with the substoichiometric combustion gases from lower in the furnace which in turn reduces CO formation.

The following options were considered in this Engineering Study:

Option 1 - New XCL - S burners with Existing OFA Ports

This option requires the least amount of modification and the lower expected NOx emissions of the two options. The NOx emissions for this modification option are not expected to exceed 0.22 lb/10^{6}btu from maximum load (2,080,000 lb/hr) to control load (1,260,000 lb/hr). Since the existing OFA ports will be reused in this option, the CO emissions are expected to be 115 PPM at 3% O_2. Due to the composition of the gas not being that of pipeline quality natural gas, B&W would like to refer to EPA's AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, Section 4: Natural Gas Combustion (Table 1.4-2) for expected VOC emissions.

Option 2 - New XCL - S burners with removed OFA Ports

This option requires the removal of the existing OFA Ports. The NOx emissions for this modification option are not expected to exceed 0.30 lb/10^{6}btu from MCR to control load. The CO emissions are expected to be 115 PPM at 3% O_2. Due to the composition of the gas not being that of pipeline quality natural gas B&W would like to refer to EPA's AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, Section 4: Natural Gas Combustion (Table 1.4-2) for expected VOC emissions.

Non-Pressure Parts

B&W XCL-S Burners

NOx Formation

NOx is formed during combustion of fossil fuels by several mechanisms. At flame temperatures in excess of 2800°F, significant quantities of thermal NOx are formed by dissociation and oxidation of nitrogen from the combustion air. Thermal NOx is the primary cause of NOx from firing natural gas, and a major contributor with fuel oil. Fuel NOx refers to emissions which result from oxidation of nitrogen which is bonded to the fuel molecules. This nitrogen becomes actively involved in the combustion process as hydrocarbon chains are broken and oxidized, and a portion of the fuel nitrogen is oxidized as a result. Fuel bound nitrogen is found to varying degrees in heavier fuel oils (and coal), but is insignificant in light oil (No. 2) and natural gas. Fuel NOx is the primary cause of NOx from pulverized coal and a major contributor for No. 6 fuel oil. Prompt NOx refers to emissions formed during combustion from hydrocarbon radicals dissociating atmospheric nitrogen, followed by oxidation. Prompt NOx plays a minor role in overall NOx production with fossil fuels.

NOx Control Strategies

Several methods are available to limit NOx formation during combustion effectively. The combustion system design will depend upon the capacity and fuels to be fired, as well as the requirements to limit NOx emissions. Thermal NOx can be controlled by reducing the thermal loading to the combustion zone. Mechanisms include increasing the size of the combustion zone for a given thermal input; reducing the rate of combustion and peak flame temperatures by burner design; and addition of re-circulated flue gas to the combustion air to depress flame temperature. Fuel NOx can be controlled by limiting oxygen availability during early phases of combustion. Mechanisms include reducing excess air; reducing burner stoichiometry by removing a portion of the combustion air from the burner and introducing this air later through NOx ports (air staging); and by burner designs which limit the rate of which air is introduced to the fuel early in the flame. Peak NOx levels tend to occur early in the combustion process as flame temperatures peak and while oxygen availability is highest, whether or not countermeasures are employed. The NOx formed early in the process can be reduced downstream by use of fuel staging principles. Fuel staging involves introduction of fuel downstream of the flame under fuel rich conditions. Hydrocarbon radicals can thereby be generated which attach the NOx molecules, resulting in NOx destruction.

Fuel staging can be accomplished by fuel staging burners located downstream of the main burners and in combination with air staging ports; or by a burner design to accomplish these effects by fuel injection/air flow patterns.

B&W XCL-S Burner

The B&W XCL-S burner makes use of air staging and fuel staging technology by virtue of its design. The gas elements are centrally located in the burner in an arrangement which carefully limits air/fuel interaction in the root of the flame. The fuel elements are all housed in a single, central flame stabilizer which results in excellent flame stability and turndown, while separating the fuel elements from the combustion air. The XCL uses multiple Hemi gas spuds to achieve the desired fuel injection patterns. Secondary air introduction to the fuel is regulated by dual air zones with multi-stage swirl vanes. Peak NOx formation is reduced by controlling the rate of combustion and apparent stoichiometry. Hydrocarbon radicals are produced which react with the NOx formed early in the flame and further reduce NOx emissions. Combustion air gradually mixes with these products of combustion further downstream to complete char reactions while minimizing NOx re-formation.

Burner Air Flow Control - Sliding Air Damper

The XCL-S burner can be used in either compartmented or open windboxes. Each burner is equipped with a sliding disk damper to regulate secondary air flow to the outer air zones for light off, normal operation, and burner out of service (BOOS) cooling.

A second sliding sleeve damper is provided for air biasing between the core air and the outer secondary air. The air biasing damper is set manually at commissioning and does not require adjustment during normal operation.

Burner Air Flow Control -BECK Electric Actuator

Each burner can be equipped with a BECK linear actuator specifically designed for application to XCL-S burners.

Burner Air Flow Control - Air Measuring Pitot Grid

The XCL-S is equipped with an air measuring device located in the air sleeve of each burner. This measuring device is an impact-suction or reverse type Pitot tube arrangement consisting of two separate manifolds joining six radial impact-suction tubes. This multi-point averaging grid provides a relative indication of air flow to each burner by measuring a pressure differential across the impact and suction manifolds. This air monitor is instrumental in detecting burner to burner flow imbalances within the common windbox and may be used as a tool for future tuning efforts.

Flame Control - Adjustable Gas Spud Orientation

Each of the gas spuds in the XCL-S burner is capable of having their rotational orientation adjusted on-line for greater operational and tuning flexibility. Such adjustments can be made from the burner front while the burner is firing.

Gas spud inspection/maintenance may occur with the unit in service and the burner out of service.

The cut-away view below is typical of the XCL-S burner arrangement when configured for gas firing.

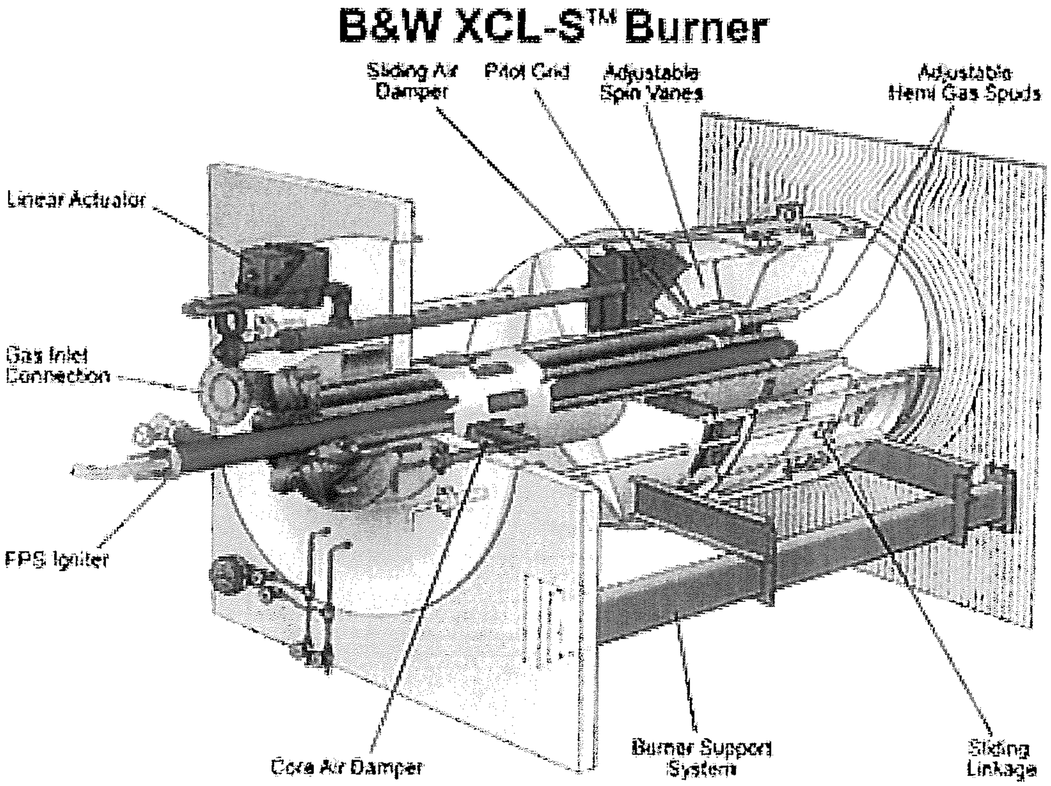


Figure 2 - B&W XCL-S Gas Burner

The scope of supply would include **eighteen (18)** XCL-S low NOx gas burners. All 18 burners will be located at an existing burner pressure part throat opening. No modification of the boiler tube wall would be necessary.

Fossil Power Systems (FPS) 4.0"OD HO Gas Ignitor, 4-20 Million BTU/hr

A Class I Ignitor assembly would be included to fit the a B&W XCL-S burner. Each ignitor is supplied complete with its own SunSpot flame detection system.

The 4.0"OD ignitor includes the integral Sunspot flame detection system. The SunSpot is an instrument designed to verify the presence of flame in FPS ignitors. It does this by measuring the ionization of gases caused by the combustion process. A probe is inserted into the flame envelope, and the ionization is detected by passing a small electrical current through the flame to ground. The SunSpot is reliable, requires no maintenance, and is very economical. It is supplied as an assembly, which includes the plug-in electronics module and a relay socket. Replacing the module takes only a matter of seconds.

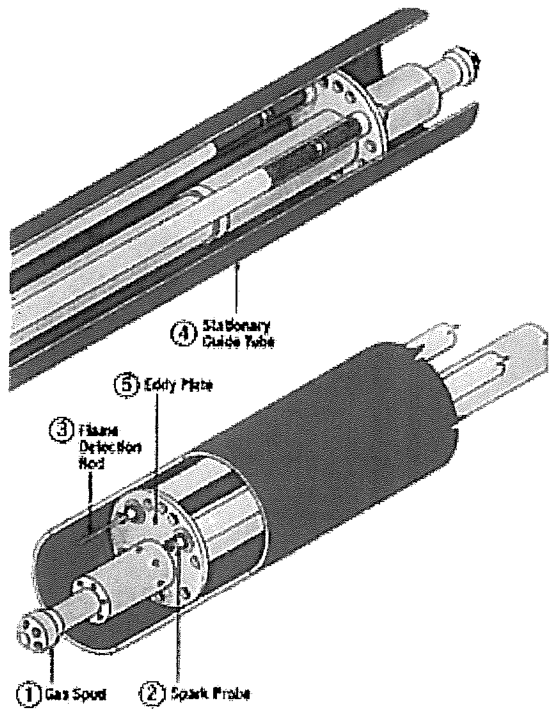


Figure 3 - FPS Gas Ignitor

Combustion Air Blower Skid & Air Piping

Each ignitor and scanner requires combustion air flow.

A duplex blower skid would provide adequate air flow to each ignitor. Pressure switches would be included as part of the blower supply to provide indication and control of header air pressure and can be wired directly to MCC equipment or the unit's DCS to provide backup fan starting. Each fan would include a filter/silencer.

Combustion air piping from the blower skid to the burner fronts would be required.

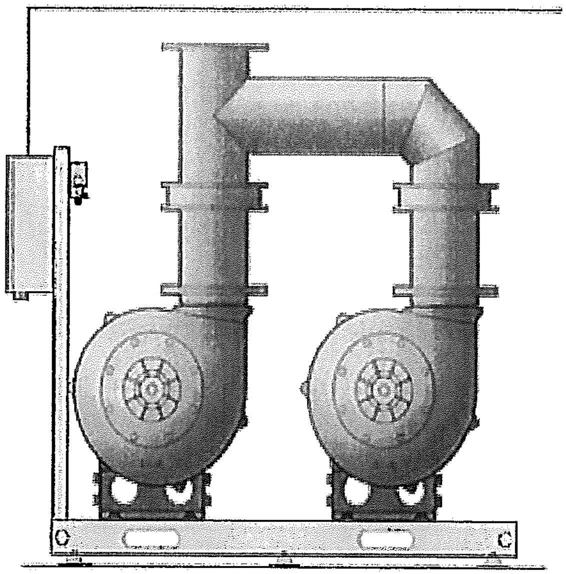


Figure 4 - FPS Duplex Blower

Main Flame Scanners

FPS, tri-color, rigid fiber optic, main flame scanners, and main flame scanner electronics cabinet.

FPS Scanner System Description

The scanner heads have the ability to detect the light emissions from the flame envelope in the infrared, visible and ultra-violet wave spectrum. This would allow the user unsurpassed flexibility in tuning the flame scanners for detection of gas flames.

The fiber-optic viewing head extends into the windbox and ends just before the exit into the furnace. The viewing lens is arranged in a skewed manner allowing an angled view into the furnace that can be easily adjusted on the boiler front. The primary benefit of the skewed viewing angle is that it allows the scanner to be sighted on the optimal area of the flame envelope for flame detection, while directing the scanner view away from the opposing burners and ignitors. A second benefit to this type of scanner arrangement is the ability to rotate the scanner head about its own axis, allowing the scanner to be sighted at the optimal area in the furnace for both flame detection and flame discrimination.

Main Gas & Ignitor Supply Header Station – see appendix B for P&ID's

A main gas header station would be necessary to control the flow feeding the Burner Front Valve Racks. This station contains instrumentation, block valves, vent valve, and flow control valves all preassembled on one assembly.

Valve Racks and Controls - Burner & Igniter On/Off Control – see appendix B for P&ID's

A valve rack per burner containing both the igniter and main gas double-block-and-bleed valve trains for on/off/vent gas flow control would be required.
These racks serve to provide on/off control to each burner and igniter and have no pressure reducing function.

The valve racks would be completely shop assembled. The control/terminal box would have indicating lights and operator controls with remote/local switch to provide for manual local operation and operation by a Burner management System.

Gas & Vent Piping – see appendix B for P&ID's

Natural gas piping from the natural gas header flow station to the local burner and ignitor valve racks would be required. Vent piping from the burner & ignitor supply header station discharging above the roof would also be required.

Pressure Parts

Existing Arrangement

Performance Boiler predicted performance was calculated using the current boiler arrangement with the indicated natural gas fuel for a range of boiler loads. Performance was analyzed in a natural gas "clean" and "dirty" condition.

The top load that AEP requested we review has a main steam flow of 2,080,000 lb/hr due to a turbine upgrade in 2008. It is important for AEP to recognize that the MCR rating for this boiler is 1,890,000 lb/hr and B&W has not reviewed safety valve capacity and/or settings nor unit circulation for the higher load.

B&W also reviewed the original control load of 1,260,000 lb/hr main steam flow and a "mini-load" requested by AEP of 780,000 lb/hr main steam flow (roughly 100 MW).

The unit was originally supplied with flue gas recirculation (FGR) and gas tempering capability. These features were eliminated when the plant removed the flue gas recirculation equipment years ago. Gas tempering was used to reduce the furnace exit gas temperature (FEGT) at higher loads and FGR was available at lower loads to assist in obtaining the desired superheater and reheater steam temperatures. Without the gas tempering and combined with the switch to natural gas, the predicted FEGT on natural gas is roughly 300°F higher than the original FEGT for coal firing while using tempering. The higher FEGT cascades through the boiler resulting in higher gas temperatures through the convection pass and this drives up tube metallurgy requirements.

The gas biasing dampers in the parallel path horizontal convection pass are no longer functional. Restoring their functionality would help to increase the reheat temperature at the lower loads by allowing additional flue gas to be directed to the reheat surface.

At the full load, both the superheater and reheater are predicted to make the desired 1050°F. At the lower loads, the reheater is predicted to not make full temperature. Not having the ability to turn on flue gas recirculation at the lower loads, and no gas biasing, contribute to this issue.

Natural gas firing (as compared to PC firing) results in a higher furnace exit gas temperature and higher attemperation spray flows. As superheater attemperator spray flow increases to control the secondary superheater (SSH) outlet temperature, to primary superheater (PSH) steam flow decreases accordingly and a PSH overheat conditions results.

Superheater and Reheater Superheater and reheater metallurgy was evaluated for natural gas firing based on the existing surface arrangement. B&W uses the ASME Code to determine tube metallurgies and thicknesses. The design temperatures however are based on B&W procedures. Design temperatures are determined through the consideration of gas and steam side temperature and flow upsets and unbalances. The upsets and unbalances include FEGT empirical uncertainty, top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to each row of the superheater and reheater. Tube row metallurgy and thickness are then determined from the resultant tube OD and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses

Many of the Big Sandy 1 tubes have been calculated to operate in a temperature regime where creep occurs. In this regime there is a relationship between allowable stress and life expectancy. Per the 1995 ASME Code Section II, Part D, Appendix 1, Paragraph1-100 (page 696), the allowable stresses are set based on the most conservative of the following three criteria: 100% of the average stress to produce a creep rate of 0.01% per 1000 hours, 67% of the average stress to cause ruptures at 100,000 hours or 80% of the minimum stress to cause ruptures at 100,000 hours.

Further, the remaining tube life expectancy is dependent on the prior operating history, especially on actual tube operating temperatures as compared to design temperatures. The constituents of the flue gas affect heat transfer to the tube banks and consequently affect the tube operating temperature. A fuel switch from coal to natural gas significantly changes the flue gas analysis. Thus, assessing the existing superheater and reheater materials for the proposed natural gas conversion is not straightforward.

Operating hoop stresses (based on the originally supplied minimum tube wall thickness) were determined. The predicted tube operating temperatures, based on B&W's standard design criteria, and the resulting ASME Code allowable stress levels for the existing materials were also determined. Comparing the hoop stress to the code allowable stresses, a percent overstress determination can be made. A modest overstress indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant immediate tube replacement.

If the overstress analysis shows significant overstress or shows tubes are operating at temperatures above published ASME Code limits, then tube replacement should be considered. Significant overstresses are those tube rows with 20% or greater overstress. An overstress of 20% or more does not necessarily mean that immediate replacement is required, but it identifies which tube rows should be monitored regularly. Signs of creep, internal exfoliation, or swelling should be included in the condition assessment process.

B&W predicted overstress conditions at full load and also the lower loads. In fact, we did not find any load that didn't have some tubes with some level of overstress.

The primary superheater outlet bank was particularly overstressed as a result of the large amount of sprayflow, which reduced the steam mass flow in the primary bank. Should AEP be confident that they will not be firing coal once the natural gas addition is completed, it is B&W's recommendation to look at the removal of primary superheater surface in an attempt to reduce the superheater sprayflow, thereby increasing the steam mass flow in the primary bank tubes which in turn would reduce tube temperatures.

In addition to significant overstresses in the primary outlet bank, the primary superheater outlet header and the steam piping to the superheater attemperators have been found to be inadequate for the natural gas conditions, based on the current surface arrangement. A review of the original design calculations determined that the header and piping are within limits up to 945°F, but the new design temperature with gas firing is predicted to be over 1010°F. B&W recommends their replacement if no modifications are made to the superheater heating surface.

Attemperators Direct contact attemperators are used to control final steam temperature by utilizing excess superheater absorption to evaporate the attemperator spray water. The spray water is introduced into the superheated steam flow between the primary and secondary superheater stages. Big Sandy Unit 1 has two (2) interstage attemperators in parallel to control main steam temperature. Each attemperator is currently designed to handle 120,000 lb/hr (240,000 lb/hr total) spray flow. At full load natural gas clean conditions, with the current surface configuration, the total predicted attemperator spray flow is 276,000 lb/hr. This is more spray flow than the original attemperator's design capacity. Higher capacity superheater attemperators are therefore recommended if no superheater surface is removed.

This unit has two (2) reheater attemperators. At full load natural gas clean conditions, the predicted reheater attemperation sprayflow is 9,400 lb/hr. This value is below the original design condition for the reheat attemperators, therefore B&W expects the existing reheat attemperators to be adequate.

Surface Removal

B&W reviewed several surface modification scenarios in order to reduce the design steam temperature leaving the primary superheater in an effort to retain the primary superheater outlet header and attemperator inlet piping when firing gas.

By removing primary superheater surface, the steam temperature leaving the primary is reduced (due to the reduced absorption in the bank). In addition, the amount of superheater sprayflow is reduced, thus increasing the steam mass flow in the primary bank which helps to reduce tube and steam temperatures in the tubes and outlet header.

By removing the two (2) lowest horizontal primary superheater rear pass banks, B&W was able to decrease the primary superheater outlet header design temperature to 954°F. This is 9°F higher than what the design calculations advise is acceptable for the existing header (945°F) and B&W recommends the replacement of the header and piping for any scenario where the design temperature is above the 945°F. Taking out additional primary horizontal surface could reduce the predicted design temperature further, however that should be weighed against the resultant increase of the flue gas temperatures through the remaining boiler components.

The surface removal lowers the metal temperatures in the primary and in addition to reducing the predicted header design temperature, slightly lowers the overstresses that were found in the primary superheater pendant bank. Unfortunately there was no surface adjustment scenario where overstresses were eliminated in that bank.

With the primary superheater surface removal, the moderate overstresses originally found in the primary superheater rear bank (tube rows 41 - 44) were eliminated.

As stated previously, B&W considers overstresses of 20% or greater to be significant and recommends the replacement of the tubes.

A summary sheet showing full load performance for both natural gas "clean" and "dirty" conditions with existing surface versus the removed primary superheater surface can be found in Appendix A. The most significant impacts to performance from removing the primary surface are:

- Reduction in superheater sprayflow
- Increases in gas temperatures through the economizer and air heater
- Decrease in boiler efficiency due mostly to the increase in exit gas temperature

With the removal of the two (2) banks of primary superheater surface, the predicted amount of superheater sprayflow is reduced such that the existing superheater attemperators should have adequate capacity under normal operation firing natural gas.

SCOPE OF SUPPLY

The following is the Scope of Supply that defines equipment required for the Natural Gas conversion at AEP Big Sandy Unit 1.

BASE SCOPE

Item 1: B&W XCL-S Burners equipped for Natural Gas firing - Qty (18)

Each burner to include:

- Externally adjustable secondary air zone spin vanes
- Externally adjustable core zone damper
- Hemispherical gas spuds
- Bellow-type expansion joint connecting the burner hemi-spud gas ring to the fuel piping
- Pitot tube relative air flow measuring device with magnehelic gage
- Provisions to accept FPS ignitor with integral SunSpot flame detector
- Two Type K permanent thermocouples to monitor core zone and burner outer sleeve temperature with two thermocouple heads
- Field insulated cover plate
- BECK electric linear actuator for automated positioning of sliding secondary air damper
- One set of burner support steel rails with furnace wall and windbox connection hardware

<u>Item 2:</u> **Class I Natural Gas Ignitors, 4 - 20 million BTU - Qty (18)**

Each ignitor is supplied complete with:

- 4.0" Stationary Guide pipe with 2.5" butterfly valve combustion air inlet. Each ignitor requires 140 SCFM of primary combustion air at 2-4"w.c. above furnace pressure
- SunSpot flame rod with high temperature extension
- Plasma Arc Ignition (PAI) spark plug with high temperature extension.
- NEMA 4X PAI power pack
- B&W plans on reusing the existing SunSpot ignitor flame detector electronic modules from the FPS oil ignitor system.
- Metal braided flex conduit assemblies for ignitor electrical connections (spark and flame rod)
- Stainless steel lined gas hose with male NPT fittings each end, swivel adaptor one end - 1.5 inch diameter x 6 long foot hose.

<u>Item 3:</u> **Main Flame Scanner System - (1) Lot**

Qty 1 - One (1) NEMA 12 Single bay Scanner Cabinet:

Qty 1 - Rack to house scanner modules including:
- Redundant 120VAC-24VDC power supplies
- Qty 18 - FPS VIR VI flame scanner modules
- Terminal Blocks for customer interface wiring with 10% spare terminals

Qty 18 - Tri-color rigid fiber optic flame scanner viewing heads

Qty 18 - Scanner head guide tubes c/w isolation valve (to prevent blowback when scanner head is withdrawn) and 1.5" NPT cooling air inlet. Each viewing head requires 35 SCFM of cooling air at minimum 4" w.c. above furnace pressure

Qty 10 - FPS scanner head junction boxes, NEMA 4, each with (9) 23' quick disconnect cables to mate with viewing heads

1 Lot - Flame scanner monitoring / tuning software. Computer and cable hardware by Others.

Item 4: Duplex Blower System

Skid mounted duplex blower assembly is sized to supply combustion/cooling air for (18) ignitors and main flame scanners on a pressure fired unit.

- Blower with direct drive, TEFC standard efficiency motors
- Check valve and butterfly isolation valve on blower outlet
- Common discharge pipe with pipe stub outlet and rubber sleeve with clamps
- Control butterfly valve on discharge
- Single loop controller for control valve
- Pressure transmitter. Supplied loose for installation in air header piping by others.
- Inlet filter-silencers
- Inlet air filter restriction gauges. Pressure switches to measure inlet pressure are available as an option. Price adder applies
- SPDT pressure switches to monitor discharge pressure, wired into starter circuits to allow automatic switchover on loss of discharge pressure. Tubing to air header piping to be installed by others.
- Circuit breaker type full voltage combination starter assemblies in NEMA 4X enclosures, each complete with switches and indicators to allow local control and monitoring of blower operation. Starters are factory mounted on blower skid and wired such that loss of discharge pressure will automatically cause the standby blower to start.
- Pre-wired connections between motors, starters and pressure switches
- 1 Lot - Air piping from blower skid to burner front components. Piping to be supplied loose for field fabrication with loose fittings and come coated with red oxide, weld-able, prime paint only.
- Qty (18) - Flex hoses to connect the air piping to the scanner and ignitor cooling air connections on each burner.

<u>Item 5</u>: Main Gas & Ignitor Supply Header Station - Qty (1)

Main Gas Header Station for Regulation of Gas Supply to the

Burner Fronts The main gas supply header station to include:

- Main gas SSV
- Gas Inlet shut off valves
- Main gas SVV
- Minimum fire bypass Pressure Reducing Valve (PRV)
- Main gas charging valve
- Fisher flow control valve
- Pressure Transmitters
- Pressure gauge with root valve
- Main gas V-Cone flow meter
- Manual drain valves (supplied loose)
- SW manual vent, test and purge valves

The ignitor supply header station would include:

- Manual shutoff valve
- Ignitor header SSV
- Ignitor header SVV
- Ignitor header PRV for ignitor fuel flow control
- Pressure transmitter
- Pressure gauge with root valve
- Ignitor gas V-Cone flow meter

<u>Item 6</u>: Local Burner & Igniter Gas Racks - Qty 18

The local burner/ignitor gas valve trains would consist of manual isolation and double block & vent valves and ancillary equipment as required for operation of one burner and one ignitor.

Main burner valve train components include:

- Manual isolation valve
- Main gas safety shut-off valves (SSV's)
- Main gas safety vent valve (SVV)
- Manual vent valve c/w limit switch
- Outlet pressure gauge with root valve
- SW test valves

Ignitor valve train components include:

- Manual isolation valve
- Ignitor gas SSV's
- Ignitor gas SVV
- Pressure Gauge with root valve
- Instrument air filter-regulator with manual shutoff valve

<u>Item 7</u>: Local Control Cabinets

Each burner/ignitor valve train would include a local control cabinet. This cabinet will be supplied loose to mount outside of the hazardous area for control and indication of the burner and ignitor.

- Ignitor start permit indicator
- Ignitor on/off (start/stop) switch
- Ignitor flame indicator
- Gas gun inserted indicator
- Burner start permit indicator
- Burner on/off (start/stop) switch
- Burner proven indicator
- Auxiliary fuel trip pushbuttons

<u>Item 8:</u> One (1) lot of 111 Primary Superheater Pendants

The replacement pendant material consists of:

- 2.50"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

<u>Item 9:</u> One (1) lot of 111 Primary Superheater Jumper Tubes

The replacement jumper tube material consists of:

- 2.50"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

<u>Item 10:</u> One (1) lot of 27 Secondary Superheater Leading Edge Tubes

The replacement SSH material consists of:

- 2.00"OD x SA213T22
- Tube ends are machined with a 37.5 degree OD bevel and 10 degree ID bevel for field welding.

A — FUEL AS FIRED

ANALYSES	BY:			
ASTM — TYPE				
ASTM — CLASS				
ASTM — GROUP				
AREA — MINE				
AREA — STATE/PROVINCE				
AREA — COUNTRY				
FUSION TEMPS - F — REDUCING ID				
FUSION TEMPS - F — REDUCING H=1/2W				
FUSION TEMPS - F — REDUCING FLUID				
FUSION TEMPS - F — OXIDIZING ID				
FUSION TEMPS - F — OXIDIZING H=1/2W				
FUSION TEMPS - F — OXIDIZING FLUID				
MISC. — SIZE				
MISC. — GRINDABILITY				
MISC. — SURFACE H2O, %				
PROXIMATE ANALYSIS - % — TOTAL MOISTURE	6.00			
PROXIMATE ANALYSIS - % — VOLATILE MATTER	32.00			
PROXIMATE ANALYSIS - % — FIXED CARBON	48.00			
PROXIMATE ANALYSIS - % — ASH	14.00			
PROXIMATE ANALYSIS - % — TOTAL	100.00			
ULTIMATE ANALYSIS — FUEL	COAL	Nat Gas		
% BY	WT	VOL		
ASH	9.57			
H2O	8.44			
C	65.36			
H2	4.70			
N2	1.16	1.13		
S	3.41			
O2	7.36			
CH4		76.69		
C2H4				
C2H6		16.54		
C3H8		4.33		
C4H10		0.94		
C5H12		0.20		
C6H14		0.09		
CO				
CO2		0.08		
SO2				
Cl + F	0.00			
TOTAL	100.00	100.00		
HHV, BTU/LB	12,034	22,518		
HHV, BTU/CUFT AT 60F, 30 IN HG		1205		

NOTES:

BY: DATE:

The Babcock & Wilcox Company

275R

ENG

B — PREDICTED PERFORMANCE (1)

No.	Item	ORIG MCR	FULL	FULL	FULL w/ SR	FULL w/ SR	
2	LOAD CONDITION	ORIG MCR	FULL	FULL	FULL w/ SR	FULL w/ SR	
3	STEAM LEAVING SH, MLB/HR	1890.00	2080.00	2080.00	2080.00	2080.00	
4	STEAM LEAVING RH1, MLB/HR	1534.00	1700.00	1700.00	1700.00	1700.00	
5	STEAM LEAVING RH2, MLB/HR	-	-	-	-	-	
6	TYPE OF FUEL	COAL	GAS DIRTY	GAS CLEAN	GAS DIRTY	GAS CLEAN	
7	EXCESS AIR LEAVING ECONOMIZER, %	18.0	10.0	10.0	10.0	10.0	
8	NO. OF BURNERS IN OPERATION	18	18	18	18	18	
9	OUTPUT PER PTC 4-1998, MKB/HR	-	2400.90	2397.30	2404.60	2400.90	
10	HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)	2523.00	2838.00	2803.00	2875.00	2828.00	
11	HEAT CREDITS, MKB/HR (PER PTC 4-1998)	0.00	0.00	0.00	0.00	0.00	
12	FUEL INPUT, MKB/HR	2410.00	2818.10	2802.50	2833.70	2814.30	
13	QUANTITY - MLB/HR — FUEL FLOW (MCF/HR IF GAS)	200.80	2338.60	2325.80	2351.60	2335.50	
14	FLUE GAS ENTERING AIR HEATER	2330.00	2418.10	2404.80	2431.60	2414.90	
15	TOTAL AIR TO BURNING EQUIPMENT	1889.00	2251.30	2238.90	2263.80	2248.30	
16	SECONDARY AIR LEAVING AH	-	-	-	-	-	
17	PRIMARY AIR LEAVING AH	-	-	-	-	-	
18	TEMPERING AIR	-	-	-	-	-	
19	AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-	-	-	-	
20	AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-	-	-	-	
21	AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-	-	-	-	
22	AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-	-	-	-	
23	SUPERHEAT SPRAY FLOW	40.30	219.40	276.00	153.60	229.10	
24	REHEAT SPRAY FLOW (RH1/RH2)	0/0	12.3/0	9.4/0	15.1/0	12.3/0	
25	PRESSURE - PSIG — STEAM AT SH OUTLET	2500	2500	2500	2500	2500	
26	STEAM AT RH1 INLET	535	531	531	531	531	
27	STEAM AT RH2 INLET	-	-	-	-	-	
28	DROP — REHEATER 1	25	39	39	39	39	
29	DROP — REHEATER 2	-	-	-	-	-	
30	DROP — ECONOMIZER (PLUS FURNACE IF UP)	25	30	30	30	30	
31	DROP — DRUM OR VSS TO SH OUTLET	150	182	182	182	182	
32	TEMPERATURE - DEG. F — STEAM — LEAVING SUPERHEATER	1050	1050	1050	1050	1050	
33	STEAM — LEAVING REHEATER 1	1050	1050	1050	1050	1050	
34	STEAM — ENTERING REHEATER 1	675	658	661	655	658	
35	STEAM — LEAVING REHEATER 2	-	-	-	-	-	
36	STEAM — ENTERING REHEATER 2	-	-	-	-	-	
37	WATER — ENTERING ECONOMIZER	526	523	523	523	523	
38	GAS (MHVT) — LEAVING ECONOMIZER	702	711	668	756	698	
39	GAS (MHVT) — LEAVING AH (EXCL. LKG)	300	314	299	329	309	
40	GAS (MHVT) — LEAVING AH (INCL. LKG)	-	-	-	-	-	
41	GAS (MHVT) — ENTERING SSH INLET (24" SPACING)	-	-	-	-	-	
42	GAS (MHVT) — ENTERING 12" OR LOWER SPACING	-	-	-	-	-	
43	AIR — ENTERING PRI. AIR HEATER (1)	-	-	-	-	-	
44	AIR — ENTERING SEC. AIR HEATER (1)	-	-	-	-	-	
45	AIR — LEAVING AIR HEATER (SEC)	-	-	-	-	-	
46	AIR — LEAVING AIR HEATER (PRI)	-	-	-	-	-	
47	FUEL — TO BURNING EQUIPMENT	-	-	-	-	-	
48	RESISTANCE - IN. H2O — GAS — FURNACE & CONVECTION BANKS	-	-	-	-	-	
49	GAS — FLUES TO AH OUTLET	-	-	-	-	-	
50	GAS — AIR HEATER	-	-	-	-	-	
51	GAS — SCR	-	-	-	-	-	
52	GAS — TOTAL FROM FURNACE TO STACK	-	-	-	-	-	
53	PRI AIR — AIR HEATER	-	-	-	-	-	
54	PRI AIR — DUCTS & FLOW METER	-	-	-	-	-	
55	PRI AIR — PULVERIZERS	-	-	-	-	-	
56	PRI AIR — FUEL PIPING TO BURNERS	-	-	-	-	-	
57	PRI AIR — BURNERS	-	-	-	-	-	
58	PRI AIR — TOTAL	-	-	-	-	-	
59	SEC AIR — FUEL BURNERS & WINDBOX	-	-	-	-	-	
60	SEC AIR — DUCTS & FLOW METER	-	-	-	-	-	
61	SEC AIR — AIR HEATER	-	-	-	-	-	
62	SEC AIR — TOTAL FROM FD FAN TO FURNACE	-	-	-	-	-	
63	HEAT LOSSES, % — DRY GAS	3.980	3.220	2.950	3.490	3.130	
64	H2 & H2O IN FUEL	4.370	9.810	9.740	9.870	9.790	
65	MOISTURE IN AIR	0.100	0.080	0.080	0.090	0.080	
66	UNBURNED COMBUSTIBLE IN RESIDUE	0.480	0.000	0.000	0.000	0.000	
67	RADIATION	0.160	0.190	0.190	0.190	0.190	
68	SENSIBLE HEAT IN REFUSE	0.000	0.000	0.000	0.000	0.000	
69	MANUFACTURER'S MARGIN	1.500	1.500	1.500	1.500	1.500	
70	OTHER LOSSES (UNMEASURED)	0.000	0.000	0.000	0.000	0.000	
71	TOTAL LOSSES	10.590	14.800	14.460	15.140	14.690	
72	HEAT CREDITS, % — ENTERING DRY AIR	0.000	0.000	0.000	0.000	0.000	
73	MOISTURE IN AIR	0.000	0.000	0.000	0.000	0.000	
74	SENSIBLE HEAT IN FUEL	0.000	0.000	0.000	0.000	0.000	
75	AUXILIARY EQUIPMENT POWER	0.000	0.000	0.000	0.000	0.000	
76	OTHER CREDITS (UNMEASURED)	0.000	0.000	0.000	0.000	0.000	
77	TOTAL CREDITS	0.000	0.000	0.000	0.000	0.000	
78	ASME PTC 4-1998 FUEL EFFICIENCY, %	89.410	85.200	85.540	84.860	85.310	
79	PULV & FEEDER — NO. IN USE PER BOILER	6	-	-	-	-	
80	PULV & FEEDER — % THRU 200 U.S.S. SIEVE	70.0	-	-	-	-	

81 PREDICTED PERFORMANCE IS BASED ON CONDITIONS AND EQUIPMENT SHOWN ON THIS SUMMARY SHEET AND ON GENERAL ARRANGEMENT DRAWING(S)

82 POUNDS WATER PER POUND COMBUSTION AIR = 0.0130 AND BAROMETRIC PRESSURE = 29.92 IN HG

C — EQUIPMENT PER UNIT

No.	Item	
2	TYPE RB-364	
3	SIZE	
4		
5	DRUM DESIGN PRESSURE (MASTER STAMPING IF UP), PSIG	2800
6		
7	PRESSURE PART HEATING SURFACE — FURN — WATER COOLED SCREEN (CIRCUM.)	
8	WATER COOLED (PROJECTED)	
9	SUPERHEATER (CIRCUMFERENTIAL)	
10	SUPERHEATER (PROJECTED)	
11		
12	TOTAL FURNACE HEATING SURFACE	
13	CONV — SATURATED (CIRCUMFERENTIAL)	
14	SUPERHEATER (CIRCUMFERENTIAL)	
15		
16		
17	ECONOMIZER	
18	TOTAL CONVECTION HEATING SURFACE	
19	TOTAL FURN & CONV PRESSURE PART HTG SURF	
20	FLAT PROJECTED FURNACE HEATING SURFACE:	
21	TO FACE OF SH (24" CL)	
22	SQ FT — TO FACE OF CONVECTION SURFACE	
23	FURNACE VOLUME, CUBIC FEET	
24	AIR HEATER — TYPE REGENERATIVE QUANTITY	
25	TOTAL HEATING SURFACE, SQUARE FEET	
26		
27		
28	FUEL BURNER — TYPE	XCL-S PROPOSED
29	NO.	18
30		
31	PULV — TYPE:	
32	SIZE	
33		
34	NUMBER	
35–38		
39	STEAM TEMP. CONTROL	
40	SH & RH ATTEMPERATION	
41		
42	EXCESS AIR	
43–45		
46	UNIT CONSTR. FEATURES	PARALLEL PASS HORIZONTAL CONVECTION SURF
47–54		

REVISIONS

NO	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sandy Unit 1
Natural Gas Conversion
SR= With SH Surf Removed

REVISIONS

REV	DESCRIPTION	DATE	APPROVAL

B&W DWG No.	TITLE
B0233970	P&ID DRAWING INDEX
B0233971	P&ID IDENTIFICATION & TAGGING
B0233972	P&ID SYMBOLS & NOMENCLATURE
B0233973	P&ID NATURAL GAS BURNER & IGNITER SUPPLY HEADERS
B0233974	P&ID NATURAL GAS BURNER & IGNITER VALVE RACKS
B0233975	P&ID NATURAL GAS BURNER
B0233976	P&ID SCANNER COOLING AIR BLOWERS

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO

PROCESS & INSTRUMENTATION DIAGRAM
DRAWING INDEX

DWN JW HEVENER
CHK'D AK ROSS
APPV'D JE BOLLINGER
DATE 9.17.12
SCALE NONE

Type	PROJECT
Dist.Cust.	YES
Dist.Erec.	NO
Dist.MFG.	NO

User Defined Field 591-0999
ORIG. CONTRACT NO. 334-0364
– DO NOT SCALE –
USE DIMENSIONS ONLY

PROJECT NO. 0635-275R
COA A00000
DWG. NO. B0233970 E
REV. 00

(01/28/10)

REVISIONS

REV	DESCRIPTION	DATE	APPROVE

INSTRUMENT IDENTIFICATION LETTERS

	FIRST LETTER		SUCCEEDING LETTERS		
	MEASURED OR INITIATING VARIABLE	MODIFIER	READOUT OR PASSIVE FUNCTION	OUTPUT FUNCTION	MODIFIER
A	Analysis		Alarm		
B	Burner, Combustion		User's Choice	User's Choice	User's Choice
C	User's Choice			Control	
D	Density	Differential			
E	Voltage		Sensor (Primary Element)		
F	Flow Rate	Ratio (Fraction)			
G	User's Choice		Glass, Viewing Device		
H	Hand				High, Open
I	Current (Electric)		Indicate		
J	Power	Scan			
K	Time, Time Schedule	Time Rate of Change		Control Station	
L	Level		Light		Low, Closed
M	User's Choice	Momentary			Middle, Intermediate
N	User's Choice		User's Choice	User's Choice	User's Choice
O	User's Choice		Orifice, Restriction		
P	Pressure, Vacuum		Point (Test) Connection		
Q	Quantity	Integrate, Totalize			
R	Radiation		Record		
S	Speed, Frequency	Safety		Switch	
T	Temperature			Transmit	
U	Multivariable		Multifunction	Multifunction	Multifunction
V	Vibration, Mechanical Analysis			Valve, Damper, Louver	
W	Weight, Force		Well		
X	Unclassified	X Axis	Unclassified	Unclassified	Unclassified
Y	Event, State or Presence	Y Axis		Relay, Compute, Convert	
Z	Position, Dimension	Z Axis		Driver, Actuator, Unclassified Final Control Element	

SYSTEM CODES

AFS	ACID FEED (ADDITIVES) SYSTEM
ABP	ABSORPTION PLUS ADDITIVE SYSTEM
ABS	ABSORBER/SCRUBBER
AHS	ASH HANDLING SYSTEM
AIG	AMMONIA INJECTION GRID
AMS	AMMONIA (UNLOADING, STORAGE & HANDLING) SYSTEM
APS	ABSORBER PURGE SYSTEM
ARS	ABSORBER RECYCLE SYSTEM
ASW	ASH WATER
AXS	AUXILIARY STEAM
BAG	BOILER AIR & GAS
BCA	BOILER COMBUSTION AIR
BFW	BOILER FEEDWATER
BMP	BALL MILL PRODUCT
BST	BOILER STEAM
CAS	COOLING AIR SYSTEM
CFS	CHEMICAL FEED SYSTEM
CHS	COAL HANDLING SYSTEM
CKS	CAKE WASH SYSTEM
CLS	CLOTH WASH SYSTEM
CND	CONDENSATE & CONDENSER
COP	CATALYST OUTAGE PROTECTION SYSTEM (COPS)
CWS	COOLING WATER SYSTEM
DAS	DILUTION AIR SYSTEM
EQS	EMERGENCY QUENCH SYSTEM
FAS	FLY ASH SYSTEM
FFS	FILTER FEED SYSTEM
FGS	FLUE GAS SYSTEM
FHS	FUEL HANDLING SYSTEM
FLA	FLUIDIZING AIR
FOS	FUEL OIL SYSTEM
FPS	FIRE PROTECTION SYSTEM
FSS	FEED SLURRY SYSTEM
FWS	FILTRATE WATER SYSTEM
GHS	GYPSUM HANDLING SYSTEM
GSS	GYPSUM SLURRY SYSTEM
HJS	HYDROJET SYSTEM
IAS	INSTRUMENT AIR SUPPLY
IST	INERTING STEAM
LDS	DRY (PEBBLE) LIME SYSTEM
LHS	LIMESTONE HANDLING SYSTEM
LOS	LUBE OIL SYSTEM
LSS	LIMESTONE SLURRY SYSTEM
MAS	MER PLUS ADDITIVE SYSTEM
MEW	MIST ELIMINATOR WASH WATER
MSS	MAIN STEAM SYSTEM
NGS	NATURAL GAS SYSTEM
NOS	NOX REDUCTION SYSTEM
OAS	OXIDATION AIR SYSTEM
ORA	OVERFIRE AIR
PAC	PAC INJECTION SYSTEM
PAF	PRIMARY AIR FLOW
PCS	PULVERIZED COAL SYSTEM
PJF	FABRIC FILTER SYSTEM
PWS	POTABLE WATER SYSTEM
RHS	REHEAT STEAM SYSTEM
RPS	REAGENT PREP SYSTEM
RSS	RECYCLE SLURRY SYSTEM
RWS	RECLAIM WATER SYSTEM
SAF	SECONDARY AIR FLOW
SAS	SERVICE AIR SYSTEM
SBS	SOOT BLOWING SYSTEM
SHS	SONIC HORNS SYSTEM
SIS	SORBENT INJECTION SYSTEM
SLA	SEAL AIR
STM	STEAM
SWS	SERVICE WATER SYSTEM
VDS	VENTS AND DRAINS
VFS	VACUUM FILTER SKID/SYSTEM
WWT	WASTE WATER TREATMENT

INSTRUMENT CODES

AE	ANALYZER ELEMENT
AT	ANALYZER TRANSMITTER
BE	FLAME ELEMENT
BT	FLAME INTENSITY
DE	DENSITY ELEMENT
DT (DIT)	DENSITY TRANSMITTER
FE	FLOW ELEMENT
FI	FLOW INDICATOR
FO	FLOW ORIFICE
FS (HH,H,M,L,LL)	FLOW SWITCH
FT (FIT)	FLOW TRANSMITTER
IT	CURRENT TRANSMITTER
JT	POWER TRANSMITTER
LI	LEVEL INDICATOR
LS (HH,H,M,L,LL)	LEVEL SWITCH
LT (LIT)	LEVEL TRANSMITTER
PDI	DIFFERENTIAL PRESSURE INDICATOR
PDS (HH,H,M,L,LL)	DIFFERENTIAL PRESSURE SWITCH
PDT (PDIT)	DIFFERENTIAL PRESSURE TRANSMITTER
PI	PRESSURE INDICATOR
PS (HH,H,M,L,LL)	PRESSURE SWITCH
PT (PIT)	PRESSURE TRANSMITTER
SS (HH,H,M,L,LL)	SPEED SWITCH
ST (SIT)	SPEED TRANSMITTER
TE	TEMPERATURE ELEMENT
TI	TEMPERATURE INDICATOR
TS (HH,H,M,L,LL)	TEMPERATURE SWITCH
TT (TIT)	TEMPERATURE TRANSMITTER
TW	THERMOWELL
VE	VIBRATION ELEMENT
VT (VIT)	VIBRATION TRANSMITTER
WE	LOAD CELL
WT (WIT)	WEIGHT TRANSMITTER
XS	GENERAL SWITCH
ZS	PROXIMITY SWITCH

TAG NUMBER LEGEND

X-XXX-XXX-XXXX

UNIT NUMBER (NOT DISPLAYED)
SYSTEM CODE
UNIQUE SEQUENCE NUMBER
EQUIPMENT TYPE
MANUAL VALVE TYPE

SYSTEM CODE — XXX
UNIQUE SEQUENCE NUMBER — XXXX
XXX — INSTRUMENT TYPE
CONTROL/AUTOMATED VALVE TYPE

TERMINAL POINT LEGEND

T-XXX

TERMINAL POINT
UNIQUE SEQUENCE NUMBER

EQUIPMENT CODES

ABS	ABSORBER
ACT	ACTIVATOR
ACU	ACCUMULATOR
AGT	AGITATOR
AHT	AIR HEATER
AIG	AMMONIA INJECTION GRID
ATM	ATOMIZER
BGH	BAGHOUSE
BIN	BIN
BLO	BLOWER
BMC	BALL MILL CLUTCH
BML	BALL MILL
BOX	BOX
BRL	BARREL
BRN	BURNER
CLF	COOLING FAN
CLR	COOLER
CLT	CLUTCH
CPL	CONTROL PANEL
CPR	COMPRESSOR
CRU	CRUSHER
CSF	CLASSIFIER
CVR	CONVEYOR
DCL	DUST COLLECTOR
DMP	DAMPER
DRM	DRUM
DRV	DRIVE
DRY	DRYER
EDC	EDUCTOR
EES	EMERGENCY EYEWASH SYSTEM
EXJ	EXPANSION JOINT
FAN	FAN
FDR	FEEDER
FLT	FILTER
GBX	GEAR BOX
GRD	GEAR REDUCER
HMD	HUMIDIFIER
HPR	HOPPER
HPS	HYDRAULIC SYSTEM
HRL	HOSE REAL
HTR	HEATER
HXR	HEAT EXCHANGER
HYC	HYDROCLONE
HYD	HYDROJET
IGN	IGNITER
JBX	JUNCTION BOX
MFD	MANIFOLD
MIX	AMMONIA AIR MIXER
MXR	MIXER
MTR	MOTOR
PDG	PINION DRIVE GEAR
PLV	PULVERIZER
PMP	PUMP
RCV	RECEIVER
RFO	RESTRICTIVE ORIFACE
RVR	RESERVOIR
SBL	SOOTBLOWER
SCB	SCRUBBER
SCN	SCREEN
SCR	SELECTIVE CATALYTIC REDUCTION
SDA	SPRAY DRYER ABSORBER
SEP	SEPARATOR
SGN	STEAM GENERATOR
SIL	SILO
SIS	SORBENT INJECTION SYSYEM
SKD	SKID
SLC	SILENCER
SLK	SLAKER
SMP	SUMP
SNK	SINK
STP	STANDPIPE
STR	STRAINER
TNK	TANK
TRP	STEAM TRAP
VAP	VAPORIZER
VBF	VACUUM BELT FILTER
VDF	VACUUM DRUM FILTER
VFD	VARIABLE FREQUENCY DRIVE
VTU	VENTURI

VALVE CODES

CHK	CHECK VALVE
FCV	FLOW CONTROL VALVE
HV	MANUAL VALVE
LCV	LEVEL CONTROL VALVE
MOV	MOTOR OPERATED VALVE
PCV	PRESSURE CONTROL/REGULATING VALVE
PSV	PRESSURE (SAFETY) RELIEF VALVE
SOV	SOLENOID OPERATED VALVE
TCV	TEMPERATURE CONTROL VALVE
XV	AUTOMATED VALVE/DAMPER

NOTES:

1. FOR PROCESS & INSTRUMENTATION DIAGRAM – DRAWING INDEX. SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM – SYMBOLS & NOMENCLATURE, SEE B&W DRAWING B0233972.

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

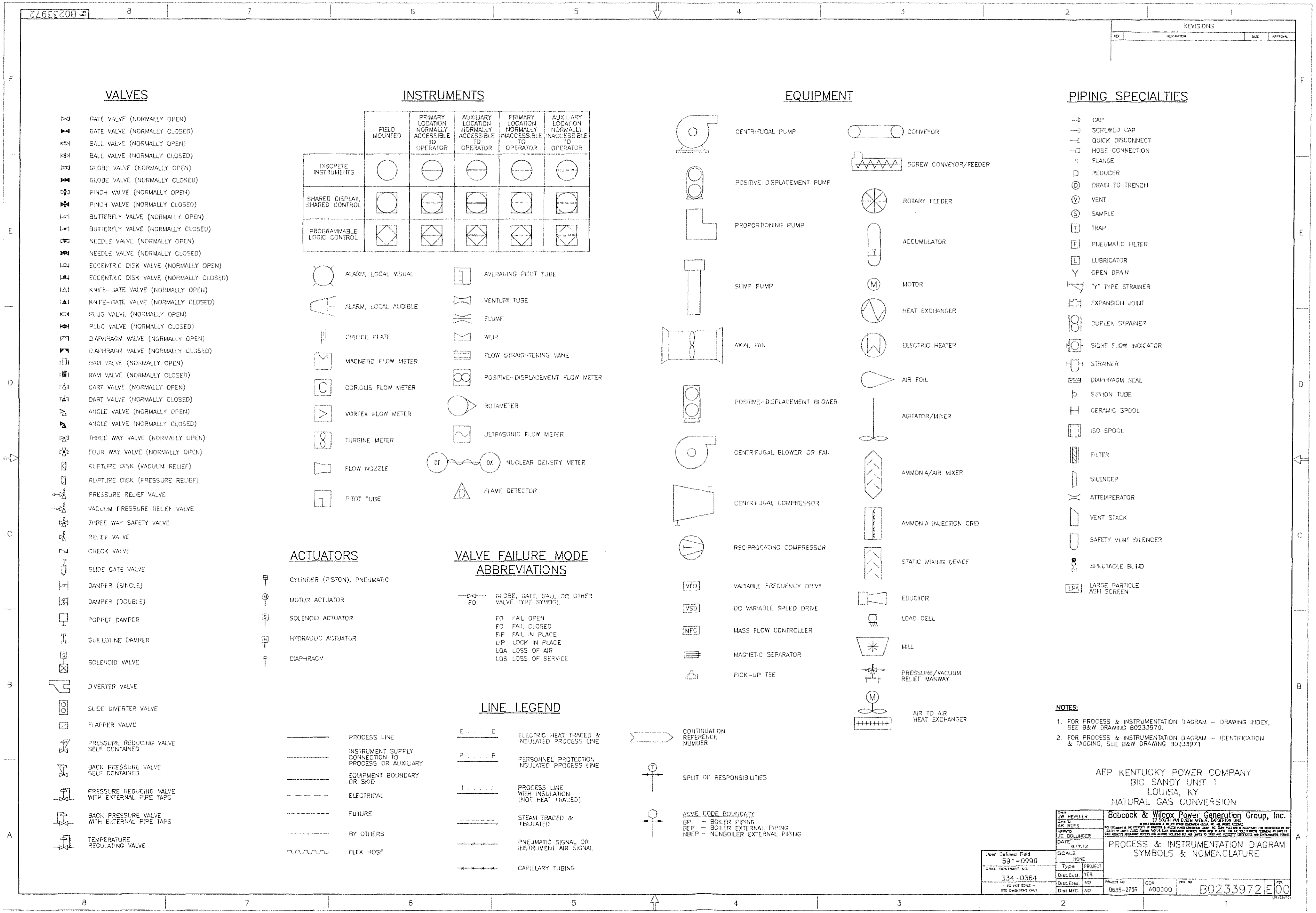
DWN JW HEVENER
CHK'D AK ROSS
APPV'D JE BOLLINGER
DATE 9.17.12
SCALE NONE
Type PROJECT
Dist.Cust. YES
Dist.Erec. NO
Dist.MFG. NO

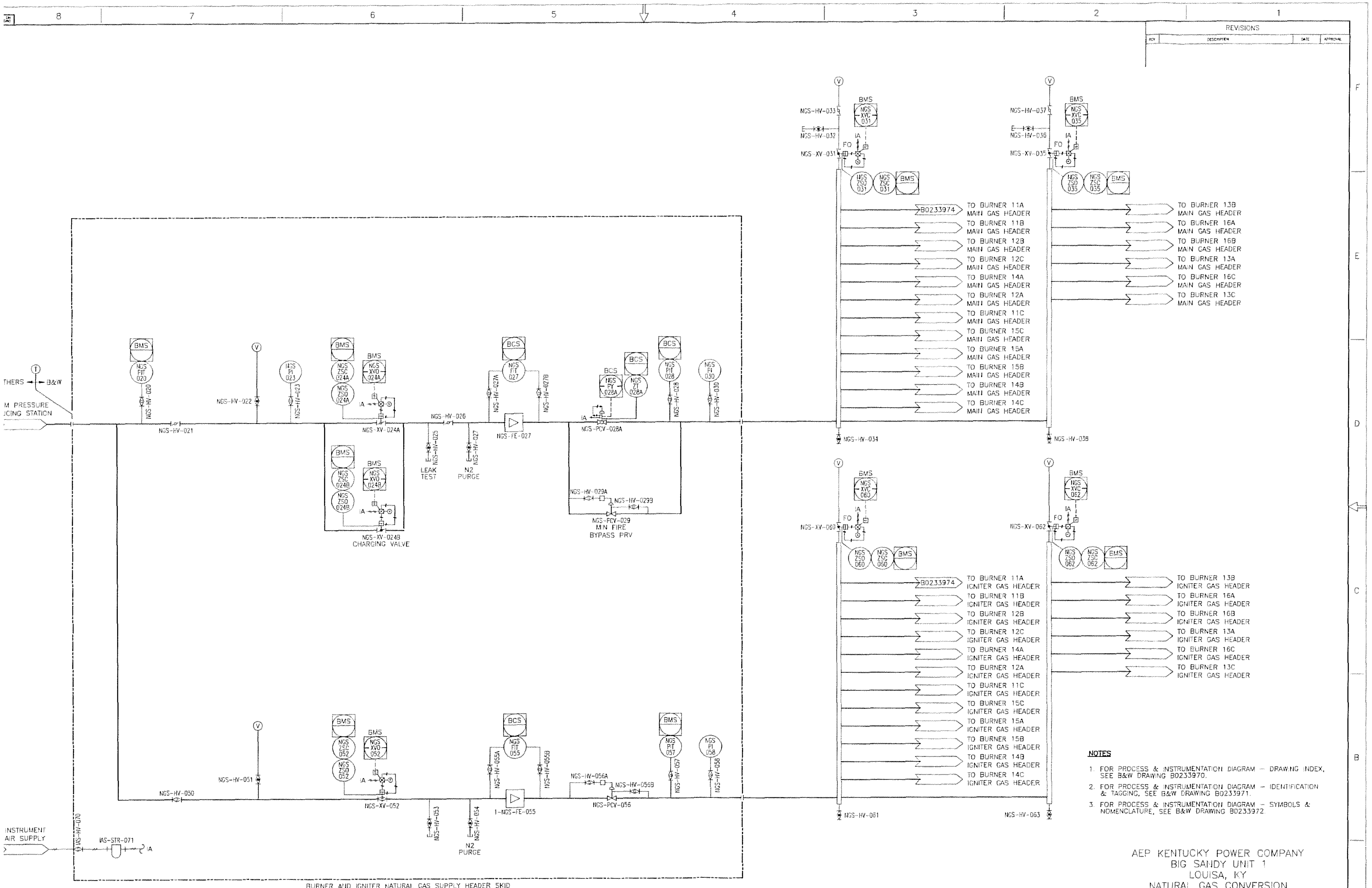
User Defined Field 591-0999
ORIG. CONTRACT NO. 344-0364
– DO NOT SCALE – USE DIMENSIONS ONLY

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO

PROCESS & INSTRUMENTATION DIAGRAM
IDENTIFICATION & TAGGING

PROJECT NO. 0635-275R
COA A00000
DWG. NO. B0233971 E
REV. 00
(01/28/10)


B0233972
REVISIONS
VALVES
GATE VALVE (NORMALLY OPEN)
GATE VALVE (NORMALLY CLOSED)
BALL VALVE (NORMALLY OPEN)
BALL VALVE (NORMALLY CLOSED)
GLOBE VALVE (NORMALLY OPEN)
GLOBE VALVE (NORMALLY CLOSED)
PINCH VALVE (NORMALLY OPEN)
PINCH VALVE (NORMALLY CLOSED)
BUTTERFLY VALVE (NORMALLY OPEN)
BUTTERFLY VALVE (NORMALLY CLOSED)
NEEDLE VALVE (NORMALLY OPEN)
NEEDLE VALVE (NORMALLY CLOSED)
ECCENTRIC DISK VALVE (NORMALLY OPEN)
ECCENTRIC DISK VALVE (NORMALLY CLOSED)
KNIFE-GATE VALVE (NORMALLY OPEN)
KNIFE-GATE VALVE (NORMALLY CLOSED)
PLUG VALVE (NORMALLY OPEN)
PLUG VALVE (NORMALLY CLOSED)
DIAPHRAGM VALVE (NORMALLY OPEN)
DIAPHRAGM VALVE (NORMALLY CLOSED)
RAM VALVE (NORMALLY OPEN)
RAM VALVE (NORMALLY CLOSED)
DART VALVE (NORMALLY OPEN)
DART VALVE (NORMALLY CLOSED)
ANGLE VALVE (NORMALLY OPEN)
ANGLE VALVE (NORMALLY CLOSED)
THREE WAY VALVE (NORMALLY OPEN)
FOUR WAY VALVE (NORMALLY OPEN)
RUPTURE DISK (VACUUM RELIEF)
RUPTURE DISK (PRESSURE RELIEF)
PRESSURE RELIEF VALVE
VACUUM PRESSURE RELIEF VALVE
THREE WAY SAFETY VALVE
RELIEF VALVE
CHECK VALVE
SLIDE GATE VALVE
DAMPER (SINGLE)
DAMPER (DOUBLE)
POPPET DAMPER
GUILLOTINE DAMPER
SOLENOID VALVE
DIVERTER VALVE
SLIDE DIVERTER VALVE
FLAPPER VALVE
PRESSURE REDUCING VALVE SELF CONTAINED
BACK PRESSURE VALVE SELF CONTAINED
PRESSURE REDUCING VALVE WITH EXTERNAL PIPE TAPS
BACK PRESSURE VALVE WITH EXTERNAL PIPE TAPS
TEMPERATURE REGULATING VALVE
INSTRUMENTS
FIELD MOUNTED
PRIMARY LOCATION NORMALLY ACCESSIBLE TO OPERATOR
AUXILIARY LOCATION NORMALLY ACCESSIBLE TO OPERATOR
PRIMARY LOCATION NORMALLY INACCESSIBLE TO OPERATOR
AUXILIARY LOCATION NORMALLY INACCESSIBLE TO OPERATOR
DISCRETE INSTRUMENTS
SHARED DISPLAY, SHARED CONTROL
PROGRAMMABLE LOGIC CONTROL
ALARM, LOCAL VISUAL
ALARM, LOCAL AUDIBLE
ORIFICE PLATE
MAGNETIC FLOW METER
CORIOLIS FLOW METER
VORTEX FLOW METER
TURBINE METER
FLOW NOZZLE
PITOT TUBE
AVERAGING PITOT TUBE
VENTURI TUBE
FLUME
WEIR
FLOW STRAIGHTENING VANE
POSITIVE-DISPLACEMENT FLOW METER
ROTAMETER
ULTRASONIC FLOW METER
DT
DX
NUCLEAR DENSITY METER
FLAME DETECTOR
ACTUATORS
CYLINDER (PISTON), PNEUMATIC
MOTOR ACTUATOR
SOLENOID ACTUATOR
HYDRAULIC ACTUATOR
DIAPHRAGM
VALVE FAILURE MODE ABBREVIATIONS
FO
GLOBE, GATE, BALL OR OTHER VALVE TYPE SYMBOL
FO FAIL OPEN
FC FAIL CLOSED
FIP FAIL IN PLACE
LIP LOCK IN PLACE
LOA LOSS OF AIR
LOS LOSS OF SERVICE
LINE LEGEND
PROCESS LINE
INSTRUMENT SUPPLY CONNECTION TO PROCESS OR AUXILIARY
EQUIPMENT BOUNDARY OR SKID
ELECTRICAL
FUTURE
BY OTHERS
FLEX HOSE
E . . . . E
ELECTRIC HEAT TRACED & INSULATED PROCESS LINE
P . . . . P
PERSONNEL PROTECTION INSULATED PROCESS LINE
I I
PROCESS LINE WITH INSULATION (NOT HEAT TRACED)
STEAM TRACED & INSULATED
PNEUMATIC SIGNAL OR INSTRUMENT AIR SIGNAL
CAPILLARY TUBING
CONTINUATION REFERENCE NUMBER
SPLIT OF RESPONSIBILITIES
ASME CODE BOUNDARY
BP - BOILER PIPING
BEP - BOILER EXTERNAL PIPING
NBEP - NONBOILER EXTERNAL PIPING
EQUIPMENT
CENTRIFUGAL PUMP
POSITIVE DISPLACEMENT PUMP
PROPORTIONING PUMP
SUMP PUMP
AXIAL FAN
POSITIVE-DISPLACEMENT BLOWER
CENTRIFUGAL BLOWER OR FAN
CENTRIFUGAL COMPRESSOR
RECIPROCATING COMPRESSOR
VFD
VARIABLE FREQUENCY DRIVE
VSD
DC VARIABLE SPEED DRIVE
MFC
MASS FLOW CONTROLLER
MAGNETIC SEPARATOR
PICK-UP TEE
CONVEYOR
SCREW CONVEYOR/FEEDER
ROTARY FEEDER
ACCUMULATOR
M
MOTOR
HEAT EXCHANGER
ELECTRIC HEATER
AIR FOIL
AGITATOR/MIXER
AMMONIA/AIR MIXER
AMMONIA INJECTION GRID
STATIC MIXING DEVICE
EDUCTOR
LOAD CELL
MILL
PRESSURE/VACUUM RELIEF MANWAY
M
AIR TO AIR HEAT EXCHANGER
PIPING SPECIALTIES
CAP
SCREWED CAP
QUICK DISCONNECT
HOSE CONNECTION
FLANGE
REDUCER
DRAIN TO TRENCH
VENT
SAMPLE
TRAP
PNEUMATIC FILTER
LUBRICATOR
OPEN DRAIN
"Y" TYPE STRAINER
EXPANSION JOINT
DUPLEX STRAINER
SIGHT FLOW INDICATOR
STRAINER
DIAPHRAGM SEAL
SIPHON TUBE
CERAMIC SPOOL
ISO SPOOL
FILTER
SILENCER
ATTEMPERATOR
VENT STACK
SAFETY VENT SILENCER
SPECTACLE BLIND
LPA
LARGE PARTICLE ASH SCREEN
NOTES:
1. FOR PROCESS & INSTRUMENTATION DIAGRAM - DRAWING INDEX, SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM - IDENTIFICATION & TAGGING, SEE B&W DRAWING B0233971.
AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION
Babcock & Wilcox Power Generation Group, Inc.
PROCESS & INSTRUMENTATION DIAGRAM
SYMBOLS & NOMENCLATURE
JW HEVENER
AK ROSS
JE BOLLINGER
9.17.12
NONE
User Defined Field
591-0999
334-0364
0635-275R
A00000
B0233972
E
00



NOTES

1. FOR PROCESS & INSTRUMENTATION DIAGRAM – DRAWING INDEX, SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM – IDENTIFICATION & TAGGING, SEE B&W DRAWING B0233971.
3. FOR PROCESS & INSTRUMENTATION DIAGRAM – SYMBOLS & NOMENCLATURE, SEE B&W DRAWING B0233972.

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

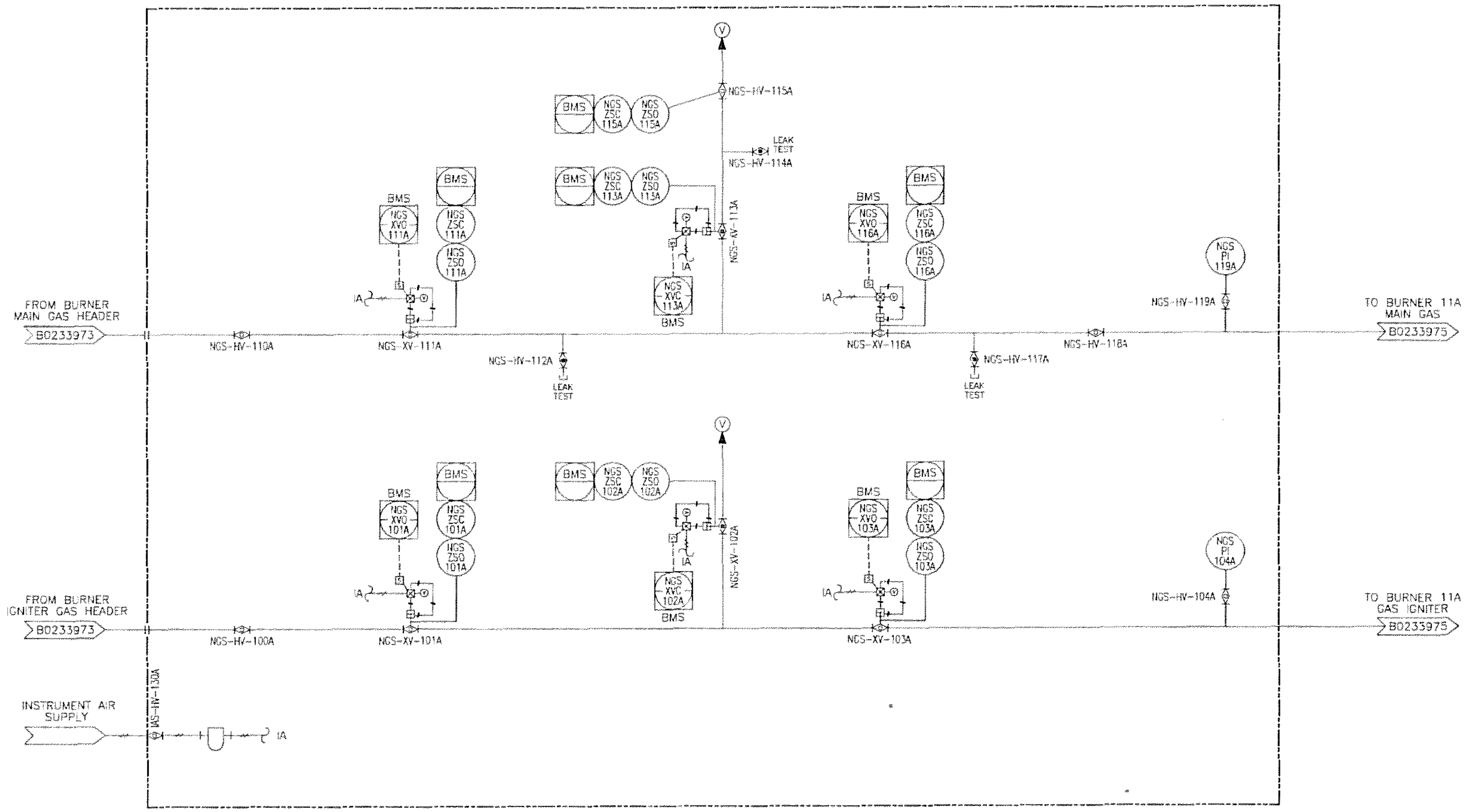
Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO

PROCESS & INSTRUMENTATION DIAGRAM
NATURAL GAS BURNER & IGNITER
SUPPLY HEADERS

DWN	JW HEVENER
CHK'D	AK ROSS
APPV'D	JE BOLLINGER
DATE	9.17.12
SCALE	NONE
Type	PROJECT
Dist.Cust.	YES
Dist.Erec.	NO
Dist.MFG.	NO
User Defined Field	591-0999
ORIG. CONTRACT NO	334-0364
PROJECT NO.	0635-275R
CDA	A00000
DWG. NO.	B0233973
REV.	E 00

– DO NOT SCALE –
USE DIMENSIONS ONLY

REVISIONS			
REV	DESCRIPTION	DATE	APPROVAL



BURNER 11A VALVE RACK ASSEMBLY

NOTES

1. FOR PROCESS & INSTRUMENTATION DIAGRAM – DRAWING INDEX, SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM – IDENTIFICATION & TAGGING, SEE B&W DRAWING B0233971.
3. FOR PROCESS & INSTRUMENTATION DIAGRAM – SYMBOLS & NOMENCLATURE, SEE B&W DRAWING B0233972.
4. BURNER 11A SHOWN. TYPICAL FOR BURNERS 11B–C, 12A–C, 13A–C, 14A–C, 15A–C AND 16A–C EXCEPT FOR TAG NUMBER SUFFIX.

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

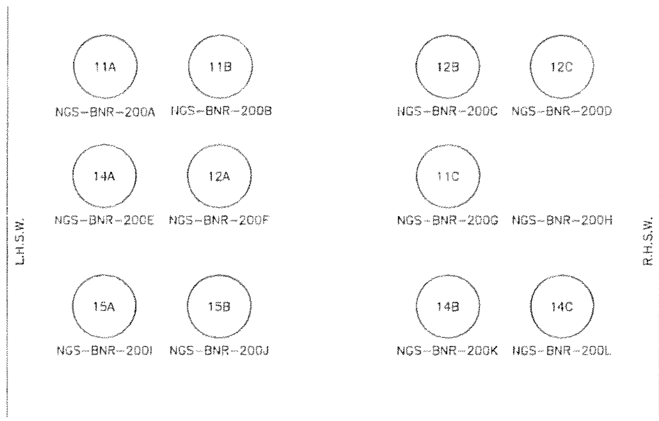
DWN JW HEVENER		Babcock & Wilcox Power Generation Group, Inc. 20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO
CHK'D AK ROSS		
APPV'D JE BOLLINGER		
DATE 9.17.12		PROCESS & INSTRUMENTATION DIAGRAM NATURAL GAS BURNER & IGNITER VALVE RACKS
SCALE NONE		
Type	PROJECT	
Dist.Cust.	YES	
Dist.Erec.	NO	PROJECT NO. 0635-275R — COA A00000 — DWG. NO. B0233974 E — REV. 00
Dist.MFG.	NO	

User Defined Field 591-0999
ORIG. CONTRACT NO. 334-0364
– DO NOT SCALE – USE DIMENSIONS ONLY

(01/29/10)

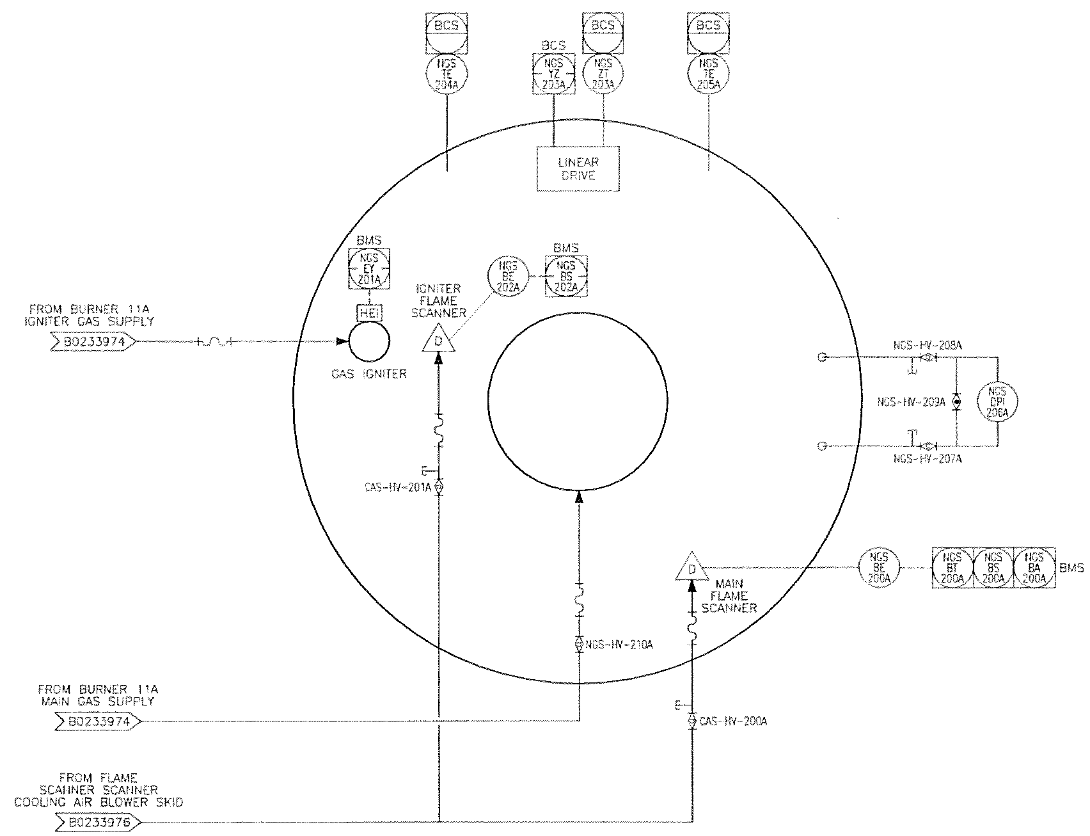
REVISIONS

REV	DESCRIPTION	DATE	APPROVAL



FURNACE FRONT WALL
NATURAL GAS BURNERS

FURNACE REAR WALL
NATURAL GAS BURNERS



BURNER 11A
NGS-BNR-200A

NOTES:

1. FOR PROCESS & INSTRUMENTATION DIAGRAM – DRAWING INDEX, SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM – IDENTIFICATION & TAGGING, SEE B&W DRAWING B0233971.
3. FOR PROCESS & INSTRUMENTATION DIAGRAM – SYMBOLS & NOMENCLATURE, SEE B&W DRAWING B0233972.
4. BURNER 11A SHOWN. TYPICAL FOR BURNERS 11B–C, 12A–C, 13A–C, 14A–C, 15A–C AND 16A–C EXCEPT FOR TAG NUMBER SUFFIX.

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

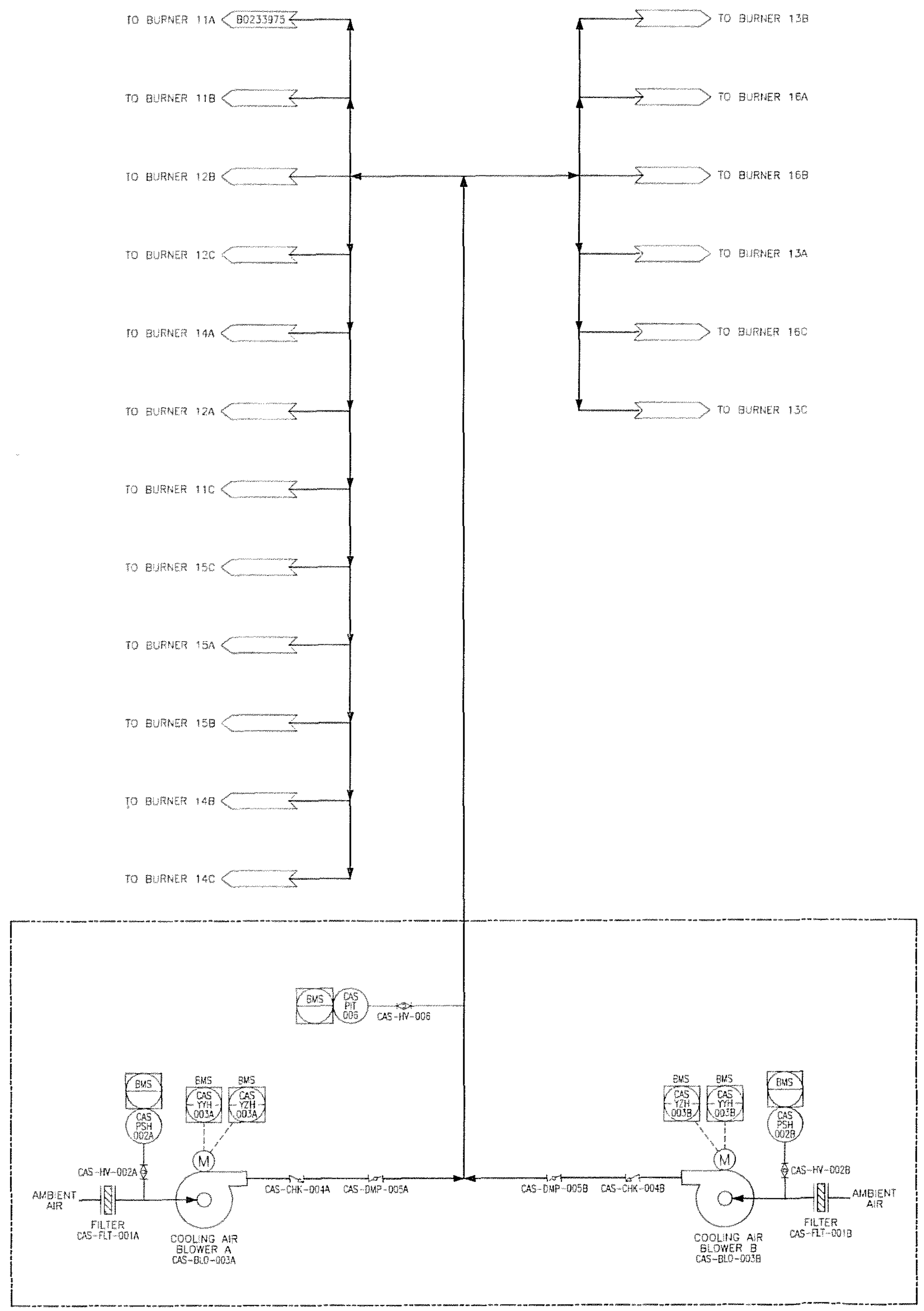
Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO

PROCESS & INSTRUMENTATION DIAGRAM
NATURAL GAS BURNER

DWN	JW HEVENER
CHK'D	AK ROSS
APPV'D	JE BOLLINGER
DATE	9.17.12
SCALE	NONE
Type	PROJECT
Dist.Cust.	YES
Dist.Erec.	NO
Dist.MFG.	NO
User Defined Field	591-0999
ORIG. CONTRACT NO	334-0364
PROJECT NO.	0635-275R
COA	A00000
DWG. NO.	B0233975 E
REV.	00

– DO NOT SCALE – USE DIMENSIONS ONLY

(01/28/10)



FLAME SCANNER COOLING AIR BLOWER SKID

REV	DESCRIPTION	DATE	APPROVAL

NOTES:

1. FOR PROCESS & INSTRUMENTATION DIAGRAM – DRAWING INDEX, SEE B&W DRAWING B0233970.
2. FOR PROCESS & INSTRUMENTATION DIAGRAM – IDENTIFICATION & TAGGING, SEE B&W DRAWING B0233971.
3. FOR PROCESS & INSTRUMENTATION DIAGRAM – SYMBOLS & NOMENCLATURE, SEE B&W DRAWING B0233972.

AEP KENTUCKY POWER COMPANY
BIG SANDY UNIT 1
LOUISA, KY
NATURAL GAS CONVERSION

User Defined Field 591-0999	DWN JW HEVENER
DRG. CONTRACT NO. 334-0364	CHK'D AK ROSS
– DO NOT SCALE – USE DIMENSIONS ONLY	APP'D JE BOLLINGER
	DATE 9.17.12
	SCALE NONE
	Type: PROJECT
	Dist.Cust.: YES
	Dist.Erec.: NO
	Dist.MFG.: NO

Babcock & Wilcox Power Generation Group, Inc.
20 SOUTH VAN BUREN AVENUE, BARBERTON OHIO

PROCESS & INSTRUMENTATION DIAGRAM
SCANNER COOLING AIR BLOWERS

PROJECT NO.	COA	DWG. NO.		REV.
0635-275R	A00000	B0233976	E	00

(01/28/10)

Risk Analysis Model

Big Sandy Unit 1 Refuel

Phase 0 Cost Estimate - Minus Gas Supply Line

Frozen Estimate

Subtotal of Estimate not Modeled	$ 24,390,658	62%

Range Estimate Risks (> $200k Impact)

Risk Analysis Item	Title	Description	Estimate Range Items: Estimated Value	Probabilty that actual will NOT exceed estimate	Probabilty that actual WILL exceed estimate	Maximum Possible Value (P99)	Minimum Possible Value (P1)	Expected Cost
1	Labor Availability/Quality	Future work schedule will impact the availability of skilled craft labor.	$ 837,000	70%	30%	$ 1,430,641.95	$ 715,321	$ 867,972
3.1	Escalation of OEM Scope	Escalation of OEM construction scope over the estimate amount.	$ 697,066	60%	40%	$ 934,067.82	$ 348,533	$ 658,959
3.2	Escalation of OEM Scope	Escalation of OEM material scope over the estimated amount.	$ 984,595	60%	40%	$ 1,319,357	$ 492,297.32	$ 930,770
4	Equipment Rental	Crane rental estimate exceeded.	$ 1,110,655	60%	40%	$ 1,554,918	$ 500,000	$ 1,047,759
6	Lead & Asbestos Abetment	Lead & asbestos abatement estimate exceeded.	$ 1,406,140	70%	30%	$ 2,000,000	$ 1,000,000	$ 1,370,760
10	Burner Upgrades	Limited access to burner areas increasing costs.	$ 3,424,500	70%	30%	$ 4,451,850	$ 2,397,150	$ 3,287,520
13	Pressure part upgrades - Labor	Pressure part upgrade labor estimate exceeded.	$ 5,135,387	75%	25%	$ 5,750,000	$ 4,500,000	$ 5,027,758
22	Unit 2 Closure	Additional issues and costs related to the closure of Unit 2.	$ 1,440,000	75%	25%	$ 2,000,000	$ 1,000,000	$ 1,376,667
		Range Estimate Risks -Total	$ 15,035,342			$ 19,440,834	$ 10,953,301	$ 14,568,165

Risk Events

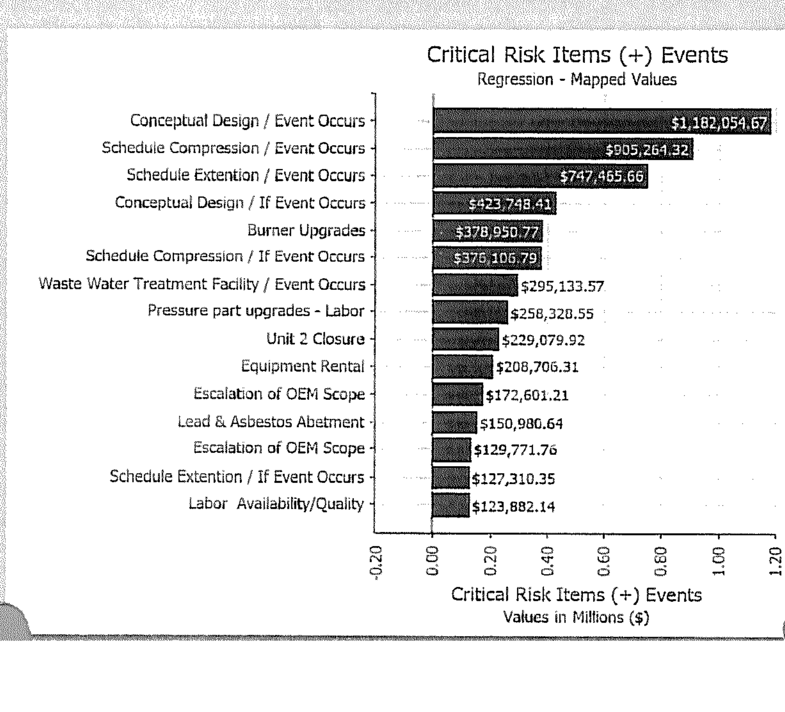
Risk Analysis Item	Title	Description	Risk Events (Variable Probability of Occurrence): Estimated Value	Probability of Occurrence Per Event Opportunity	Number of Event Opportunities Per Project	Maximum Possible Value (P99)	Minimum Possible Value (P1)	Total Impact (sampled) ($k)
A	Schedule Compression	Construction start date is delayed and work must be accelerated.	$ 100,000	15%	2	$ 5,500,000	$ 25,000	$ 562,500
B	Schedule Extention	Unable to start up unit on time due to project related delays.	$ 1,000,000	15%	2	$ 3,000,000	$ 500,000	$ 450,000
G	Waste Water Treatment Facility	Project may need to construct additional waste water treatment facilities.	$ 500,000	10%	1	$ 2,000,000	$ 200,000	$ 90,000
H	Conceptual Design	Detailed engineering design reveals additional scope items or cost savings opportunities.	$ 1,670,000	35%	2	$ 3,340,000	$ 300,000	$ 1,239,000
		Risk Events -Total						$ 2,341,500

Totals

Frozen Estimate - Non-Critical Risk Items	$ 24,390,658
Critical Estimate - Risk Items (Non Events)	$ 15,035,342
Subtotal - Base Estimate w/o Contingency	$ 39,426,000
Contingency required @ P100	$ 9,915,342
P100 Estimate Cost (Does not include Actual Costs)	$ 49,341,342

TOTAL Expected Cost (50/50)	$ 41,300,323

Analysis Summary Results



Percentile	Percentile value	Contingency Req'd	% of Base Est
0%	37,301,186	(2,124,814)	-5.39%
5%	38,567,599	(858,401)	-2.18%
10%	38,852,317	(573,683)	-1.46%
15%	39,145,786	(280,214)	-0.71%
20%	39,509,578	83,578	0.21%
25%	39,795,952	369,952	0.94%
30%	40,031,869	605,869	1.54%
35%	40,286,442	860,442	2.18%
40%	40,598,809	1,172,809	2.97%
45%	40,812,807	1,386,807	3.52%
50%	41,004,972	1,578,972	4.00%
55%	41,222,948	1,796,948	4.56%
60%	41,466,136	2,040,136	5.17%
65%	41,743,553	2,317,553	5.88%
70%	42,039,757	2,613,757	6.63%
75%	42,513,293	3,087,293	7.83%
80%	42,820,079	3,394,079	8.61%
85%	43,311,878	3,885,878	9.86%
90%	43,825,717	4,399,717	11.16%
95%	45,001,556	5,575,556	14.14%
100%	49,341,342	9,915,342	25.15%

A — FUEL AS FIRED

ANALYSES	BY:			
ASTM — TYPE				
ASTM — CLASS				
ASTM — GROUP				
AREA — MINE				
AREA — STATE/PROVINCE				
AREA — COUNTRY				
FUSION TEMPS - F — REDUCING ID				
FUSION TEMPS - F — REDUCING H=1/2W				
FUSION TEMPS - F — REDUCING FLUID				
FUSION TEMPS - F — OXIDIZING ID				
FUSION TEMPS - F — OXIDIZING H=1/2W				
FUSION TEMPS - F — OXIDIZING FLUID				
MISC. — SIZE				
MISC. — GRINDABILITY				
MISC. — SURFACE H2O, %				
PROXIMATE ANALYSIS - % — TOTAL MOISTURE	6.00			
PROXIMATE ANALYSIS - % — VOLATILE MATTER	32.00			
PROXIMATE ANALYSIS - % — FIXED CARBON	48.00			
PROXIMATE ANALYSIS - % — ASH	14.00			
PROXIMATE ANALYSIS - % — TOTAL	100.00			

ULTIMATE ANALYSIS				
FUEL	COAL	Nat Gas		
% BY	WT	VOL		
ASH	9.57			
H2O	8.44			
C	65.36			
H2	4.70			
N2	1.16	1.13		
S	3.41			
O2	7.36			
CH4		76.69		
C2H4				
C2H6		16.54		
C3H8		4.33		
C4H10		0.94		
C5H12		0.20		
C6H14		0.09		
CO				
CO2		0.08		
SO2				
Cl + F	0.00			
TOTAL	100.00	100.00		
HHV, BTU/LB	12,034	22,518		
HHV, BTU/CUFT AT 60F, 30 IN HG		1205		

NOTES:

BY: DATE :

The Babcock & Wilcox Company

275R

B — PREDICTED PERFORMANCE (1)

	LOAD CONDITION	ORIG MCR	FULL	FULL	CONTROL	CONTROL	CONTROL	
								1
	LOAD CONDITION	ORIG MCR	FULL	FULL	CONTROL	CONTROL	CONTROL	2
	STEAM LEAVING SH, MLB/HR	1890.00	2080.00	2080.00	1260.00	1260.00	1260.00	3
	STEAM LEAVING RH1, MLB/HR	1534.00	1700.00	1700.00	1046.00	1046.00	1046.00	4
	STEAM LEAVING RH2, MLB/HR	-	-	-	-	-	-	5
	TYPE OF FUEL	COAL	GAS DIRTY	GAS CLEAN	COAL	GAS DIRTY	GAS CLEAN	6
	EXCESS AIR LEAVING ECONOMIZER, %	18.0	10.0	10.0	20.0	15.5	15.5	7
	NO. OF BURNERS IN OPERATION	18	18	18	18	18	18	8
	OUTPUT PER PTC 4-1998, MKB/HR	-	2400.90	2397.30	-	1509.10	1502.50	9
	HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)	2523.00	2838.00	2803.00	1795.00	1773.00	1747.00	10
	HEAT CREDITS, MKB/HR (PER PTC 4-1998)	0.00	0.00	0.00	0.00	0.00	0.00	11
	FUEL INPUT, MKB/HR	2410.00	2818.10	2802.50	1722.00	1775.10	1761.40	12
QUANTITY - MLB/HR	FUEL FLOW (MCF/HR IF GAS)	200.80	2338.60	2325.80	143.10	1473.10	1461.70	13
QUANTITY - MLB/HR	FLUE GAS ENTERING AIR HEATER	2330.00	2418.10	2404.80	1682.00	1595.40	1583.10	14
QUANTITY - MLB/HR	TOTAL AIR TO BURNING EQUIPMENT	1889.00	2251.30	2238.90	1300.00	1490.30	1478.80	15
QUANTITY - MLB/HR	SECONDARY AIR LEAVING AH	-	-	-	-	-	-	16
QUANTITY - MLB/HR	PRIMARY AIR LEAVING AH	-	-	-	-	-	-	17
QUANTITY - MLB/HR	TEMPERING AIR	-	-	-	-	-	-	18
QUANTITY - MLB/HR	AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-	-	-	-	-	19
QUANTITY - MLB/HR	AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-	-	-	-	-	20
QUANTITY - MLB/HR	AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-	-	-	-	-	21
QUANTITY - MLB/HR	AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-	-	-	-	-	22
QUANTITY - MLB/HR	SUPERHEAT SPRAY FLOW	40.30	219.40	276.00	11.50	99.90	138.70	23
QUANTITY - MLB/HR	REHEAT SPRAY FLOW (RH1/RH2)	0/0	12.3/0	9.4/0	0/0	0/0	0/0	24
PRESSURE - PSIG	STEAM AT SH OUTLET	2500	2500	2500	2500	2500	2500	25
PRESSURE - PSIG	STEAM AT RH1 INLET	535	531	531	357	357	357	26
PRESSURE - PSIG	STEAM AT RH2 INLET	-	-	-	-	-	-	27
PRESSURE - PSIG — DROP	REHEATER 1	25	39	39	16	16	16	28
PRESSURE - PSIG — DROP	REHEATER 2	-	-	-	-	-	-	29
PRESSURE - PSIG — DROP	ECONOMIZER (PLUS FURNACE IF UP)	25	30	30	11	11	11	30
PRESSURE - PSIG — DROP	DRUM OR VSS TO SH OUTLET	150	182	182	67	67	67	31
TEMPERATURE - DEG. F — STEAM	LEAVING SUPERHEATER	1050	1050	1050	1050	1050	1050	32
TEMPERATURE - DEG. F — STEAM	LEAVING REHEATER 1	1050	1050	1050	1050	990	978	33
TEMPERATURE - DEG. F — STEAM	ENTERING REHEATER 1	675	658	661	600	601	601	34
TEMPERATURE - DEG. F — STEAM	LEAVING REHEATER 2	-	-	-	-	-	-	35
TEMPERATURE - DEG. F — STEAM	ENTERING REHEATER 2	-	-	-	-	-	-	36
TEMPERATURE - DEG. F — WATER	ENTERING ECONOMIZER	526	523	523	481	481	481	37
TEMPERATURE - DEG. F — GAS (MHVT)	LEAVING ECONOMIZER	702	711	668	662	658	621	38
TEMPERATURE - DEG. F — GAS (MHVT)	LEAVING AH (EXCL. LKG)	300	314	299	290	289	277	39
TEMPERATURE - DEG. F — GAS (MHVT)	LEAVING AH (INCL. LKG)	-	-	-	-	-	-	40
TEMPERATURE - DEG. F — GAS (MHVT)	ENTERING SSH INLET (24" SPACING)	-	-	-	-	-	-	41
TEMPERATURE - DEG. F — GAS (MHVT)	ENTERING 12" OR LOWER SPACING	-	-	-	-	-	-	42
TEMPERATURE - DEG. F — AIR	ENTERING PRI. AIR HEATER (1)	-	-	-	-	-	-	43
TEMPERATURE - DEG. F — AIR	ENTERING SEC. AIR HEATER (1)	-	-	-	-	-	-	44
TEMPERATURE - DEG. F — AIR	LEAVING AIR HEATER (SEC)	-	-	-	-	-	-	45
TEMPERATURE - DEG. F — AIR	LEAVING AIR HEATER (PRI)	-	-	-	-	-	-	46
TEMPERATURE - DEG. F — FUEL	TO BURNING EQUIPMENT	-	-	-	-	-	-	47
RESISTANCE - IN. H2O — GAS	FURNACE & CONVECTION BANKS	-	-	-	-	-	-	48
RESISTANCE - IN. H2O — GAS	FLUES TO AH OUTLET	-	-	-	-	-	-	49
RESISTANCE - IN. H2O — GAS	AIR HEATER	-	-	-	-	-	-	50
RESISTANCE - IN. H2O — GAS	SCR	-	-	-	-	-	-	51
RESISTANCE - IN. H2O — GAS	TOTAL FROM FURNACE TO STACK	-	-	-	-	-	-	52
RESISTANCE - IN. H2O — PRI AIR	AIR HEATER	-	-	-	-	-	-	53
RESISTANCE - IN. H2O — PRI AIR	DUCTS & FLOW METER	-	-	-	-	-	-	54
RESISTANCE - IN. H2O — PRI AIR	PULVERIZERS	-	-	-	-	-	-	55
RESISTANCE - IN. H2O — PRI AIR	FUEL PIPING TO BURNERS	-	-	-	-	-	-	56
RESISTANCE - IN. H2O — PRI AIR	BURNERS	-	-	-	-	-	-	57
RESISTANCE - IN. H2O — PRI AIR	TOTAL	-	-	-	-	-	-	58
RESISTANCE - IN. H2O — SEC AIR	FUEL BURNERS & WINDBOX	-	-	-	-	-	-	59
RESISTANCE - IN. H2O — SEC AIR	DUCTS & FLOW METER	-	-	-	-	-	-	60
RESISTANCE - IN. H2O — SEC AIR	AIR HEATER	-	-	-	-	-	-	61
RESISTANCE - IN. H2O — SEC AIR	TOTAL FROM FD FAN TO FURNACE	-	-	-	-	-	-	62
HEAT LOSSES, %	DRY GAS	3.980	3.220	2.950	3.800	3.240	3.010	63
HEAT LOSSES, %	H2 & H2O IN FUEL	4.370	9.810	9.740	4.340	9.860	9.810	64
HEAT LOSSES, %	MOISTURE IN AIR	0.100	0.080	0.080	0.100	0.080	0.080	65
HEAT LOSSES, %	UNBURNED COMBUSTIBLE IN RESIDUE	0.480	0.000	0.000	0.600	0.000	0.000	66
HEAT LOSSES, %	RADIATION	0.160	0.190	0.190	0.240	0.300	0.300	67
HEAT LOSSES, %	SENSIBLE HEAT IN REFUSE	0.000	0.000	0.000	0.000	0.000	0.000	68
HEAT LOSSES, %	MANUFACTURER'S MARGIN	1.500	1.500	1.500	1.500	1.500	1.500	69
HEAT LOSSES, %	OTHER LOSSES (UNMEASURED)	0.000	0.000	0.000	0.000	0.000	0.000	70
	TOTAL LOSSES	10.590	14.800	14.460	10.580	14.980	14.700	71
HEAT CREDITS, %	ENTERING DRY AIR	0.000	0.000	0.000	0.000	0.000	0.000	72
HEAT CREDITS, %	MOISTURE IN AIR	0.000	0.000	0.000	0.000	0.000	0.000	73
HEAT CREDITS, %	SENSIBLE HEAT IN FUEL	0.000	0.000	0.000	0.000	0.000	0.000	74
HEAT CREDITS, %	AUXILIARY EQUIPMENT POWER	0.000	0.000	0.000	0.000	0.000	0.000	75
HEAT CREDITS, %	OTHER CREDITS (UNMEASURED)	0.000	0.000	0.000	0.000	0.000	0.000	76
	TOTAL CREDITS	0.000	0.000	0.000	0.000	0.000	0.000	77
	ASME PTC 4-1998 FUEL EFFICIENCY, %	89.410	85.200	85.540	89.420	85.020	85.300	78
PULV. & FEEDER	NO. IN USE PER BOILER	6	-	-	6	-	-	79
PULV. & FEEDER	% THRU 200 U.S.S. SIEVE	70.0	-	-	70.0	-	-	80

ENG | PREDICTED PERFORMANCE IS BASED ON CONDITIONS AND EQUIPMENT SHOWN ON THIS SUMMARY SHEET AND ON GENERAL ARRANGEMENT DRAWING(S)
POUNDS WATER PER POUND COMBUSTION AIR = 0.0130 AND BAROMETRIC PRESSURE = 29.92 IN HG

C — EQUIPMENT PER UNIT

TYPE RB-364	
SIZE	
DRUM DESIGN PRESSURE (MASTER STAMPING IF UP), PSIG	2800
PRESSURE PART HEATING SURFACE — FURN — WATER COOLED SCREEN (CIRCUM.)	
FURN — WATER COOLED (PROJECTED)	
FURN — SUPERHEATER (CIRCUMFERENTIAL)	
FURN — SUPERHEATER (PROJECTED)	
TOTAL FURNACE HEATING SURFACE	
CONV — SATURATED (CIRCUMFERENTIAL)	
CONV — SUPERHEATER (CIRCUMFERENTIAL)	
CONV — ECONOMIZER	
TOTAL CONVECTION HEATING SURFACE	
TOTAL FURN & CONV PRESSURE PART HTG SURF	
FLAT PROJECTED FURNACE HEATING SURFACE:	
TO FACE OF SH (24" CL)	
SQ FT — TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CUBIC FEET	
AIR HEATER — TYPE REGENERATIVE	QUANTITY:
AIR HEATER — TOTAL HEATING SURFACE, SQUARE FEET:	
FUEL BURNER — TYPE:	XCL-S PROPOSED
FUEL BURNER — NO.:	18
PULV — TYPE:	
PULV — SIZE:	
PULV — NUMBER	
STEAM TEMP. CONTROL	SH & RH ATTEMPERATION
STEAM TEMP. CONTROL	EXCESS AIR
UNIT CONSTR. FEATURES	PARALLEL PASS HORIZONTAL CONVECTION SURF

REVISIONS

NO.	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sandy Unit 1
Natural Gas Conversion
Existing Surface

Exhibit RLW-2, Appendix A

A — FUEL AS FIRED

	ANALYSES	BY:			
ASTM	TYPE				
	CLASS				
	GROUP				
AREA	MINE				
	STATE/PROVINCE				
	COUNTRY				
FUSION TEMPS - F	REDUCING ID				
	REDUCING H=1/2W				
	REDUCING FLUID				
	OXIDIZING ID				
	OXIDIZING H=1/2W				
	OXIDIZING FLUID				
MISC.	SIZE				
	GRINDABILITY				
	SURFACE H_2O, %				
PROXIMATE ANALYSIS - %	TOTAL MOISTURE	6.00			
	VOLATILE MATTER	32.00			
	FIXED CARBON	48.00			
	ASH	14.00			
	TOTAL	100.00			
ULTIMATE ANALYSIS	FUEL	COAL	Nat Gas		
	% BY	WT	VOL		
	ASH	9.57			
	H_2O	8.44			
	C	65.36			
	H_2	4.70			
	N_2	1.16	1.13		
	S	3.41			
	O_2	7.36			
	CH_4		76.69		
	C_2H_4				
	C_2H_6		16.54		
	C_3H_8		4.33		
	C_4H_{10}		0.94		
	C_5H_{12}		0.20		
	C_6H_{14}		0.09		
	CO				
	CO_2		0.08		
	SO_2				
	Cl + F	0.00			
	TOTAL	100.00	100.00		
	HHV, BTU/LB	12,034	22,518		
	HHV, BTU/CUFT AT 60F, 30 IN HG		1205		

NOTES:

BY: DATE:

The Babcock & Wilcox Company

275R

B — PREDICTED PERFORMANCE (1)

No.				
2		LOAD CONDITION	Minimum Load	Minimum Load
3		STEAM LEAVING SH, MLB/HR	780.00	780.00
4		STEAM LEAVING RH1, MLB/HR	630.00	630.00
5		STEAM LEAVING RH2, MLB/HR	-	-
6		TYPE OF FUEL	GAS DIRTY	GAS CLEAN
7		EXCESS AIR LEAVING ECONOMIZER, %	22.0	22.0
8		NO. OF BURNERS IN OPERATION	18	18
9		OUTPUT PER PTC 4-1998, MKB/HR	976.10	968.50
10		HEAT AVAILABLE, MKB/HR (FUEL & HEATED AIR)	1141.00	1121.00
11		HEAT CREDITS, MKB/HR (PER PTC 4-1998)	0.00	0.00
12		FUEL INPUT, MKB/HR	1146.00	1133.10
13	QUANTITY - MLB/HR	FUEL FLOW (MCF/HR IF GAS)	951.00	940.40
14		FLUE GAS ENTERING AIR HEATER	1085.00	2475.13
15		TOTAL AIR TO BURNING EQUIPMENT	1017.20	1005.80
16		SECONDARY AIR LEAVING AH	-	-
17		PRIMARY AIR LEAVING AH	-	-
18		TEMPERING AIR	-	-
19		AIR HTR LEAKAGE (TOTAL AIR TO GAS)	-	-
20		AIR HTR LEAKAGE (PRI AIR TO GAS)	-	-
21		AIR HTR LEAKAGE (SEC AIR TO GAS)	-	-
22		AIR HTR LEAKAGE (PRI AIR TO SEC AIR)	-	-
23		SUPERHEAT SPRAY FLOW	36.62	56.73
24		REHEAT SPRAY FLOW (RH1/RH2)	0/0	0/0
25	PRESSURE - PSIG	STEAM AT SH OUTLET	2500	2500
26		STEAM AT RH1 INLET	220	220
27		STEAM AT RH2 INLET	-	-
28	DROP	REHEATER 1	8	8
29		REHEATER 2	-	-
30		ECONOMIZER (PLUS FURNACE IF UP)	4	4
31		DRUM OR VSS TO SH OUTLET	26	26
32	TEMPERATURE - DEG. F — STEAM	LEAVING SUPERHEATER	1050	1050
33		LEAVING REHEATER 1	951	928
34		ENTERING REHEATER 1	553	553
35		LEAVING REHEATER 2	-	-
36		ENTERING REHEATER 2	-	-
37	WATER	ENTERING ECONOMIZER	427	427
38	GAS (MHVT)	LEAVING ECONOMIZER	611	576
39		LEAVING AH (EXCL. LKG)	268	256
40		LEAVING AH (INCL. LKG)	-	-
41		ENTERING SSH INLET (24" SPACING)	-	-
42		ENTERING 12" OR LOWER SPACING	-	-
43	AIR	ENTERING PRI. AIR HEATER (1)	-	-
44		ENTERING SEC AIR HEATER (1)	-	-
45		LEAVING AIR HEATER (SEC)	-	-
46		LEAVING AIR HEATER (PRI)	-	-
47	FUEL	TO BURNING EQUIPMENT	-	-
48	RESISTANCE - IN. H_2O — GAS	FURNACE & CONVECTION BANKS	-	-
49		FLUES TO AH OUTLET	-	-
50		AIR HEATER	-	-
51		SCR	-	-
52		TOTAL FROM FURNACE TO STACK	-	-
53	PRI AIR	AIR HEATER	-	-
54		DUCTS & FLOW METER	-	-
55		PULVERIZERS	-	-
56		FUEL PIPING TO BURNERS	-	-
57		BURNERS	-	-
58		TOTAL	-	-
59	SEC AIR	FUEL BURNERS & WINDBOX	-	-
60		DUCTS & FLOW METER	-	-
61		AIR HEATER	-	-
62		TOTAL FROM FD FAN TO FURNACE	-	-
63	HEAT LOSSES, %	DRY GAS	3.000	2.760
64		H_2 & H_2O IN FUEL	9.770	9.720
65		MOISTURE IN AIR	0.080	0.070
66		UNBURNED COMBUSTIBLE IN RESIDUE	0.000	0.000
67		RADIATION	0.470	0.470
68		SENSIBLE HEAT IN REFUSE	0.000	0.000
69		MANUFACTURER'S MARGIN	1.500	1.500
70		OTHER LOSSES (UNMEASURED)	0.000	0.000
71		TOTAL LOSSES	14.820	14.520
72	HEAT CREDITS, %	ENTERING DRY AIR	0.000	0.000
73		MOISTURE IN AIR	0.000	0.000
74		SENSIBLE HEAT IN FUEL	0.000	0.000
75		AUXILIARY EQUIPMENT POWER	0.000	0.000
76		OTHER CREDITS (UNMEASURED)	0.000	0.000
77		TOTAL CREDITS	0.000	0.000
78		ASME PTC 4-1998 FUEL EFFICIENCY, %	85.180	85.480
79	PULV & FEEDER	NO. IN USE PER BOILER	-	-
80		% THRU 200 U.S.S. SIEVE	-	-

ENG

81 PREDICTED PERFORMANCE IS BASED ON CONDITIONS AND EQUIPMENT SHOWN ON THIS SUMMARY SHEET AND ON GENERAL ARRANGEMENT DRAWING(S)
82 POUNDS WATER PER POUND COMBUSTION AIR = 0.0130 AND BAROMETRIC PRESSURE = 29.92 IN HG

C — EQUIPMENT PER UNIT

	TYPE RB-364		
	SIZE		
	DRUM DESIGN PRESSURE (MASTER STAMPING IF UP), PSIG		2800
PRESSURE PART HEATING SURFACE — FURN	WATER COOLED SCREEN (CIRCUM.)		
	WATER COOLED (PROJECTED)		
	SUPERHEATER (CIRCUMFERENTIAL)		
	SUPERHEATER (PROJECTED)		
	TOTAL FURNACE HEATING SURFACE		
CONV	SATURATED (CIRCUMFERENTIAL)		
	SUPERHEATER (CIRCUMFERENTIAL)		
	ECONOMIZER		
	TOTAL CONVECTION HEATING SURFACE		
	TOTAL FURN & CONV PRESSURE PART HTG SURF		
	FLAT PROJECTED FURNACE HEATING SURFACE:		
SQ FT	TO FACE OF SH (24" CL)		
	TO FACE OF CONVECTION SURFACE		
	FURNACE VOLUME, CUBIC FEET		
AIR HEATER	TYPE: REGENERATIVE	QUANTITY:	
	TOTAL HEATING SURFACE, SQUARE FEET:		
FUEL BURNER	TYPE:	XCL-S PROPOSED	
	NO.:	18	
PULV	TYPE:		
	SIZE:		
	NUMBER:		
STEAM TEMP. CONTROL	SH & RH ATTEMPERATION		
	EXCESS AIR		
UNIT CONSTR. FEATURES	PARALLEL PASS HORIZONTAL CONVECTION SURF		

REVISIONS

NO.	DATE	BY	DESCRIPTION

CUSTOMER:

B&W 275R AEP Big Sandy Unit 1
Natural Gas Conversion
Existing Surface

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

The Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing Kentucky Power To Convert The Existing Big Sandy Unit 1 To Be Exclusively Fueled By Natural Gas (2) For Declaratory Rulings; And (3) For All Other Required Approvals And Relief	))) Case No. 2013-)

DIRECT TESTIMONY

OF

SCOTT C. WEAVER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Scott C. Weaver being duly sworn, deposes and says he is the Managing Director Resource Planning and Operation Analysis for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

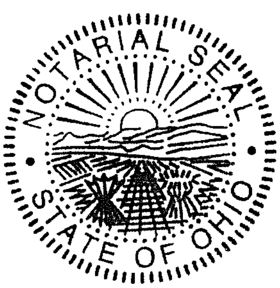
SCOTT C. WEAVER

STATE OF OHIO)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 4th day of December 2013.

Notary Public

My Commission Expires: May 16th, 2016



ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

DIRECT TESTIMONY OF
SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-

TABLE OF CONTENTS

DIRECT TESTIMONY OF SCOTT C. WEAVER, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the eleven electric operating companies of the American Electric Power System ("AEP").

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed the AEP Management Development Program at The Ohio State University; as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controller's Department (now Corporate Planning and Budgeting Department), and was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in

1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January, 2003 transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR– RESOURCE PLANNING AND OPERATIONAL ANALYSIS?**

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for Kentucky Power Company ("Kentucky Power", or "the Company") and its parent, AEP, regularly monitor actual performance, and review the preparation of forecasted information for use in regulatory proceedings.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?**

A. Yes. I recently offered testimony in the Company's filing seeking a certificate of public convenience and necessity ("CPCN") authorizing the transfer to Kentucky Power of a 50 percent undivided interest in the Mitchell Generating Station (Case No. 2012-00578). I have offered testimony in Kentucky Power's filing for a CPCN for the construction of environmental controls at its Big Sandy Unit 2 (Case No. 2011-

00401). I have also offered testimony before this Commission on behalf of the Company's prior base rate case (Case No. 2009-00459); as well as its renewable energy purchase agreement filing for wind resources (Case No. 2009-00545). I was responsible for the development of Kentucky Power's 2009 Integrated Resource Plan filing (Case No. 2009-00339). In addition, over the last six years I have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Indiana, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purposes of my testimony are to:

1) discuss the available disposition options related to Kentucky Power's 278 MW Big Sandy Unit 1 coal-fired generating unit, the need for which is being driven by known and emerging environmental regulations and legal requirements beginning in the nearer-term and continuing through this decade;

2) briefly describe the modeling process used to evaluate the relative economics of the available Big Sandy Unit 1 disposition options, including a discussion of the Request for Proposal ("RFP") for 250 MW of long-term capacity and energy that would be intended to replace the unit; and

3) discuss the results of these economic modeling analyses which indicate that the optimal solution for Kentucky Power would be to convert the Big Sandy Unit 1 steam generator/boiler to exclusively burn natural gas by June 2016.

Q. WERE YOUR EXHIBITS USED TO SUPPORT YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes they were. As I will describe in this testimony, it is important to realize, however, that numerous management and functional groups within Kentucky Power and AEPSC were involved in this process. The role I served was one of coordinating the attendant economic modeling effort and, ultimately, validating, documenting, and internally communicating this process and the results.

IV. AVAILABLE ALTERNATIVES

Q. WHAT ARE THE ALTERNATIVES REASONABLY AVAILABLE TO KENTUCKY POWER TO ADDRESS THESE IMPENDING ENVIRONMENTAL REQUIREMENTS AT BIG SANDY UNIT 1?

A. As summarized on the following TABLE 1, two alternative options were assumed to be available to Kentucky Power to address the unit disposition decisions facing Big Sandy Unit 1:

TABLE 1

Option #1: Convert Big Sandy Unit 1 to a Natural Gas-Steam Unit
Convert Big Sandy Unit 1 to exclusively burn natural gas by July 2015.
("Option #5A" from Case No. 2012-00578)

Option #2: Retire & Replace Big Sandy Unit 1
Option #2A... Replace Big Sandy Unit 1 with market purchases of capacity and energy effective June 2015; with such purchases assumed to be from the (forecasted) PJM market for a period of 10 years, then assume new-build natural gas combined cycle ("CC"), or natural gas combustion turbine ("CT") units.
("Option #6" from Case No. 2012-00578)

Option #2B... Replace Big Sandy Unit 1 with bilaterally-purchased capacity and energy effective June 2015; with such purchases emanating from a 250 MW RFP issued by the Company on March 28, 2013.

Q. OVERALL, HOW DO THE BIG SANDY UNIT 1 ALTERNATIVE DISPOSITION OPTIONS COMPARE TO THOSE EVALUATED AS PART OF CASE NO. 2012-00578?

A. Each of these alternatives was effectively evaluated as part of the analysis performed as part of Case No. 2012-00578. Specifically, Option #1 is based on the Big Sandy 1 alternative reflected as part of "Option #5A", from Case No. 2012-00578. Option #2A is based on the Big Sandy 1 alternative reflected as part of "Option #6" from Case No. 2012-00578.[1] Finally, Option #2B is predicated upon the results of the Kentucky Power RFP evaluation for 250 MW of capacity and energy discussed in Case No. 2012-00578.[2]

Q. BOTH CASE NOS. 2011-00401 AND 2012-00578 INCORPORATED AN ADDITIONAL DISPOSITION OPTION FOR BIG SANDY UNIT 1 INVOLVING "REPOWERING" THE UNIT AS A COMBINED CYCLE UNIT. WHY WAS THAT OPTION NOT CONSIDERED HERE?

A. It was not considered primarily due to the fact that Kentucky Power would not require the amount of capacity that would be offered by such a CC-repowered Unit 1 now that the Commission has approved the transfer to the Company of an undivided 50% interest in the Mitchell generating station. A "repowered" Big Sandy Unit 1 would provide 762 MW of nominally-rated generating capacity (918 MW for peaking purposes with duct-firing). In combination with the 780 MW of Mitchell units to be transferred to Kentucky Power effective January, 2014, the Company would far exceed its capacity need with such a CC-repowered unit. Further, recall that such a CC-repowered Big Sandy Unit 1 option was considered in those prior applications in

[1] *See* S.C. Weaver direct testimony "TABLE 1" and Exhibit SCW-2 from Case No. 2012-00578.
[2] *See* Weaver supplemental testimony Exhibit SCW-1S from Case No. 2012-00578.

lieu of a *Big Sandy Unit 2* alternative; be it the Mitchell Transfer option (Case No. 2012-00578) or a Big Sandy Unit 2 flue gas desulfurization ("FGD") retrofit (both Case Nos. 2011-00401 and 2012-00578). In each of those filings, a Big Sandy Unit 1 "CC-repowered" option was one of the more costly alternatives.

V. PLANNING PROCESS AND IMPENDING ENVIRONMENTAL REQUIREMENTS

Q. PLEASE DESCRIBE THE IMPLICATIONS OF KNOWN ENVIRONMENTAL REGULATIONS ON KENTUCKY POWER'S RESOURCE PLANNING PROCESS FOR BIG SANDY UNIT 1.

A. The most significant environmental regulation impacting Big Sandy Unit 1 is the U.S. Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS") Rule. As further discussed in the testimony of Company Witnesses Wohnhas and Walton, the MATS Rule effectively precludes Big Sandy 1 from operating as a coal-fired unit beyond April 2015,[3] unless significant environmental retrofits in the form of costly FGD and selective catalytic reduction ("SCR") technology were installed.[4] Given the age[5] and, more importantly, the smaller-size of Big Sandy Unit 1, the relative economies of such a large environmental investment on Unit 1 lacked sufficient scale to merit consideration. In addition, the alternative evaluations performed around the larger, newer Big Sandy Unit 2 as part of Case No.

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[3] Although the MATS Rule implementation date is April (16), 2015, it is expected, after consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of MATS, that the AEP-East units—including Big Sandy Unit 2—being planned for retirement will be able to operate through the full PJM 2014/15 capacity "planning year" (*i.e.*, through May 31, 2015). Additionally, as discussed in the testimony of Company Witnesses Wohnhas and Walton, Kentucky Power will seek authorization from the Kentucky Division for Air Quality, consistent with the MATS Rule, to continue operating Big Sandy Unit 1 as a coal-fired unit until April 15, 2016, while the natural gas conversion project is completed.

[4] Co-benefits of combined FGD and SCR technology retrofitting would include mercury control, a specific requirement of the MATS Rule.

[5] Unit 1 was placed in service in 1963.

2012-00578, demonstrated that the economics were not favorable. This confirmed that retrofitting Big Sandy Unit 1 as a coal-fired unit to achieve MATS Rule requirements was simply not a reasonable or least-cost solution.

Q. **DOES THE NEW SOURCE REVIEW CONSENT DECREE LIMIT IN ANY WAY THE OPTION #1 (GAS CONVERSION) ALTERNATIVE FOR BIG SANDY UNIT 1?**

A. No. The NSR Consent Decree does not establish specific limits on Big Sandy Unit 1 other than it "can only burn coal with a sulfur content no greater than 1.75 lb/mmBtu on an annual average basis." The Consent Decree does not preclude the Company from converting that unit to burn natural gas as set forth in Option #1.[6]

VI. ECONOMIC MODELING PROCESS AND RESULTS

Q. **HOW WERE THESE IDENTIFIED ALTERNATIVES ANALYZED?**

A. Similar to the Kentucky Power unit disposition analysis presented in both Case No. 2011-00401 and Case No. 2012-00578, the Company utilized a proprietary long-term resource optimization tool known as Strategist® to identify the relative least-cost alternative among those identified in TABLE 1. Strategist® is a highly sophisticated and industry-wide accepted economic modeling application. To reiterate from those prior cases, the results from Strategist® offer a view of these relative, option-specific economics over the full, nearly 30-year analysis study period and thereby do not constitute an isolated test-year cost-of-service view.

Q. **PLEASE DESCRIBE THE BIG SANDY UNIT 1 GAS CONVERSION ALTERNATIVE NOW BEING REPRESENTED AS OPTION #1 IN THIS FILING.**

[6] It should be noted that, as a gas-fired unit, Big Sandy Unit 1 would emit essentially *zero* sulfur dioxide (SO_2).

A. As further described by Company Witness Walton, this alternative is based on an approach which would allow the existing, 278 MW Big Sandy Unit 1 to burn natural gas in its steam generator/boiler instead of coal. As he indicates, it would require some boiler and burner modifications and would require the necessary gas pipeline infrastructure. Recognizing, however, that the unit would be expected to operate at a slightly higher heat rate than it had as a coal unit, the converted Big Sandy Unit 1 would naturally be expected to economically-generate less energy (*i.e.*, operate at a lower capacity factor) as a gas-fired facility, than when previously operating as a coal-fired unit due to the relative higher projected $/MMBtu price of natural gas versus coal. Despite this, the attendant potential cyclic, start-and-stop nature of its operation would better lend itself to a more robust sub-critical steam generator/boiler design of Big Sandy Unit 1 (as opposed to a larger, super-critical unit such as Big Sandy Unit 2).

Moreover, as a gas-fired unit, Unit 1 would emit roughly one-half of the relative carbon dioxide ("CO_2")—on a "per Mwh generated" basis—as it did as a coal-fired unit lending to additional attributable benefits.

Q. WHAT IS THE ESTIMATED CAPITAL COST OF OPTION #1 – THE PROPOSED BIG SANDY UNIT 1 GAS CONVERSION?

A. As also described by Company Witness Walton, the estimated capital cost of Option #1 is approximately $50 million, before AFUDC, and excluding the cost of the required gas pipeline lateral to be built by the natural gas supplier.

Q. FOR "OPTION 2A", HOW WERE THE "PJM MARKET" PRICES FOR ENERGY AND CAPACITY DETERMINED FOR MODELING PURPOSES?

A. The Strategist® modeling to proxy, specifically, Option #2A summarized on TABLE 1 was based on the assumption that any and all incremental capacity and energy requirements—*i.e.*, over-and-above what would be received from the 50% of Mitchell Units 1 and 2 to be transferred to Kentucky Power, as well as the Company's purchase share of Rockport Units 1 and 2[7] and the capacity and energy received under the renewable energy purchase agreement for biomass energy with ecoPower Hazard, LLC—would be fully-met via PJM market sourcing for some interim period prior to the eventual addition of CC or simple-cycle CT capacity resources.

The modeling utilized projections of such market values for Unforced Capacity ("UCAP") applicable to the PJM Reliability Pricing Model ("RPM") capacity market construct, as provided by the AEP Fundamental Analysis group. Likewise, the attendant Kentucky Power *energy* requirements that would emerge under this Option #2A alternative were based on the parallel AEP Fundamental Analysis estimates of PJM on-peak and off-peak energy pricing proxied at the AEP Generating hub.

Q. **PLEASE DESCRIBE THE RFP EVALAUATION PROCESS UNDERTAKEN AND THAT SERVES AS THE BASIS FOR "OPTION 2B" IN THIS FILING.**

A. The Company evaluated responses to its RFP issued on March 28, 2013 for up to 250 MW of long-term (15-year) capacity and attendant energy effective June 1, 2015 (the "250 MW RFP"). This solicitation was issued to seek alternatives to converting Big Sandy Unit 1 to burn natural gas instead of coal (which would result in a continued capacity contribution of 268 MW). As discussed by Company Witnesses Wohnhas and Karrasch, pursuant to the Stipulation and Settlement Agreement in Case No.

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[7] Kentucky Power's purchase share of Rockport Units 1 and 2 were assumed to be 15% (approximately 390 MW of the units' combined 2,600 MW) through the modeled long-term study period.

2012-00578, approved by the Commission on October 7, 2013, the Company has exercised its right to terminate the 250 MW RFP. However, the analysis of the bids submitted in response to the 250 MW RFP *remains a valuable benchmark* for the economic analysis of the Big Sandy Unit 1 natural gas conversion project.

Q. WHAT WERE THE RESPONSES TO THE COMPANY'S 250 MW RFP SOLICITATION?

A. Estimated cost and performance profiles associated with the Big Sandy Unit 1 gas conversion option were received for modeling purposes on June 7, 2013. As further described in the direct testimony of Company Witness Karrasch, on June 11, 2013, AEPSC, as agent for Kentucky Power, received a total [redacted] As he further described, the responses to the 250 MW RFP consisted of [redacted]

Q. WOULD YOU BRIEFLY IDENTIFY AND DESCRIBE THE NATURE OF THE CONFORMING OFFERS THAT WERE FURTHER EVALUATED BY THE COMPANY?

[redacted] Yes. Kentucky Power received [redacted] conforming bids consisting of offers from [redacted]

[redacted]

Q. HOW WERE THE COSTS AND PERFORMANCE PARAMETERS OF THE 250 MW RFP BIDS DEVELOPED FOR USE IN THE STRATEGIST® MODELING?

A. The 250 MW RFP bid analysis involved extracting and assembling the pricing and performance characteristics submitted for each conforming proposal, by the respective bidding parties. As Company Witness Karrasch describes, to the extent that issues arose that required clarification from the non-affiliate bidders, requests for additional information were made by the Company's representative to the designated contact person for each of the respective responding companies. This clarification process occurred within the period June 11 through June 21, 2013.

Q. DID THE COMPANY REFRESH THE INFORMATION CONTAINED IN THE CONFORMING PROPOSALS?

A. No. As described above, pursuant to the terms of the approved Stipulation and Settlement Agreement in Case No. 2012-00578, Kentucky Power has exercised its right to terminate the 250 MW RFP. That said, the information obtained in the conforming proposals and the analysis performed continued to provide a valuable, indicative benchmark against which to measure the Big Sandy Unit 1 conversion.

Q. WHAT WERE THE NEXT STEPS IN THE ECONOMIC MODELING PROCESS?

A. Once the required preliminary option-specific input parameters were received and reasonably validated, the disposition options (including the 250 MW RFP-based alternatives) were then introduced as part of Kentucky Power's overall resource portfolio for purposes of executing the Strategist® long-term resource optimization model. (Strategist® being the tool that was also used in the previous Big Sandy 1 and 2 "unit disposition" evaluations I have previously sponsored.) Specifically, each option was viewed on a Kentucky Power "holistic" basis, by being individually and mutually-exclusively substituted into Kentucky Power's resource portfolio *as an alternative to the continued operation of Big Sandy Unit 1 as a coal unit* effective June 1, 2015.[8] With that, the objective function of this evaluation exercise was to—similar to previous Big Sandy 1 and 2 unit disposition evaluation processes—compare the overall Kentucky Power cumulative present worth ("CPW")[9] of costs (revenue requirements) over the 28-year study period (2013-2040) for each of the Options evaluated.

[8] This overall Kentucky Power resource portfolio included for modeling purposes: retirement of Big Sandy Unit 2 effective June 1, 2015; a (50%) Mitchell Plant Unit 1&2 Asset Transfer effective January 1, 2014; the continuation of Kentucky Power's 393 MW purchase agreement for (15%) of Rockport Units 1 and 2 via AEP Generating Company; the 58.5 MW of capacity and attendant energy from the recently approved renewable energy purchase agreement with ecoPower Hazard, LLC; as well as the projected levels of demand-side management.

[9] "CPW" being equivalent to a "net present value" determination.

Q. COULD YOU PLEASE IDENTIFY SOME OF THE MORE CRITICAL INPUT PARAMETERS FOR THE ECONOMIC MODELING PROCESS AND WHERE THAT INFORMATION WAS SOURCED?

A. Two of the major underpinnings in this process are long-term forecasts of Kentucky Power's energy sales and customer (peak) demand, as well as the price of various generation-related commodities, such as energy, capacity, coal, natural gas, and emission allowances, including carbon/CO_2. Both views were created internally within AEPSC. The load forecast was created by the AEP Economic Forecasting organization; while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. These groups have had years of experience forecasting Kentucky Power and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. The long-term load and commodity price forecasts used in this analysis were prepared in the summer of 2013 and represent the most recent versions of each.

Q. DID SUCH GENERIC MODELING ASSUMPTONS FOR THIS 250 MW RFP ANALYSIS CONTINUE TO INCLUDE THE PRESUMPTION OF A "CARBON TAX"?

A. Yes. As with prior cases, a carbon tax effective in the year 2022 is assumed as part of this Big Sandy 1 unit disposition analysis. The Company's modeling *has continued to assume* such a carbon tax—as a reasonable proxy for the deleterious impacts on fossil-fired units of either EPA greenhouse gas ("GHG") regulations, or the possibility of federal legislation around carbon—that would be applicable to each ton of carbon dioxide emitted from all fossil generating sources beginning in the year 2022.[10]

A. BIG SANDY UNIT 1 EVALUATION SUMMARY

Q. WHAT WERE THE RESULTS OF THE BIG SANDY UNIT 1 MODELING ANALYSIS?

A. Exhibit SCW-1 offers a tabular summarization and comparison of the long-term modeling results for the three Kentucky Power disposition options/sub-options for Big Sandy Unit 1 identified on TABLE 1. As also previously described in this testimony these modeling results represent relative cost analyses, meaning they are compared to each other to determine the least-cost alternative outcomes. Given that, Exhibit SCW-1 reflects the relative cost/benefit of the Big Sandy Unit 1 gas conversion (Option #1) versus both a (PJM) market substitution alternative (Option #2A), as well as the results of the Company's 250 MW RFP (Option #2B). It establishes that the optimum Kentucky Power long-term alternative would be one that would include the conversion of Big Sandy Unit 1 as a natural-gas fired steam unit. Option #1 is a least-cost option over the long-term study period analyzed. It is lower than Option #2A by $134 million. Further, it varies from [redacted]

Q. THE MODELING [redacted]

[10] *See* pages 11 and 12 of the direct testimony of Company Witness Bletzacker in Case No. 2012-00578 for a discussion of how the amount and timing of this assumed "carbon tax" was established for such modeling purposes. See also pages 16 and 17 of the supplemental testimony of Company Witness Munczinski and the hearing testimony of Company Witness McManus in Case No. 2012-00578 for a discussion of how the 2022 carbon tax start date comports with the President's recent directive to the EPA regarding regulation of GHG for existing sources.

[redacted]

[redacted] No it is not. As further described later in this testimony, a previous analysis from Case No. 2012-00578 indicated that the Big Sandy Unit 1 gas conversion option was [redacted];[11] but that there were other "qualitative" factors which would provide additional relative value to the Big Sandy Unit 1 gas conversion solution.[12] Under the modeling for this case, the cost of the [redacted]

[redacted]

Q. DOES THE CHANGE IN IN-SERVICE DATE FOR THE BIG SANDY UNIT 1 CONVERSION HAVE ANY MATERIAL IMPACT ON THE ANALYSIS?

A. No. The Strategist® analysis performed for this case continued to assume a June 1, 2015 in-service date for the Big Sandy Unit 1 natural gas conversion. This was done to ensure an "apples to apples" comparison with 250 MW RFP-based market

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[11] *See* supplemental testimony of S.C. Weaver in Case No. 2012-00578; pg. 8.
[12] *ibid*; pgs. 8-9.
[13] $16.8 million / $5,947 million (Option #1 total CPW) = 0.002825

alternatives. To now shift this conversion project in-service date to the anticipated "mid-May 2016" date as described by Company Witness Walton would unfairly bias the relative results of Option #1 *versus* the RFP offers—which had each assumed a June 2015 start date—inasmuch as the Big Sandy Unit 1-related economics would be advantaged by virtue of the prospect of operating for nearly an additional year as a lower-cost, coal-fired unit. Moreover, the additional year of lower cost, coal-fired operation is *only* available under the MATS Rule if Big Sandy Unit 1 is to be converted in this fashion.

Q. WHAT OTHER FACTORS ASSOCIATED WITH THESE MODELING RESULTS SHOULD BE RECOGNIZED?

[redacted] When viewed from an "annual" CPW perspective, the relative CPW differences between the Big Sandy Unit 1 Gas Conversion and [redacted]

Note further on (Confidential) Exhibit SCW-1A that if one were to <u>exclude</u> the value of "ICAP Revenue" (col. B), then the [redacted] In other words, if capacity value from the currently price-volatile PJM-RPM capacity market construct were not considered, [redacted]

Q. WHAT ADDITIONAL ADVANTAGES WOULD THIS CAPACITY AND ENERGY PRESERVATION AT BIG SANDY OFFER KENTUCKY POWER AND ITS CUSTOMERS?

A. It would naturally increase the relative "mix" of natural gas into Kentucky Power's generating portfolio. As described in the testimony of Company Witness Wohnhas, after Big Sandy Unit 1 is converted, that natural gas-sourced capacity mix would equate to nearly 18 percent.[14] With that, it would then offer a physical hedge against the prospect of any lower-than-forecasted natural gas and attendant PJM energy prices.

Q. ARE THERE OTHER NON-MODELED, OR "QUALITATIVE" FACTORS THAT WOULD ALSO SUGGEST THAT THE BIG SANDY UNIT I GAS CONVERSION IS THE SUPERIOR OPTION TO FILL THIS APPROXIMATE 250 MW CAPACITY AND ENERGY TRANCHE?

A. Yes. As also described by Company Witness Karrasch, factors such as Company ownership and asset control (versus potential performance risk associated with receiving power and energy via a purchase power arrangement) also represents a relative qualitative benefit that was not considered in this comparative 250 MW RFP economic evaluation, but would further validate that the Big Sandy Unit 1 gas conversion option is the best alternative.

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[14] 268 MW / (268 MW + 780 MW [50% share of Mitchell 1&2] + 393 MW [Rockport 1&2 purchase] + 58.5 MW ecoPower PPA) = 17.9%

B. 250 MW RFP BID ANALYSIS IN CASE NO. 2012-00578 AND ITS RELATIONSHIP TO THE ECONOMIC MODELING IN THIS CASE

Q. DID KENTUCKY POWER ALSO PERFORM AN ANALYSIS OF THE 250 MW RFP BIDS AS PART OF CASE NO. 2012-00578?

A. Yes, although a few of the inputs were different. To review, on May 28, 2013, the Commission ordered Kentucky Power to submit, no later than June 28, 2013, an analysis of the bids received in response to its 250 MW RFP. The purpose of this analysis was to assist the Commission in evaluating the relative economics of the proposed transfer to Kentucky Power of a 50% undivided interest in the Mitchell generating station. On June 28, 2013 Kentucky Power filed with the Commission an analysis of the conforming 250 MW RFP responses compared to the planned Big Sandy Unit 1 conversion as well as a "stacking analysis" comparing a combination of the conforming bids to the Mitchell Transfer option.

Q. PLEASE OFFER A SUMMARY OF THESE RELATIVE BIG SANDY UNIT 1 EVALUATIONS THAT WERE PERFORMED AS PART OF CASE NO. 2012-00578.

A. Exhibit SCW-2 offers a tabular summarization and comparison of the modeling results for the three Kentucky Power disposition options for Big Sandy Unit 1 identified on TABLE 1 and as previously presented in Case No. 2012-00578.[15] Using the results of the analysis of the 250 MW RFP first offered in Case No. 2012-00578, the Company's lowest-cost resource alternative, which includes the Big Sandy Unit 1 gas conversion as well as the transfer to Kentucky Power of an undivided 50% interest in Mitchell Units 1 and 2 (Option #1), was validated as the recommended

[15] *See* "Exhibit SCW-1S" of the supplement testimony of S.C. Weaver in Case No. 2012-00578.

long-term Big Sandy Unit 1 (and Unit 2) disposition plan. First, as summarized on the second line of data found on Exhibit SCW-2, the relative CPW economic cost of the option which, instead of selecting a Big Sandy Unit 1 gas conversion, assumed an approximate 250 MW incremental purchase of capacity and energy from the Fundamentals-forecasted *PJM* market for as long as 10 years (Option #2A) is +$195 million.

Q. PLEASE OFFER FURTHER ELABORATION ON THESE RESULTS SUMMARIZED ON EXHIBIT SCW-2.

[redacted] Focusing further on (Confidential) Exhibit SCW-2A, detail is also offered identifying the relative study period CPW cost differences between a Kentucky Power resource portfolio that would include the Big Sandy Unit 1 gas conversion (Option #1) versus [redacted] non-affiliate proposals received via the March 28th 250 MW RFP. [redacted]

Q. WHY IS THERE A SLIGHT CHANGE IN THE 250 MW RFP MODELING RESULTS OFFERED IN THIS CASE FROM THOSE PREPARED AS PART OF CASE NO. 2012-00578?

A. The non-material changes in modeled CPW results derive from changes in two of the key inputs to the Strategist® model that occurred subsequent to the issuance of supplemental testimony in Case No. 2012-00578.

First, this summer the AEP Economic Forecasting group internally-published an updated Kentucky Power long-term load and peak demand forecast. I have summarized that updated load forecast in Exhibit SCW-3. This latest forecast now suggests a 0.30 percent compound annual growth rate in long-term (2013-2032) peak demand for Kentucky Power; while the prior forecast had projected a slightly higher 0.54 percent compound annual growth rate for a similar long-term period.[16]

Second, in late-August of this year the AEP Fundamental Analysis group internally-published an updated long-term forecast of various commodity pricing (e.g., regional on-peak/off-peak energy, natural gas, [various] coals, PJM capacity). That updated forecast, along with a graphical comparison of the underpinning long-term (Henry Hub) natural gas commodity prices utilized in Case No. 2012-00578, are summarized in Exhibit SCW-4. In general while projected natural gas—and attendant energy pricing—were slightly reduced in this latest forecast update, the longer-term differences in those projections were not significant.

In general, the latest modeling largely served to confirm the previous 250 MW RFP analysis.

VII. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY FROM THE PERSPECTIVE OF THE BIG SANDY UNIT 1 DISPOSITION ANALYSES PERFORMED.

A. Based on the relative economic modeling performed as well as the additional qualitative factors offered by Company Witnesses Wohnhas and Karrasch, it is in the long-term interest of Kentucky Power's customers to take advantage of the existing

[16] See Case No. 2012-00578, Weaver direct, Exhibit SCW-1, page 3 of 15.

Big Sandy Unit 1 infrastructure by effectively preserving its (PJM) capacity and energy contribution by way of a relative low-cost capital investment that would convert the unit from a coal-burning asset to one that would exclusively burn natural gas by mid-May of 2016; thereby allowing it to continue to operate this well-performing asset beyond the MATS Rule implementation deadline.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

Kentucky Power Company

Big Sandy Unit 1 Disposition Analysis -- Summary *

Cumulative Present Worth (CPW) of Modeled Revenue Requirements, 28-Year Study Period (2013-2040), Expressed in 2013$

OPTION	($000) OPTION Description	(A) KPCo Revenue Requirement (Excl. ICAP)	*Less:* (B) ICAP Revenue / <Cost>	= (C)=(A)-(B) KPCo Revenue Requirement, Net	(D) KPCo Revenue Requirement (Ex. ICAP) *v. Option #1*	*Less:* (E) ICAP Revenue / <Cost> *v. Option #1*	= (F)=(D)-(E) KPCo Revenue Requirement, Net *v. Option #1*
#1	Big Sandy 1 Natural Gas Conversion (7/2015)	6,127,071	179,467	5,947,603	-	-	-
#2A	Big Sandy 1 Retirement (6/2015), w/ (PJM) Market Replacement	6,156,422	75,222	6,081,201	29,351	(104,246)	**133,597**
#2B	Big Sandy 1 Retirement (6/2015), w/ (250 MW RFP) Market Replacement via the "Lowest Cost" CONFORMING OFFER received in response to the 250 MW RFP:	6,137,843	207,123	5,930,721	10,772	27,655	**(16,883)**

* Note: ALL analyses include, as part of Kentucky Power's nearer-term resource portfolio:

- o Continuation of 393 MW Rockport Purchase;
- o 50% Mitchell Transfer eff: 1/2014
- o Retirement of BS Unit 2 eff: 6/2015;
- o 58.5 MW ecoPower Hazard, LLC biomass renewable energy purchase eff: 1/2017; and
- o DSM assumptions per Exhibit SCW-1; Table 1-2 Case No. 2012-00578

Kentucky Power Company

Big Sandy Unit 1 Disposition Analysis -- CONFIDENTIAL Summary *

Cumulative Present Worth (CPW) of Modeled Revenue Requirements, 28-Year Study Period (2013-2040), Expressed in 2013$

OPTION	($000) OPTION Description	(A) KPCo Revenue Requirement (Excl. ICAP)	*Less:* (B) ICAP Revenue / <Cost>	= (C)=(A)-(B) KPCo Revenue Requirement, Net	(D) KPCo Revenue Requirement (Ex. ICAP) *v. Option #1*	*Less:* (E) ICAP Revenue / <Cost> *v. Option #1*	= (F)=(D)-(E) KPCo Revenue Requirement, Net *v. Option #1*
#1	Big Sandy 1 Natural Gas Conversion (7/2015)	6,127,071	179,467	5,947,603	-	-	-
#2A	Big Sandy 1 Retirement (6/2015), w/ (PJM) Market Replacement	6,156,422	75,222	6,081,201	29,351	(104,246)	**133,597**
	Relative % Change						*2.25%*
#2B	Big Sandy 1 Retirement (6/2015), w/ (250 MW RFP) Market Replacement via the following (mutually-exclusive) CONFORMING OFFERS received in response to the 250 MW RFP:						

[redacted]

* Note: ALL analyses include, as part of Kentucky Power's nearer-term resource portfolio:

- Continuation of 393 MW Rockport Purchase;
- 50% Mitchell Transfer eff: 1/2014
- Retirement of BS Unit 2 eff: 6/2015;
- 58.5 MW ecoPower Hazard, LLC biomass renewable energy purchase eff: 1/2017; and
- DSM assumptions per Exhibit SCW-1; Table 1-2 Case No. 2012-00578

[redacted]

ORIGINAL RESULTS REPRODUCED FROM CASE NO. 2012-00578

Kentucky Power Company

Big Sandy Unit 1 Disposition Analysis -- Summary *

Cumulative Present Worth (CPW) of Modeled Revenue Requirements, 28-Year Study Period (2013-2040), Expressed in 2013$

OPTION	($000) OPTION Description	(A) KPCo Revenue Requirement (Excl. ICAP)	(B) ICAP Revenue / <Cost>	(C)=(A)-(B) KPCo Revenue Requirement, Net	(D) KPCo Revenue Requirement (Ex. ICAP) *v. Option #1*	(E) ICAP Revenue / <Cost> *v. Option #1*	(F)=(D)-(E) KPCo Revenue Requirement, Net *v. Option #1*
#1	Big Sandy 1 Natural Gas Conversion (7/2015)	6,261,339	59,448	6,201,891	-	-	-
#2A	Big Sandy 1 Retirement (6/2015), w/ (PJM) Market Replacement	6,355,890	(40,824)	6,396,713	94,550	(100,272)	**194,822**
#2B	Big Sandy 1 Retirement (6/2015), w/ (250 MW RFP) Market Replacement via the "Lowest Cost" CONFORMING OFFER received in response to the 250 MW RFP:	6,299,925	93,796	6,206,129	38,586	34,348	**4,237**

* Note: In addition, ALL offer-specific analyses include, as part of Kentucky Power's nearer-term resource portfolio:

- o Continuation of 393 MW Rockport Purchase;
- o 50% Mitchell Transfer eff: 1/2014
- o Retirement of BS Unit 2 eff: 6/2015; and
- o DSM assumptions per Exhibit SCW-1; Table 1-2 Case No. 2012-00578

Exhibit SCW-2

ORIGINAL RESULTS REPRODUCED FROM CASE NO. 2012-00578

CONFIDENTIAL & BUSINESS SENSITIVE

Kentucky Power Company

Big Sandy Unit 1 Disposition Analysis -- CONFIDENTIAL Summary *

Cumulative Present Worth (CPW) of Modeled Revenue Requirements, 28-Year Study Period (2013-2040), Expressed in 2013$

OPTION	($000) OPTION Description	(A) KPCo Revenue Requirement (Excl. ICAP)	(B) ICAP Revenue / <Cost>	(C)=(A)-(B) KPCo Revenue Requirement, Net	(D) KPCo Revenue Requirement (Ex. ICAP) *v. Option #1*	(E) ICAP Revenue / <Cost> *v. Option #1*	(F)=(D)-(E) KPCo Revenue Requirement, Net *v. Option #1*
#1	Big Sandy 1 Natural Gas Conversion (7/2015)	6,261,339	59,448	6,201,891	-	-	-
#2A	Big Sandy 1 Retirement (6/2015), w/ (PJM) Market Replacement	6,355,890	(40,824)	6,396,713	94,550	(100,272)	**194,822**
#2B	Big Sandy 1 Retirement (6/2015), w/ (250 MW RFP) Market Replacement via the following (mutually-exclusive) CONFORMING OFFERS received in response to the 250 MW RFP:						

[redacted]

* Note: In addition, ALL offer-specific analyses include, as part of Kentucky Power's nearer-term resource portfolio:
- o Continuation of 393 MW Rockport Purchase;
- o 50% Mitchell Transfer eff: 1/2014
- o Retirement of BS Unit 2 eff: 6/2015; and
- o DSM assumptions per Exhibit SCW-1; Table 1-2 Case No. 2012-00578

Exhibit SCW-2A

Kentucky Power Company and AEP-East
Projected (Summer) Peak Demand and Internal Load
July 2013 Load Forecast, BEFORE Passive (& Active) DSM

	(Summer) Peak Demand (MW)		Internal Load (GWh)	
Year	KPCo[A]	AEP-East[A][B]	KPCo	AEP-East[B]
2013	1,107	19,978	7,083	121,665
2014	1,098	19,643	7,004	118,214
2015	1,101	19,767	7,014	118,919
2016	1,104	19,849	7,043	119,483
2017	1,108	19,935	7,056	119,877
2018	1,111	20,018	7,066	120,240
2019	1,114	20,103	7,077	120,720
2020	1,116	20,174	7,092	121,201
2021	1,122	20,345	7,108	121,813
2022	1,128	20,478	7,133	122,462
2023	1,131	20,565	7,154	123,104
2024	1,132	20,639	7,169	123,675
2025	1,139	20,822	7,187	124,317
2026	1,144	20,957	7,209	124,955
2027	1,149	21,103	7,231	125,645
2028	1,152	21,213	7,255	126,355
2029	1,159	21,372	7,283	127,144
2030	1,165	21,535	7,313	127,934
2031	1,170	21,689	7,335	128,670
2032	1,172	21,780	7,351	129,314

Note: In the Internal Load table, the 2013 year is labelled 2013[C].

10-Year (2013-2022):	KPCo	AEP-East
Total Growth	20	499
Compound Annual Growth Rate	0.20%	0.27%

20-Year (2013-2032):	KPCo	AEP-East
Total Growth	65	1,801
Compound Annual Growth Rate	0.30%	0.46%

10-Year (2013-2022):	KPCo	AEP-East
Total Growth	50	796
Compound Annual Growth Rate	0.08%	0.07%

20-Year (2013-2032):	KPCo	AEP-East
Total Growth	269	7,649
Compound Annual Growth Rate	0.20%	0.32%

(A) Represents 'PJM-Coincident' peak demand

(B) Includes combined KPCo, APCo, I&M and AEP-Ohio 'Wires' (Competitive Choice) peak demand & load

(C) Reflects 5 months actual, 7 months forecast

Summary of Long-Term Commodity Price Forecast
Used in Kentucky Power Strategist® Modeling

(Source: AEP Fundamental Analysis; August 2013)

Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars

	NATURAL GAS (Henry Hub) ($/MMBtu)	CO2 ($/Metric Tonne)	NAPP (6.0#) ($/Ton-FOB Mine)	CAPP (1.6#) ($/Ton-FOB Mine)
	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022
2013	4.04	0.00	55.00	63.46
2014	5.05	0.00	57.00	68.42
2015	5.47	0.00	59.00	72.39
2016	5.83	0.00	61.00	73.25
2017	6.01	0.00	71.14	74.60
2018	6.12	0.00	75.06	77.38
2019	6.19	0.00	79.83	81.77
2020	6.43	0.00	83.40	86.29
2021	6.75	0.00	83.50	86.35
2022	7.18	15.08	85.91	90.99
2023	7.30	15.28	88.34	94.43
2024	7.51	15.48	88.78	96.90
2025	7.75	15.67	88.63	99.97
2026	7.85	15.88	88.74	103.53
2027	8.04	16.08	89.30	105.71
2028	8.22	16.29	89.70	108.22
2029	8.41	16.50	89.90	112.66
2030	8.52	16.72	90.10	117.43
2031	8.73	16.94	91.10	119.98
2032	8.94	17.16	93.40	122.95
2033	9.16	17.38	97.39	126.16
2034	9.39	17.60	102.12	130.12
2035	9.61	17.84	105.59	133.27

	NATURAL GAS (Henry Hub) (REAL, 2011 $) ($/MMBtu)	ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)	OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)	Capacity Value (PJM-RTO RPM) * ($/MW-Day)
	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022	'BASE' Fleet Transition: CSAPR Carbon in 2022
2013	3.84	34.37	23.40	23.03
2014	4.70	37.94	24.50	85.05
2015	4.97	48.38	28.52	131.61
2016	5.16	55.92	34.10	91.30
2017	5.19	58.33	37.38	132.49
2018	5.16	59.02	38.37	199.74
2019	5.11	59.69	39.25	215.54
2020	5.18	61.51	40.76	231.74
2021	5.33	64.04	42.25	248.55
2022	5.54	72.74	53.89	265.99
2023	5.51	74.33	54.86	284.08
2024	5.54	75.87	56.20	302.83
2025	5.60	77.51	57.24	321.95
2026	5.55	78.86	58.16	341.74
2027	5.56	80.60	59.05	362.23
2028	5.57	81.99	60.20	383.42
2029	5.58	83.65	61.45	394.85
2030	5.54	84.41	62.69	403.15
2031	5.56	86.04	64.20	411.61
2032	5.57	88.14	66.16	420.26
2033	5.59	90.15	68.50	429.08
2034	5.62	88.94	70.00	438.09
2035	5.63	91.25	71.70	447.29

* Represents actual PJM-RPM Base Residual Auction market clearing prices through the 2016/17 PJM Planning Years, with the values shown being "blended" (i.e. ANNUAL) prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

Change in Natural Gas Prices (@ Henry Hub... $ per MMBtu)

UPDATED (8/2013) vs. Previous AEP Fundamental Analysis Forecast

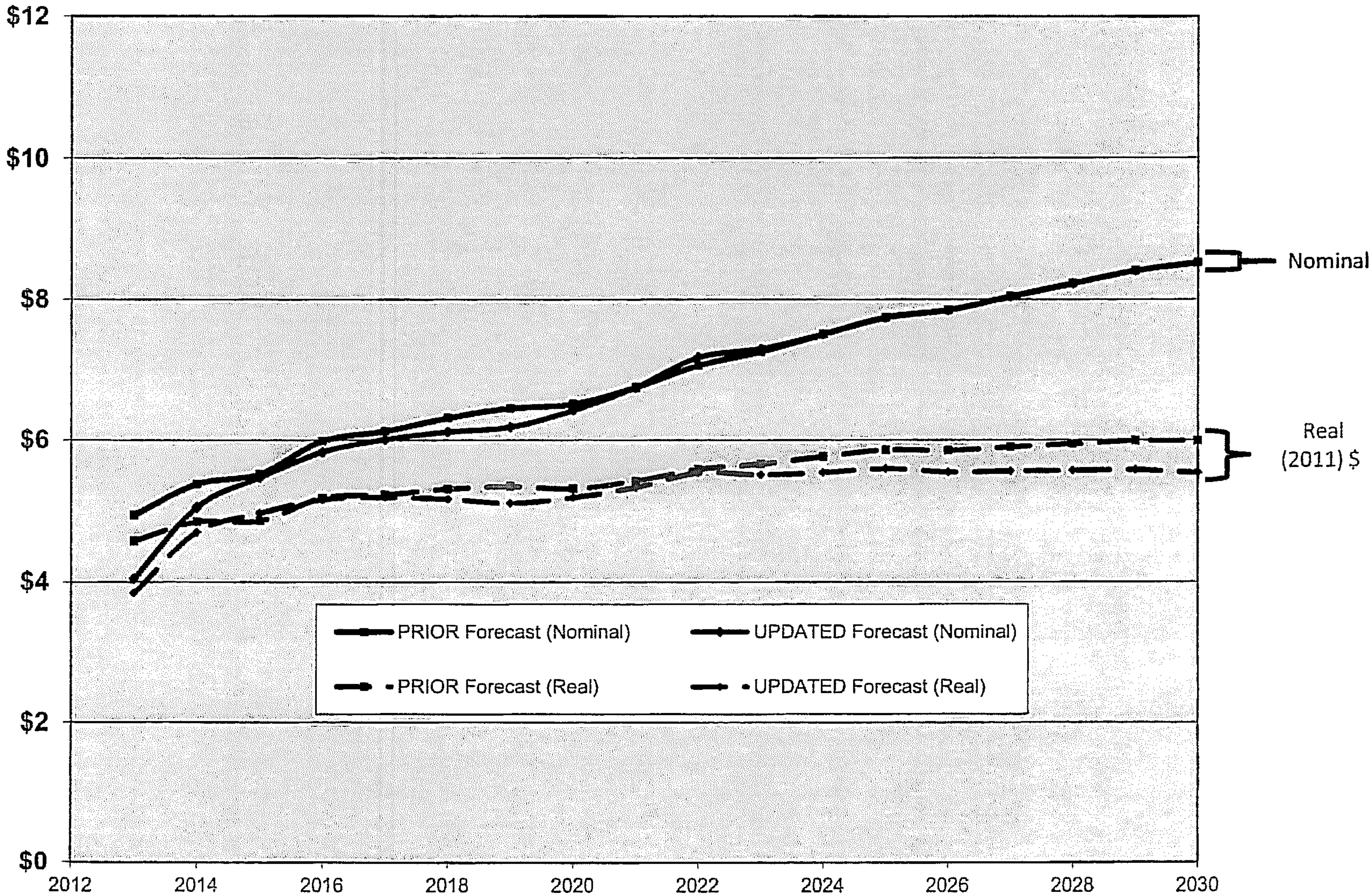

Exhibit SCW-4
Page 2 of 2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For:		
(1) A Certificate Of Public Convenience And Necessity	)	
Authorizing The Company To Convert Big Sandy Unit 1	)	Case No. 2013-000-
To A Natural Gas-Fired Unit; And (2) For All Other	)	
Required Approvals And Relief		

DIRECT TESTIMONY

OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY	)	
	)	SS
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 4th day of December 2013.

481393

Notary Public

My Commission Expires: January 23, 2017

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00___

TABLE OF CONTENTS

DIRECT TESTIMONY OF RANIE K. WOHNHAS, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. **PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q. **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.**

A. I earned a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power Company in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company ("APCo") working in rates. In 2001, I transferred to the American Electric Power ("AEP") Service Corporation ("AEPSC") working as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support with Kentucky Power and was promoted to Director in April 2006. I was promoted to my current position as Managing Director, Regulatory and Finance effective September 1, 2010.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR, REGULATORY AND FINANCE?**

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This includes planning and executing rate filings for both federal and state regulatory agencies and certificate of public convenience and necessity ("CPCN") filings before this Commission. I am also responsible for managing the Company's financial operating plans including various capital and O&M operational budgets that interface with all other AEP organizations affecting the Company's performance. As part of the financial strategy, I work with various AEPSC departments to ensure that adequate resources such as debt, equity and cash are available to build, operate, and maintain Kentucky Power's electric system assets providing service to our retail and wholesale customers. In my role as Managing Director, Regulatory and Finance, I report directly to Gregory G. Pauley, President and Chief Operating Officer of Kentucky Power.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I have testified before this Commission in various fuel proceedings and provided written testimony in the last three base rate case filings (Case Nos. 2005-00341, 2009-00459, and 2013-00197). I also provided written testimony and testified in the filing by AEP Kentucky Transmission Company, Inc. which sought public utility status (Case No. 2011-00042), and provided written testimony in support of the Company's application for a CPCN to construct the proposed Bonnyman-Soft Shell 138 kV transmission line and related facilities (Case No. 2011-00295). In addition, I provided written testimony and testified in Case No. 2011-00401, which included the Company's 2011 Environmental Compliance Plan, and request for approval of a CPCN for the construction and acquisition of related facilities. Most recently, I provided testimony in Case No. 2012-00226, which requested the withdrawal of Tariff RTP and approval of Rider RTP, Case No. 2012-00578, which sought approvals related to the transfer of a fifty percent interest in the Mitchell generating station to Kentucky Power, and Case No. 2013-00144, which requested approval of renewable energy purchase agreement for biomass energy.

III. PURPOSE OF TESTIMONY

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to provide an overview of Kentucky Power's request for a certificate of public convenience and necessity to convert the Company's existing Big Sandy Unit 1 from a coal-fired facility to a natural gas-fired unit. I also summarize the emerging environmental requirements driving the proposed conversion. I describe how the Big Sandy Unit 1 conversion comports with the Stipulation and Settlement Agreement approved as modified by the Commission in Case No. 2012-00578. Finally, I will describe the estimated customer rate impact of the Big Sandy Unit 1 conversion.

Q. **PLEASE IDENTIFY THE OTHER WITNESSES TESTIFYING IN SUPPORT OF KENTUCKY POWER'S APPLICATION IN THIS PROCEEDING.**

A. The other witnesses testifying on behalf of Kentucky Power are:

Witness	Subject Matter
Scott C. Weaver	Describes the Big Sandy Unit 1 disposition alternatives modeled, the modeling process used, and the resulting analyses.
Robert L. Walton	Provides a summary of the planned natural gas conversion, the project schedule, and development of the project cost estimate.
Joseph A. Karrasch	Describes the Company's March 31, 2013 RFP for 250 MW of capacity and energy, the conforming and non-confirming responses thereto, and the risks associated with market purchase alternatives.

IV. CONVERSION OF BIG SANDY UNIT 1

Q. PLEASE DESCRIBE KENTUCKY POWER'S PROPOSED CONVERSION OF BIG SANDY UNIT 1.

A. In order to comply with emerging environmental regulations, Kentucky Power proposes to convert Big Sandy Unit 1 to burn natural gas instead of coal. The conversion would require modifications to the boiler and burner at Big Sandy Unit 1 as well as the installation of the necessary natural gas pipeline infrastructure. As a result of the conversion, the capacity of Big Sandy Unit 1 will be reduced from 278 MW to 268 MW. Additional details regarding the planned conversion of Big Sandy Unit 1, including the project schedule and cost estimates, are provided in the testimony of Company Witness Walton.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL REGULATIONS DRIVING KENTUCKY POWER'S PROPOSED CONVERSION OF BIG SANDY UNIT 1.

A. On February 16, 2012, the United States Environmental Protection Agency ("EPA") published the Mercury and Air Toxics Standard ("MATS") Rule in the federal register. The goal of the MATS Rule is to reduce hazardous air pollutants ("HAPs") from coal- and oil-fired electric generating units. The final rule includes stringent emission limits for mercury, particulate matter (as a surrogate for non-mercury metals), as well as hydrochloric acid or sulfur dioxide (as surrogates for acid gases).

Q. WHAT IS THE EFFECT OF THE MATS RULE ON BIG SANDY UNIT 1?

A. The MATS Rule establishes stringent, unit-specific emission limits applicable to Big Sandy Unit 1. To comply with the MATS limits, Kentucky Power would need to install additional, costly emission control equipment at Big Sandy Unit 1 (in the form of flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") technology), switch fuels or retire the unit. MATS does not apply to natural gas-fired units.

Q. WHAT IS THE COMPLIANCE TIMELINE FOR THE MATS RULE?

A. The initial MATS compliance date is April 16, 2015, three years after the effective date of the rule. However, up to a one-year administrative extension of the initial compliance date (a fourth year) can be granted by a state's air quality agency for units undertaking major retrofit or replacement projects, or for units that will retire but are required for reliability purposes. An additional one year extension (a fifth year) via an Enforcement Order from EPA may also be available for units identified as "critical for reliability purposes."

Q. WILL THE BIG SANDY UNIT 1 CONVERSION BE COMPLETE BY THE APRIL 16, 2015 COMPLIANCE DATE?

A. No. Because the resolution of Case No. 2012-00578 and the requested transfer of a 50% undivided interest in Mitchell generating station was such a critical component of Kentucky Power's long-term resource planning process, it was prudent to wait for final resolution of that case prior to finalizing the application in this case. With the Commission's November 15, 2013 Order denying the Attorney General's petition for rehearing, that has occurred. As described in more detail in the testimony of Company Witness Walton, the timing of the resolution of Case No. 2012-00578, along with other resulting factors, means that the Big Sandy Unit 1 conversion will not be complete by April 16, 2015. Accordingly, the Company will request, consistent with the MATS Rule, up to a one-year extension of the compliance date from the Kentucky Division for Air Quality.

V. STIPULATION AND SETTLEMENT AGREEMENT IN CASE NO. 2012-00578

Q. PLEASE DESCRIBE THE STIPULATION AND SETTLEMENT AGREEMENT IN CASE NO. 2012-00578 AS IT RELATES TO THIS FILING.

A. On July 2, 2013 the Company, Kentucky Industrial Utility Customers, Inc. and Sierra Club filed a Stipulation and Settlement Agreement with the Commission in Case No. 2012-00578. The Stipulation and Settlement Agreement addressed a number of issues, including the disposition of Big Sandy Unit 1 and Big Sandy Unit 2. Paragraph 13 of the Stipulation and Settlement Agreement addresses the Big Sandy Unit 1 Conversion:

> *13. The Company shall file with the Commission an application pursuant to KRS 278.020 for Certificate of Public Convenience of [sic] Necessity to convert the 268 MW Big Sandy Unit 1 to natural gas, and will exercise its option to terminate its March 28, 2013 Request for Proposals. All parties to this Settlement Agreement agree they will not move to intervene in the Company's filing for the required Certificate of Public Convenience and Necessity to convert Big Sandy Unit 1 to natural gas, provide the cost to convert is approximately $60 million.*

On October 7, 2013, the Commission issued an Order approving the Stipulation and Settlement Agreement, subject to modifications unrelated to Paragraph 13, set forth in an appendix to the Order. On October 14, 2013, Kentucky Power accepted the modifications set forth in the appendix to the Order.

With this filing Kentucky Power has complied with its obligations under Paragraph 13 of the Commission approved Stipulation and Settlement Agreement.

Q. IS COMPLIANCE WITH THE STIPULATION AND SETTLEMENT AGREEMENT THE ONLY REASON KENTUCKY POWER IS FILING THIS APPLICATION?

A. No. Kentucky Power is seeking approval to convert Big Sandy Unit 1 to natural gas because it is the best alternative for the Company to meet its long term energy and capacity needs in the face of emerging environmental regulations. The Big Sandy Unit 1 conversion represents the best option for Kentucky Power going forward for a number of reasons. First, as described in detail in the testimony of Company Witness Weaver, the Big Sandy Unit 1 Conversion alternative is *a* least cost option for the disposition of Big Sandy Unit 1. Second, as described in the testimony of Company Witness Karrasch, the Big Sandy Unit 1 conversion option protects the Company and its ratepayers from the risk attendant to utilizing a market alternative (from the RFP) to meet the Company's capacity and energy needs. Third, the Big Sandy Unit 1 conversion allows Kentucky Power to diversify the fuel source mix in its generation portfolio. If the conversion is authorized, the Company's fuel source mix would consist of approximately 78% coal from the Mitchell and Rockport facilities, 18% natural gas from Big Sandy Unit 1, and 4% renewables from the ecoPower biomass facility. Finally, the conversion of Big Sandy Unit 1 will allow the continued operation of a Kentucky Power generating unit in Lawrence County, Kentucky.

VI. <u>ESTIMATED COST OF SERVICE IMPACTS</u>

Q. HAS THE COMPANY ESTIMATED THE RELATIVE IMPACT ON THE COST OF SERVICE DUE TO THE BIG SANDY UNIT 1 CONVERSION?

A. Yes, the Company has estimated the first-year cost of service impacts of the Big Sandy Unit 1 conversion utilizing the Company's jurisdictional revenues for the twelve-month period ending September 30, 2013. This analysis includes the effects attributable to the capital costs to convert Big Sandy Unit 1 to natural gas and to the changes in operations and maintenance costs and fuel costs associated with the switch from coal to natural gas. As shown on **Exhibit RKW-1**, the estimated cost of service impact of the Big Sandy

Unit 1 conversion would be approximately 2.13% as compared to the twelve month period ending September 30, 2013.

Q. **WHAT WILL BE THE TOTAL ESTIMATED COST OF SERVICE IMPACT TO ADDRESS THE EMERGING ENVIRONMENTAL REGULATIONS AT THE BIG SANDY PLANT AS A WHOLE?**

A. As further shown on **Exhibit RKW-1**, the estimated cost of service impact of the disposition options selected by the Company to address its obligations under emerging environmental regulations at the Big Sandy Plant, based on the Company's jurisdictional revenues for the twelve-month period ending September 30, 2013, is 15.12%. This includes an estimated 12.72% associated with the transfer of an undivided 50% interest in the Mitchell generating station pursuant to the terms of the Stipulation and Settlement Agreement approved as modified by the Commission in Case No. 2012-00578 in addition to the estimated impact from the Big Sandy Unit 1 conversion.

Q. **DOES THIS ANALYSIS TAKE INTO ACCOUNT THE COSTS OF RETIRING THE COAL-RELATED COMPONENTS OF BIG SANDY UNIT 1?**

A. Yes. As required by Paragraph 14 of the Commission-approved Stipulation and Settlement Agreement the Company will recover the coal-related retirement costs of Big Sandy Unit 1 (along with the costs of retiring Big Sandy Unit 2) on a levelized basis, including a weighted average cost of capital ("WACC") carrying cost, over a 25 year period beginning when base rates are set in the Company's next base rate case. The Company will use its best efforts to minimize the costs of dismantling the coal-related components of Big Sandy Unit 1 and to maximize salvage credits. These retirement costs will be recovered through a new rider, the Asset Transfer Rider-2.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 4th day of December 2013.

Judy K. Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

CASE NO: 2013-00430

CONTAINS

LARGE OR OVERSIZED

MAP(S)

RECEIVED ON: December 6, 2013