Big Sandy Plant Unit 1
Repowering Cost Estimate Study

Prepared for:
Kentucky Power Company (Owner)
and American Electric Power Service Corporation

Project No. 12756-002
September 16, 2011

Summary Report

Sargent & Lundy LLC

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Issue Summary Page

Revision Number	Date	Purpose	Prepared By	Reviewed By	Approved By	Pages Affected
A	07/29/11	Comments	A. A. Baker K. Nomanbhoy T. J. Muszalski C. L. Woods S. R. Wylie	D. F. Franczak M. N. Ozan	S. R. Bertheau	All
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EXECUTIVE SUMMARY

The purpose of this document is to establish for American Electric Power (AEP) the Basis of the Repowered Combined Cycle Plant conceptual design and resultant Capital Cost Estimates prepared for Big Sandy Plant Unit 1, located in Louisa, Kentucky.

The Repowered Combined Cycle Plant options that were considered for this study are described as follows:

Option 1: 2x2x1 Combined Cycle Plant: Mitsubishi M501GAC Combustion Turbines
Option 2: 2x2x1 Combined Cycle Plant: General Electric 7FA.05 Combustion Turbines

Both configurations options reuse the existing steam turbine generator, condenser and cooling tower (and other equipment as defined in the study deliverables). These options were required to be developed without affecting the operations of the existing Unit 1 (until its scheduled date for final shutdown) and Unit 2 coal plants at Big Sandy. Also, plant areas designated for the future Unit 2 flue gas desulfurization (FGD) system were to be avoided.

The Design Basis/Criteria for the repowered combined cycle plant was based on the Combined Cycle Brownfield Build Cost Estimate Study (as modified by the repowered plant configuration differences) and design basis information provided by AEP in written and verbal communication and discussions at project design review meetings.

The Option 1 Big Sandy Repowered Combined Cycle Plant is a 2x2x1 Combined Cycle Facility configured with two (2) Mitsubishi 501GAC combustion turbines. The heat recovery steam generators are provided with duct burners with approximately 57 MW of duct fired capacity (limited only by the steam turbine and condenser). Natural gas is the primary fuel with fuel oil backup as an option.

The Option 2 Big Sandy Repowered Combined Cycle Plant is a 2x2x1 Combined Cycle Facility configured with two (2) General Electric (GE) 7FA.05 combustion turbines. Except for the combustion turbines Option 2 is similar to Option 1. The heat recovery steam generators are provided with duct burners with approximately 109 MW of duct fired capacity (limited only by the steam turbine and condenser).

Based on heat balances prepared, the Option 1 and 2 plant performance design basis for natural gas and fuel oil is tabulated in Tables ES-1 and ES-2 respectively.

Table ES-1

OPTION 1& 2 PLANT PERFORMANCE DESIGN BASIS – NATURAL GAS

OPTION 1 MITSUBISHI M501GAC COMBUSTION TURBINES	NATURAL GAS			
CASE NUMBER	CASE 1	CASE 8	CASE 9	CASE 7
DESCRIPTION	ANNUAL AVERAGE UNFIRED	ANNUAL AVERAGE FIRED	WINTER EXTREME FIRED	PJM DESIGN FIRED W/ CHILLERS
AMBIENT DB/WB (F°)	55 / 49	55 / 49	5 / 3.5	91 / 74
NET PLANT OUTPUT (kW)	744,808	801,547	862,769	781,920
NET PLANT HEAT RATE, HHV (Btu/kWh)	6,862	7,042	7,027	7,161

OPTION 2 GE 7FA.05 COMBUSTION TURBINES	NATURAL GAS			
CASE NUMBER	CASE 1	CASE 8	CASE 9	CASE 7
DESCRIPTION	ANNUAL AVERAGE UNFIRED	ANNUAL AVERAGE FIRED	WINTER EXTREME FIRED	PJM DESIGN FIRED W/ CHILLERS
AMBIENT DB/WB (F°)	55 / 49	55 / 49	5 / 3.5	91 / 74
NET PLANT OUTPUT (kW)	601,776	710,291	746,910	692,159
NET PLANT HEAT RATE, HHV (Btu/kWh)	6,830	7,234	7,259	7,362

Table ES-2

OPTION 1 & 2 PLANT PERFORMANCE DESIGN BASIS – FUEL OIL

OPTION 1 MITSUBISHI M501GAC COMBUSTION TURBINES	FUEL OIL	
CASE NUMBER	CASE 14	CASE 15
DESCRIPTION	ANNUAL AVERAGE UNFIRED	WINTER EXTREME UNFIRED
AMBIENT DB/WB (F°)	55 / 49	5 / 3.5
NET PLANT OUTPUT (kW)	595,972	587,579
NET PLANT HEAT RATE, HHV (Btu/kWh)	7,294	7,398

OPTION 2 GE 7FA.05 COMBUSTION TURBINES	FUEL OIL	
CASE NUMBER	CASE 14	CASE 15
DESCRIPTION	ANNUAL AVERAGE UNFIRED	WINTER EXTREME UNFIRED
AMBIENT DB/WB (F°)	55 / 49	5 / 3.5
NET PLANT OUTPUT (kW)	632,530	627,576
NET PLANT HEAT RATE, HHV (Btu/kWh)	7,124	7,180

The cost estimates were based upon conceptual design deliverables prepared by S&L for each configuration option. The conceptual design deliverables, consisting of project site plot plans, general arrangements, piping and instrument diagrams, water balances and electrical one-lines, formed the basis for development of preliminary major equipment sizes and commodity estimates. Attention was focused on the significant elements that changed from Option 1 to Option 2, primarily the combustion turbines and resultant change in system/equipment capacities. The arrangements of the combined cycle plant were kept the same to the maximum extent practical for each configuration option.

The results of the capital cost estimates prepared for Option 1 and 2 are tabulated in the following tables. Costs are tabulated without (Table ES-3) and with (Table ES-4) escalation and contingency. These total costs do not include costs to be developed by AEP.

Table ES-3

OPTION 1 & 2 CAPITAL COST ESTIMATE COMPARISON SUMMARY (EXCLUDES ESCALATION AND CONTINGENCY)

OPTION 1 MITSUBISHI M501GAC COMBUSTION TURBINES	TOTAL EQUIPMENT COSTS	TOTAL MATERIAL COSTS	TOTAL CONSTRUCTION & ERECTION COSTS	TOTAL PROJECTED COSTS
SUBTOTAL PROJECT COSTS	$307,519,985	$70,388,423	$166,809,438	$544,717,846
PROJECT INDIRECT COSTS				$42,947,000
TOTAL PROJECT COST (LESS ESCALATION & CONTINGENCY)				$587,664,846

OPTION 2 GE 7FA.05 COMBUSTION TURBINES	TOTAL EQUIPMENT COSTS	TOTAL MATERIAL COSTS	TOTAL CONSTRUCTION & ERECTION COSTS	TOTAL PROJECTED COSTS
SUBTOTAL PROJECT COSTS	$270,788,675	$68,478,064	$158,373,028	$497,639,767
PROJECT INDIRECT COSTS				$42,254,700
TOTAL PROJECT COST (LESS ESCALATION & CONTINGENCY)				$539,894,467

Table ES-4

OPTION 1 & 2 CAPITAL COST ESTIMATE COMPARISON SUMMARY (INCLUDES ESCALATION AND CONTINGENCY)

OPTION 1 MITSUBISHI M501GAC COMBUSTION TURBINES	TOTAL EQUIPMENT COSTS	TOTAL MATERIAL COSTS	TOTAL CONSTRUCTION & ERECTION COSTS	TOTAL PROJECTED COSTS
SUBTOTAL PROJECT COSTS	$307,519,985	$70,388,423	$166,809,438	$544,717,846
PROJECT INDIRECT COSTS				$42,947,000
ESCALATION				$56,305,259
CONTINGENCY				$76,810,500
TOTAL PROJECT COST				$720,780,605

OPTION 2 GE 7FA.05 COMBUSTION TURBINES	TOTAL EQUIPMENT COSTS	TOTAL MATERIAL COSTS	TOTAL CONSTRUCTION & ERECTION COSTS	TOTAL PROJECTED COSTS
SUBTOTAL PROJECT COSTS	$270,788,675	$68,478,064	$158,373,028	$497,639,767
PROJECT INDIRECT COSTS				$42,254,700
ESCALATION				$51,986,300
CONTINGENCY				$71,834,100
TOTAL PROJECT COST				$663,714,867

The combined cycle plant conceptual design includes fuel oil firing capability. The Option 1 and 2 cost estimates include all underground fuel oil piping in the base costs as well as the CTG costs for dual-fuel firing. A separate optional cost estimate was prepared for the fuel oil storage facility, which includes two (2) fuel oil storage tanks, an unloading facility, fuel oil forwarding pumps and a demineralized water storage tank. Also any required aboveground fuel and oil piping is included in this cost estimate. Table ES-5 tabulates this optional cost for fuel oil firing.

Table ES-5

FUEL OIL OPTION CAPITAL COST ESTIMATE SUMMARY

FUEL OIL OPTION	TOTAL EQUIPMENT COSTS	TOTAL MATERIAL COSTS	TOTAL CONSTRUCTION & ERECTION COSTS	TOTAL PROJECTED COSTS
SUBTOTAL PROJECT COSTS	$6,046,998	$2,227,297	$4,924,813	$13,199,108
PROJECT INDIRECT COSTS				$90,700
ESCALATION				$1,324,205
CONTINGENCY				$2,360,100
TOTAL PROJECT COST				$16,974,113

The Option 1 and 2 cost estimates include costs for specific equipment and materials included in the base conceptual design. Separate Takeout Pricing cost estimates were prepared to identify the costs included in the base cost estimates for these items. Table ES-6 provides a summary of the takeout pricing cost estimates.

Table ES-6

TAKEOUT PRICING SUMMARY

	TOTAL DIRECT & CONSTRUCTION INDIRECT COST	PROJECT INDIRECT COST	TOTAL COST IMPACT
FUEL OIL BASE	$10,880,536	$2,696,385	$13,576,921
CT INLET AIR CHILLERS	$22,512,740	$5,564,271	$28,077,011
CONDENSATE POLISHER	$3,824,847	$942,513	$4,767,360
AUXILIARY BOILER	$4,561,756	$1,100,550	$5,662,306
SERVICE WATER PIPING (SS vs CS)	$416,676	$97,543	$514,219
DCS HIGH FIDELITY SIMULATOR	$1,617,450	$402,615	$2,020,065
WATER TREATMENT SYSTEM	$10,904,691	$2,626,845	$13,531,536

Fixed and Variable Non-Fuel O&M costs were determined in accordance with the economic basis agreed to with AEP. Total fixed and variable costs were calculated on a yearly basis for the 30 year life of the plant. Levelized (over 30 years) fixed and variable O&M costs on a $/MWh basis were derived. The yearly fixed and variable costs for the first five years are identified in Table ES-7 for Option 1 and Table ES-8 for Option 2. A summary of the levelized O&M costs over 30 years for both Options is provided in Table ES-9.

Table ES-7

OPTION 1 FIXED & VARIABLE NON-FUEL O&M COST SUMMARY FIRST 5 YEARS (2011 DOLLARS) – UNFIRED (745 MW)

YEAR END DATE	31 – DEC - 16	31 – DEC - 17	31 – DEC - 18	31 – DEC - 19	31 – DEC - 20
OPERATING YEAR	1	2	3	4	5
TOTAL FIXED O&M COST (x $1,000s)	$9,605	$9,819	$10,038	$17,688	$10,493
TOTAL VARIABLE O&M COST (x $1,000s)	$9,088	$10,013	$10,980	$11,988	$13,040
TOTAL O&M COST (x $1,000s)	$18,692	$19,832	$21,018	$29,696	$23,534
FIXED O&M COST ($/kW/Yr)	$12.90	$13.18	$13.48	$23.75	$14.09
VARIABLE O&M COST ($/MWh)	$2.79	$2.86	$2.93	$3.00	$3.07
TOTAL FIXED & VARIABLE COST ($/MWh)	$5.73	$5.66	$5.60	$7.43	$5.55

Table ES-8

OPTION 2 FIXED & VARIABLE NON-FUEL O&M COST SUMMARY FIRST 5 YEARS (2011 DOLLARS) – UNFIRED (745 MW)

YEAR END DATE	31 – DEC - 16	31 – DEC - 17	31 – DEC - 18	31 – DEC - 19	31 – DEC - 20
OPERATING YEAR	1	2	3	4	5
TOTAL FIXED O&M COST (x $1,000s)	$9,283	$9,492	$9,707	$15,845	$10,153
TOTAL VARIABLE O&M COST (x $1,000s)	$7,815	$8,611	$9,442	$10,310	$11,214
TOTAL O&M COST (x $1,000s)	$17,098	$18,103	$19,149	$26,155	$21,367
FIXED O&M COST ($/kW/Yr)	$15.43	$15.77	$16.13	$26.33	$16.87
VARIABLE O&M COST ($/MWh)	$2.96	$3.04	$3.12	$3.19	$3.27
TOTAL FIXED & VARIABLE COST ($/MWh) – OPTION 1/2	$6.49	$6.39	$6.32	$8.10	$6.24

Table ES-9

**OPTION 1 & 2 FIXED & VARIABLE NON-FUEL O&M COST SUMMARY
LEVELIZED COST (2011 DOLLARS)**

OPTION 1 MITSUBISHI M501GAC COMBUSTION TURBINES	LEVELIZED COST (30YEARS) UNFIRED (745MW)	 FIRED (802MW)
FIXED O&M COST ($/kW/yr)	$ 20.64	$ 19.18
FIXED O&M COST ($/MWh)	$ 3.79	$ 3.52
VARIABLE O&M COST ($/MWh)	$ 3.59	$ 3.34
TOTAL O&M COST ($/MWh)	$ 7.39	$ 6.86

OPTION 2 GE 7FA.05 COMBUSTION TURBINES	LEVELIZED COST (30YEARS) UNFIRED (602MW)	 FIRED (710MW)
FIXED O&M COST ($/kW/yr)	$ 24.26	$ 20.55
FIXED O&M COST ($/MWh)	$ 4.46	$ 3.78
VARIABLE O&M COST ($/MWh)	$ 3.83	$ 3.24
TOTAL O&M COST ($/MWh)	$ 8.28	$ 7.02

A Level 2 Project Schedule was prepared for the project based on AEP's multi-prime contracting strategy. Based on the current anticipated filing date for the Certificate of Convenience and Necessity (CCN) of September 2, 2011 and the 270 days the Kentucky PSC has to act on the CCN filing, the project detailed design start date is set at June 1, 2012. The in-service date for the combined Cycle plant is December 31, 2015. All project activities that need to start prior to the June 1, 2012 date, to achieve the scheduled in-service date, are identified in the schedule.

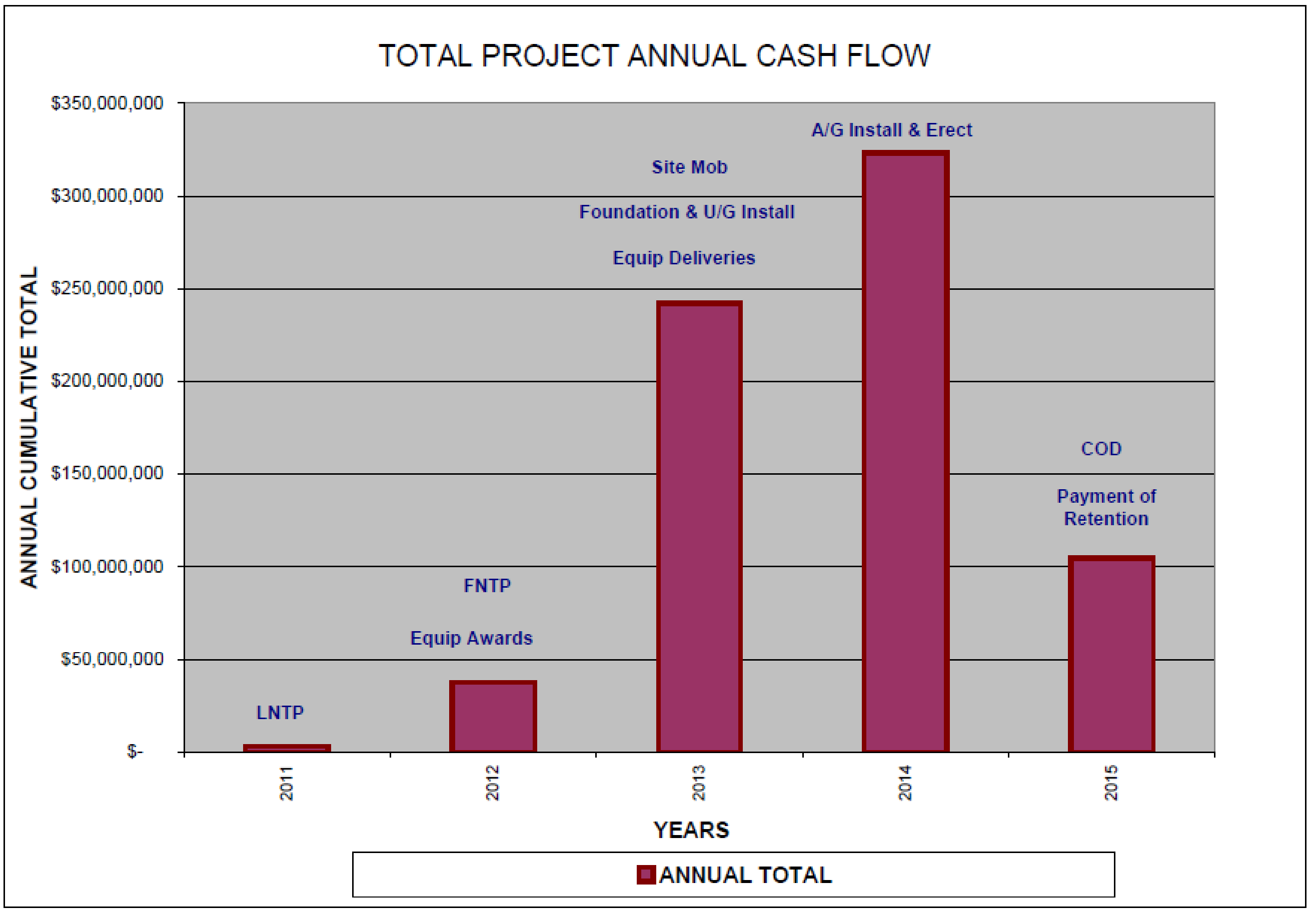
The schedule and cost information is summarized in Table ES-10 for Option 1 (similar for Option 2) which provide key milestone dates and annual cash flow data.

Table ES-10

PROJECT ANNUAL CASH FLOW SUMMARY

Kentucky Power Company & American Electric Power Service Corporation
Big Sandy U1 Repowering Study
(Option 1)

Sargent & Lundy
July 29, 2011
Rev: 0



1.0 INTRODUCTION

The purpose of this document is to establish for American Electric Power (AEP) the Basis of the Repowered Combined Cycle Plant conceptual design and resultant Capital Cost Estimates prepared for Big Sandy Plant Unit 1, located in Louisa, Kentucky. It is also intended to organize and present the deliverables for the Repowered Combined Cycle Plant that was used to develop the Capital Cost Estimates. This document defines the conceptual design process used to establish the project scope of work for each Combined Cycle Plant Configuration Option, the organization of the Capital Cost Estimate structure and the technical and commercial basis used to develop the Capital and O&M Cost Estimates. It also defines the assumptions used in preparing the cost estimates.

The Cost Estimate Study Report is comprised of one (1) volume as follows:

Volume	Description
1	Summary Report

The Repowered Combined Cycle Plant options that were considered for this study are described as follows:

Option 1: 2x2x1 Combined Cycle Plant: Mitsubishi M501GAC Combustion Turbines
Option 2: 2x2x1 Combined Cycle Plant: General Electric 7FA.05 Combustion Turbines

Both configuration options reuse the existing steam turbine generator, condenser and cooling tower (and other equipment as defined in the study deliverables). These options were required to be developed without affecting the operations of the existing Unit 1 (until its scheduled date for final shutdown) and Unit 2 coal plants at Big Sandy. Also, plant areas designated for the future Unit 2 flue gas desulfurization (FGD) system were to be avoided.

The Design Basis/Criteria for the repowered combined cycle plant was based on the Combined Cycle Brownfield Build Cost Estimate Study (as modified by the repowered plant configuration differences) and design basis information provided by AEP in written and verbal communication and discussions at project design review meetings.

The Option 1 Big Sandy Repowered Combined Cycle Plant is a 2x2x1 Combined Cycle Facility configured with two (2) Mitsubishi 501GAC combustion turbines. The heat recovery steam generators are provided with duct burners with approximately 57 MW of duct fired capacity (limited only by the steam turbine and condenser). Natural gas is the primary fuel with fuel oil backup as an option. Based on heat balances prepared for natural gas firing the net plant output for the Annual Average Unfired case is 744,808 kW and for the Annual Average Fired case is 801,547 kW. For fuel oil firing the net plant output for the Annual Average Unfired case is 595,972 kW and for the Winter Extreme Unfired case is 587,579 kW.

The Option 2 Big Sandy Repowered Combined Cycle Plant is a 2x2x1 Combined Cycle Facility configured with two (2) General Electric (GE) 7FA.05 combustion turbines. Except for the combustion turbines Option 2 is similar to Option 1. The heat recovery steam generators are provided with duct burners with approximately 109 MW of duct fired capacity (limited only by the steam turbine and condenser). Based on heat balances prepared for natural gas firing the net plant output for the Annual Average Unfired case is 601,776 kW and for the Annual Average Fired case is 710,291 kW. For fuel oil firing the net plant output for the Annual Average Unfired case is 632,530 kW and for the Winter Extreme Unfired case is 627,576 kW.

The cost estimates were based upon conceptual design deliverables prepared by S&L for each configuration option. The conceptual design deliverables, consisting of project site plot plans, general arrangements, piping and instrument diagrams, water balances and electrical one-lines, formed the basis for development of preliminary major equipment sizes and commodity estimates. Attention was focused on the significant elements that changed from Option 1 to Option 2, primarily the combustion turbines and resultant change in system/equipment capacities. The arrangements of the combined cycle plant were kept the same to the maximum extent practical for each configuration option.

Information from studies performed initially by AEP and other organizations, as defined later, were also used in development of this study.

2.0 TECHNICAL BASIS

The Design Basis used to establish the project scope of work and the conceptual design was developed through a process of Design Review Meetings held with the project team members and site walkdowns and investigations. As the conceptual design deliverables matured in development they were reviewed with AEP in detail. The meetings focused on the scope of major equipment, system design attributes, equipment redundancy, systems and equipment to be reused and operation/maintenance requirements. The Repowered Combined Cycle Plant design basis used for the conceptual design is the same established by AEP for the Combined Cycle Brownfield Build Cost Estimate Study, adjusted to meet the requirements of the repowered design. Additional Design Basis documents were provided by AEP for use in establishing the design and scope and are not attached to this report.

Equipment Lists were prepared to identify engineered equipment and systems reflected on the general arrangements, P&ID’s, electrical one-lines and other documents reviewed at the design review meetings. The conceptual design deliverables prepared for this study are tabulated in the Project Deliverable Index (Exhibit 1-4).

2.1 Site Plan and General Arrangement Drawings

For each repowered configuration option Site Plans and General Arrangements were prepared to identify the layout of each configuration option and to define the major components of the combined cycle plant. The same power block design was used to the maximum extent practical for both configuration options (except where combustion turbine and auxiliary system arrangement differences dictated changes be made) to maintain the designs as similar as possible. The Site Plans and General Arrangement drawings focused on the following:

- Overall Option 1 Site Plot Plan
- Option 1 General Arrangement
- Overall Option 2 Site Plot Plan
- Option 2 General Arrangement
- Pre-Treatment Water Facility Arrangement
- Water Treatment Building Arrangement

- CT Building Elevation Layout

Considerable review of the existing boiler and turbine buildings were made during the site walkdowns to determine the most cost effective arrangement of the pipe rack from the CT/HRSG's to the existing Steam Turbine. Piping will follow the path of the pipe rack represented on the drawings and will utilize both pipe rack and existing building steel for the support system.

The area selected to the west of existing Unit 1 for the plant will require demolition of the coal conveyor (not currently utilized) and relocation/replacement of other structures as shown on the drawings. Relocation of existing transmission lines will also be required.

The Site Plans and General Arrangement drawings were reviewed in meetings to expedite comments and establish the final design to be used in the costs estimates. The drawings were also updated as required to reflect equipment scope and dimensions as detailed on the proposal drawings received from OEM's during execution of the Combined Cycle Brownfield Build Cost Estimate Study.

The Site Plans and General Arrangement drawings are included in Attachment 1-1.

2.2 Existing System/Equipment Assessment Report

During preparation of the conceptual design existing systems and equipment anticipated to be reused for the repowered configuration options were evaluated for capacity and condition. S&L performed the technical review to insure the system and/or equipment can service the repowered plant in accordance with the design basis. AEP assessed the condition of the existing systems and equipment slated for reuse by reviewing plant maintenance records.

The Equipment Lists document the existing systems and equipment to be reused. The Existing System/Equipment Assessment Reports were created to identify the condition of the systems/equipment to be reused and any repairs/modifications/upgrades required. The Equipment Lists are included in Attachment 1-2 and the Existing System/Equipment Assessment Reports in Attachment 1-3.

2.3 Heat Balances

Primary Heat Balances were prepared for each repowered configuration option to establish sizing criteria for the major equipment. Heat Balances were established for sufficient cases as agreed to with AEP and was based on natural gas fuel and distillate oil fuel firing.

Secondary Heat Balances were prepared after the primary cases were completed for utilization in air permit investigations and for other information deemed necessary for the project. The Secondary Heat Balances were also based on natural gas fuel and distillate oil fuel firing.

The Heat Balance Design Basis and the Heat Balances are included as Attachment 1-4.

2.4 Emissions Calculations

Emissions estimates were prepared for each repowered configuration option based on the heat balances for both natural gas fuel and distillate oil fuel firing. Emissions estimates were calculated for NOx, CO, VOC, SO2, PM/PM10/PM2.5, H2SO4, NH3, and CO2. Maximum emissions and annual averages were calculated.

Emissions Estimates were also prepared for startup and shutdown for each repowered configuration options based on the data received from the OEM's.

The Emissions Calculation Design Basis and the Emission Estimates are included as Attachment 1-5.

2.5 Water Balances

A Water Balance was prepared for the repowered combined cycle plant configuration. The water balance is specific to the repowered combined cycle plant conceptual design and is based on the developed heat balances.

The Water Balance is included as Attachment 1-6.

2.6 Electrical One-Lines

The existing Big Sandy Plant electrical one lines and switchyard one lines in conjunction with the one lines prepared for the Combined Cycle Brownfield Build Cost estimate Study were reviewed to establish the one-lines for the repowered combined cycle plant. A conceptual load list based on in-house data from other projects and proposal information received from the OEM's was prepared. A preliminary Electrical Transient Analysis Program (ETAP) model for the configuration was developed to verify the auxiliary power system design for both repowered configuration options.

The Electrical One-Lines are included as Attachment 1-7.

2.7 Major System P&ID's

P&ID's were prepared for the repowered combined cycle plant major systems to establish the scope of the systems. The P&ID's reflect redundancy requirements and valving requirements for equipment isolation and they also identify the existing equipment and components to be reused. P&ID's were prepared for the following systems:

- Main Steam
- Hot Reheat
- Cold Reheat
- Low Pressure Steam
- Feedwater
- Condensate
- Circulating Water
- Closed Cooling Water
- Fuel Gas
- Fuel Oil

The P&ID's are included as Attachment 1-8.

2.8 DCS Architecture Diagram

A drawing depicting the system architecture of the Distributed Control System (DCS) was developed for the repowered combined cycle plant configuration. The diagram defines the main control room operator and engineer console requirements as well as for other plant facilities.

The repowered combined cycle plant will be controlled from the existing Unit 1 main control room after modifications proposed on the control room arrangement drawing are made.

The DCS Architecture Diagram and the Unit 1 Control Room Layout Drawing is included as Attachment 1-9.

2.9 Reference Studies

The following studies have been performed or are currently ongoing in support of AEP's Big Sandy Unit 1 Repowering Feasibility Study (which was issued final on June 22, 2011) and this Repowering Cost Estimate Study (refer to Section 7.0 for additional information on the reference studies).

2.9.1 Steam Turbine

Mitsubishi Power Systems, Inc. (Mitsubishi) is performing a multiphase evaluation of the existing Steam Turbine for operation in a combined cycle application. The focus of the evaluation is on the repowered steam conditions which vary from the traditional thermal power cycle for which the steam turbine was designed. Mitsubishi initially identified changes to the steam conditions that are required to avoid replacing the last rows of the HP and IP turbines. The Main Steam inlet temperature has been reduced to 950F and the Hot Reheat inlet temperature has reduced to 1000F (accounted for in the heat balances prepared by S&L).

Based on preliminary study results, Mitsubishi is expected to identify additional modifications that are required for the Steam Turbine. These changes are required to balance the thrust loads across the turbine with the new mass flows.

Mitsubishi also identified that the increased mass flow through the LP turbine will require the installation of a new bladepath for the DFLP turbine.

Currently Phase 1, Part 1 and Part 2, and Phase 2, Part 1 studies have been completed and reports issued to AEP. Mitsubishi is expected to issue the remaining Phase 2, Part 2 study report by mid September 2011.

2.9.2 Condenser

SPX was requested to evaluate the existing condenser and was contracted to perform a study. SPX was instructed to (1) review the capability of the condenser to support a 25% increase in exhaust steam flow, (2) evaluate the capability to add steam bypass connections to the existing condenser based on S&L's conceptual design, and (3) evaluate possible performance improvements with new condenser tube bundles.

The results of the SPX study confirmed that the existing tube bundle would need to be staked to prevent vibration with the higher exhaust steam flows and velocities. Modification costs for the staking of the tubes included in the cost estimates cover condenser cleaning, eddy current testing, and staking of the tubes.

SPX also confirmed that the condenser had the capability to add a 1 x 100% CT steam bypass system (the design basis for the project is a 100% steam turbine bypass system). The design basis system would require four connections to the condenser but physical limitations at the condenser limited the space for the installation of the bypass lines. Based on the available space and the SPX review of the condenser capability the current scope of the bypass system includes 2 - 26" Hot Reheat Bypass lines to bypass 100% of the HR steam flow from a single CT/HRSG and 1 - 16" Low Pressure Bypass line to bypass 100% of the LP steam flow from a single CT/HRSG.

SPX recommended the installation of rectangular grating to the top of the tube banks to act as impingement plates protecting the tubes. SPX also recommended regular inspections to determine if steam impingement on the condenser surfaces was causing wear damage.
Performance gains from rebundling the condenser were shown to be possible using new 304 stainless steel, titanium, or 90-10 tubes. Each of the rebundled tube banks would be arranged to optimize the number of tubes installed thereby improving the condenser performance with a lower ST back pressure and less tube side pressure drop on the circulating water system. The changes in the condenser weight and the associated costs of the rebundling have not been evaluated. Costs associated with rebundling the existing condenser are not included in the cost estimates.

Refer to SPX's study report for additional information.

2.9.3 Cooling Tower

The Cooling Tower had been scheduled for film replacement as part of the plant O&M schedule. SPX was contacted by AEP to evaluate performance and cost impacts of various depths for the new fill. The SPX scope of work included in the project cost estimate includes the following items. The resulting improvements in the tower performance have been considered in the preparation of the S&L project heat balances.

- New FRP composite structure.
- New drift eliminator system.
- New distribution system.
- New 7.88' depth of fill.

Refer to SPX's Cooling Tower budgetary proposal for additional information.

3.0 COMMERCIAL BASIS

3.1 Capital Cost Estimate Outline

The Capital Cost Estimates prepared for the Repowered Combined Cycle Plant Configuration Options were organized by Accounts (Areas) and then by Discipline. The cost estimate structure and cost estimate account scope definitions are described in Exhibit 1-5.

3.2 Capital Cost Estimate Accuracy Range

3.2.1 Cost Estimate Classification

The capital cost estimate prepared for the Repowered Combined Cycle Plant Configuration Options were classified in accordance with AACE International Recommended Practice No. 18R-97 dated February 2, 2005 (refer to Exhibit 1-2). As a recommended practice of AACE International, the Cost Estimate Classification System provided guidelines for applying the general principles of estimate classification to project cost estimates.

Based on AACE International Recommended Practice No. 18R-97, the capital cost estimates to be prepared most closely fit the definition of a "Class 3 Estimate" (-10% to -20% and +10% to +30%). A Class 3 cost estimate requires 10% to 40% of full project definition which was exceeded with the conceptual design prepared and the level of line-item detail in the cost estimates. Therefore we claim that the capital cost estimates prepared for Options 1 and 2 have an accuracy of -15% to +20% based on the following:

- Preparation of conceptual design deliverables which formed the basis of the project scope. Review of those conceptual design deliverables with AEP at several Design Review Meetings.
- The preparation of detailed site plans and general arrangement drawings which established plant layout and building sizing.
- Detailed walkdown of Unit 1 to establish interfaces to existing plant equipment and systems that will be reused as part of the repowered plant.
- Use of the Design Basis established for the Combined Cycle Brownfield Build Plant.
- Development of complete heat balances that establish major equipment sizing and review of those heat balances by Mitsubishi.
- The preparation of discipline based calculations to estimate commodity quantities based on the conceptual design.
- The use of conceptual design documents to further prepare commodity quantity estimates that are documented in sketches and other documents (which are included in this study).
- Referencing the major equipment technical specifications previously prepared for the Combined Cycle Brownfield Build Cost Estimate Study which have been reviewed by AEP and used for obtaining pricing for major equipment through a formal RFQ process.
- The use of OEM drawings received from the RFQ process noted above to check against the conceptual design.
- Solicitation of other BOP equipment and system pricing for comparison against historical pricing to establish the cost estimate price.

- The use of labor wage rates that have been verified by AEP and factoring in labor inefficiencies due working 5-10’s.
- Applying escalation factors to the cost estimate based on a project specific schedule.
- Performing a risk analysis on all cost estimate direct accounts to establish a project contingency based on a 95% confidence factor.

3.2.2 Contingency Analysis

The capital cost estimate contingency was determined using the range estimating process and Monte Carlo analysis. The Palisade Corporation @RISK software program was used to perform the risk analysis using Monte Carlo simulation. Range estimating (1) determined the probability of having a cost overrun, (2) identified how large the overrun can be, and (3) identified how much contingency to add to the cost estimate to reduce the residual risk to an acceptable level. Range estimates were determined for each of the cost elements in the cost estimates reflecting the confidence in the cost estimate. Risk drivers include primarily OEM costs, Vendor costs (future market volatility), reuse of existing steam turbine, condenser and cooling tower and the modifications proposed by Mitsubishi and SPX respectively, and accuracy in estimating commodity quantities. Refer to Exhibit 1-6 for the Contingency Analysis summary reports that established the contingency used for both the capital cost estimates and the demolition and removal cost estimates.

3.3 Equipment/Material Cost

Formal Request for Quotation (RFQ) were previously prepared and issued to select OEM’s of major equipment during the Combined Cycle Brownfield Build Cost Estimate Study to obtain proposals for equipment and system pricing. Proposals received in response to the following RFQ’s from that study were referenced in establishing the costs for major equipment and systems for the repowered combined cycle plant:

- BSCC-1: Combustion Turbine Generators
- BSCC-2: Heat Recovery Steam Generators
- BSCC-6: Transformers (MPT, UAT)
- BSCC-7: River Water Pre-Treatment System

- BSCC-8: Water Treatment System
- BSCC-10: Auxiliary Boiler
- BSCC-11: Distributed Control System

3.4 Construction Labor Wages

Union wage rates for the cost estimate were provided by AEP from the TriState Union Wage Rates from Huntington, West Virginia and updated to reflect 90% National Maintenance Agreement (NMA) wage. State specific Workman Comp % Rates were provided by AEP. The craft rates were incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate (See Exhibit 1-3: Union Labor Rate Summary). A 1.10 regional labor productivity multiplier was included based on Compass International Global Construction Yearbook, 2010 Edition plus an additional 5% for planning and execution of a safety program consistent with AEP requirements for a total productivity multiplier of 1.15.

3.4.1 Labor Work Schedule and Incentives

The estimate assumed a 5x10 work week.

A productivity penalty of +8% (in hours) and premium time cost (1-1/2 times the base rate) between the 40 single and 50 single shift was included.

Per-diem subsistence was excluded for craft labor.

3.4.2 Base Craft Rates

The base labor crafts used for the capital cost estimate were defined in the Union Labor Rate Summary found on page 1 of Exhibit 1-3.

3.4.3 Labor Crews

The construction/erection labor cost was based on the use of applicable construction crews required for the scope of work of this project.

3.4.4 Crew Mixes

Major crew mixes used in the cost estimates were defined in the Union Labor Rate Summary found on page 2 of Exhibit 1-3.

3.4.5 Quantity Sources

Quantities of pieces of equipment and/or bulk material commodities used in this cost estimate were intended to be reasonable and representative of projects of this type. Material quantities were estimated from the site plan and general arrangement drawings, various sketches prepared to establish physical design and past project data provided by the S&L Engineers. Equipment quantities were defined in the Equipment Lists and represented on the general arrangements, P&ID's and electrical one-lines. Various sketches and data tables were prepared to further document the commodity quantities used in the cost estimates and are provided in Attachments 1-18 through 1-22.

3.4.6 Construction Indirects

Allowances were included in the cost estimates as direct costs as noted for the following:

- Freight: 5% of the total equipment and material costs. This allowance was excluded for most major equipment since these costs were either included in the OEM proposals or factored in as part of the evaluation process.
- Additional Crane Allowance: All necessary cranes are covered in the wage rates. Additional costs were included for a Tower Crane based upon 18 months of usage with operator.
- Mobilization and Demobilization: included in labor wage rates as 3.52% of total payroll wages + other + construction equipment (refer to Union Labor Rate Summary – Exhibit 1-3)
- Scaffolding: 3% of total material and labor costs.
- Consumables: 0.5% of total material and labor cost
- Loss of Productivity due to working 5-10's for extended periods and Premium Time Pay was included as noted in 3.4.1 above
- Per Diem Costs: Excluded from the estimate as noted in 3.4.1 above.
- Contractor General and Administrative Costs and Profit: Included in the estimate at 15%.

Contractor allowance percentages noted above were base estimating percentages used for this type of major construction project for a study cost estimate. These percentages were applied across the entire estimate and were not intended to be representative of individual estimate work areas.

3.4.7 Engineering/Design/Procurement Services

Sargent & Lundy has included estimated costs for Engineering, Design, Procurement Services and Project Management and Administrative Services. These costs were based upon S&L experience with repowered combined cycle projects and other projects performed for AEP. Costs were also included for field engineering support during construction and start-up/commissioning. In addition costs for Training Services (operator & technician training), and Outside Contractors (site survey, geotechnical investigation, underground utility investigation and noise abatement consultant) were included as separate line items.

3.4.8 Construction Management

Based on AEP's Multi-Prime Contracting Strategy Construction Management costs were excluded since this is an AEP derived cost. AEP will also be responsible for various contracts and service agreements to support construction which are itemized in the Specification List (Attachment 1-16) and itemized as follows:

- Site Services
- Nursing and First Aid Services
- Sanitary Services
- Landscaping Services
- Surveying Services

These costs are accounted for in the cost estimates and included in the site overheads within the labor rates.

3.4.9 Start-Up Commissioning

Based on AEP's Multi-Prime Contracting Strategy Start-up/Commissioning costs were excluded since this is an AEP derived cost. The cost estimate also excludes an allowance for craft support of AEP's start-up/commissioning program. AEP will also be responsible for costs related to steam blow, performance testing and other start-up/commissioning activities and these costs are not accounted for in the cost estimates.

3.4.10 Craft Startup Support

Craft Startup Support was excluded and will be estimated by AEP.

3.4.11 Initial Fills

Initial Fills were estimated at 0.3% of total direct and construction indirect costs.

3.4.12 Spare Parts

Spare parts were included as capitalized spares at 0.9% of total equipment costs and spares for first year of operation at 0.6% of total equipment costs.

3.4.13 Owners Costs

Owner costs were not included and will be provided by AEP for the following:

- Project Engineering
- Project Administration
- Construction Management
- Startup & Commissioning
- Performance Testing
- Fuel, Water, Chemical Costs During Startup/Commissioning
- Permits & Fees
- Air Dispersion Modeling
- Builders All Risk Insurance
- Legal Fees

3.4.14 Sales/Use Tax

Sales/Use Tax was not included in the cost estimate.

3.4.15 Escalation

The following escalation percentages were applied based on input received from AEP.

Equipment: 4.4%/yr of equipment cost (2012-2013).

Material: 6.2%/yr of material cost (2012-2015)

Labor: 2.4%/yr of labor cost (2012-2015)

Indirects: 2.7%/yr of indirect cost (2012-2015).

Escalation was calculated for each component based upon expected equipment delivery and time of performance. The escalation percentages noted above were applied to estimated yearly expenditures for each estimate component; equipment, material, labor and indirects. The yearly expenditures were determined from the cash flow developed. The cash flow was based upon the project schedule developed for this project and estimating curves from past projects and can be found in Exhibit 1-9. The escalation component costs provided was the summation of each of the yearly escalation costs for each component.

3.4.16 Contingency

After completion of the cost estimate a Risk Analysis was performed to develop the contingency to be applied to the cost estimates. Cost categories were defined for establishing target, maximum and minimum values depending on the confidence of achieving the target costs. For each category a range (minimum and maximum values) was determined based on level of design, equipment pricing, material / commodity pricing, labor pricing, and volatility in equipment, material, and labor pricing. These ranges were then entered into a software program utilizing Monte Carlo Simulation to determine an overall contingency for the project. The Monte Carlo Simulation is based on running 10,000 iterations where the inputs are randomly generated from probability distribution curves to simulate the process of sampling. The output was a curve where a point on the curve gives % confidence factor and corresponding overall dollar amount for the project to meet that confidence factor. The software program also provided an output listing contingency % in terms of total direct and indirect costs. For this project a 95% confidence factor was used to determine contingency dollars. Commercially available "@Risk" program was used to perform the risk analysis. Refer to Exhibit 1-6 for the contingency analysis summary.

3.4.17 AFUDC

Costs associated with AFUDC were not included.

3.4.18 Scope Excluded

The following additional scope items were not included.

- Relocation of existing Transmission Line

- Gas Yard and interconnection to the gas supplier
- Interconnection of Transmission Line from power block to the 138kV Switchyard
- City Water interconnection

3.5 ASSUMPTIONS

3.5.1 All utilities such as electricity and water, required for the construction of this project, will be furnished by the owner and made available for use by the installation contractors. The installation contractors will be responsible for construction of the infrastructure needed for utilization of the utility, i.e. construction power distribution system, etc.

3.5.2 All fuel required for construction equipment will be the responsibility of the installation contractors. This cost is part of the rental equipment price included in the crew cost build-up.

3.5.3 Subsequent fills required for testing and startup will be furnished by the owner and include the following:

- Fuel Gas and Oil (if required)
- Service Water
- Demineralized Water for Steam Blows (and disposal of waste)
- Lube Oil, Resins and Grease

3.5.4 Consumables were included as a line item in the estimates totaling 0.5% of Total Direct and Construction Indirect Costs and are comprised of the following:

- Welding Rod
- Solder and Flux
- Tapes of all Types
- Splicing Materials
- Cable-Pulling Compounds
- Sealing Compounds
- Cleaning Fluids

3.5.5 Expendables were included in the crew cost build-up and are comprised of the following:

- Sandpapers
- Emery Cloth
- Rags
- Twine

3.6 Capital Cost Estimates

Refer to the following Exhibits for the detailed capital cost estimates and the summaries:

- Option 1 Detailed Capital Cost Estimate (Attachment 1-10)
- Option 1 Summary Capital Cost Estimate (Attachment 1-12)
- Option 2 Detailed Capital Cost Estimate (Attachment 1-11)
- Option 2 Summary Capital Cost Estimate (Attachment 1-13)
- Fuel Oil Option Detailed Capital Cost Estimate and Summary (Attachment 1-14)
- Base Cost Estimates Takeout Pricing Estimates (Attachment 1-14)

3.7 Capital Cost Estimate Comparison

A cost estimate summary was prepared to compare the repower Option 1 and 2 cost estimates with notes provided to explain the differences. Additional cost estimate comparisons were prepared to compare the repower Option 1 cost estimate to the Combined Cycle Brownfield Build Option 2 cost estimate, and the repower Option 2 (F-Class) cost estimate to the Combined Cycle Brownfield Build F-Class Iteration cost estimate. In addition a comparison was prepared to explain the differences between the original AEP Feasibility Study (for repowering Unit 1) and the repower Option 1 and 2 cost estimates. These summary cost estimate comparisons are provided in Exhibit 1-7.

4.0 O&M COST ESTIMATES

Non-Fuel O&M Cost Estimate were developed for the repowered configuration options based on the heat balances, input provided by AEP and assumptions made by S&L. Total fixed and variable costs were calculated on a yearly basis for the 30 year life of the plant. Levelized (over 30 years) fixed and variable

O&M costs on a $/MWh basis were derived and are summarized in Exhibit 1-8. The detailed O&M Cost Estimate is provided in Attachment 1-15.

5.0 CONTRACTING PLAN

Based on AEP's Multi-Prime Contracting Strategy a Contracting Plan was developed. This plan identifies the procurement scope including all engineered equipment, systems and components required for the project. The plan identifies the various contracting packages required to fit the multi-prime contracting strategy as amended by the schedule time allotted in the project schedule for the engineering/design process. A complete specification list was prepared to identify the various procurement and contracting packages. This list is complemented by the construction contracting plan table which provides additional information on the scope of the fabrication and construction packages and the contract type. Refer to Attachment 1-16 for the Contracting Plan.

6.0 PROJECT SCHEDULE

A Level 1 preliminary project schedule was developed early in the study phase to identify key milestone dates and the latest date Unit 1 can continue to operate to allow sufficient time to complete construction and startup activities for a December 2015 In-Service date. From this schedule a Level 2 Project Schedule was prepared with sufficient detail for the purposes of estimating the cash flow distribution from the cost estimates. One project schedule was developed (for Option 1) that is applicable to both configuration options.

Based on the current anticipated filing date for the Certificate of Convenience and Necessity (CCN) of September 2, 2011 and the 270 days the Kentucky PSC has to act on the CCN filing, the project detailed design start date is set at June 1, 2012. The in-service date for the combined Cycle plant is December 31, 2015. All project activities that need to start prior to the June 1, 2012 date, to achieve the scheduled in-service date, are identified in the schedule.

The Level 1 and 2 Project Schedules are included in Attachment 1-17. The Project Cash Flow is provided in Exhibit 1-9.

7.0 REFERENCES

7.1 AACE International Recommended Practice No. 18R-97 (February 2, 2005): Cost Estimate Classification System – As Applied In Engineering, Procurement, And Construction For The Process Industries. Attached as Exhibit 1-2.

7.2 American Electric Power Big Sandy Unit 1 Final Repowering Study, June 22, 2011 (not attached).

7.3 Sargent & Lundy Combined Cycle Brownfield Build Cost Estimate Study, Summary Report Volume 1, May 31, 2011 (not attached).

7.4 Mitsubishi Power Systems, Inc. Repowering Feasibility Study, Phase 1, Part 1, Thermal Cycle Model, Thrust Evaluation and Mechanical Evaluation, May 20, 2011 (not attached).

7.5 Mitsubishi Power Systems, Inc. Repowering Feasibility Study, Phase 2, Part 1, August 8, 2011 (not attached).

7.6 SPX Cooling Technologies, Inc. Budgetary Proposal for Performing Repairs to Cooling Tower, May 12, 2011 (not attached).

7.7 SPX Cooling Technologies, Inc. Big Sandy Condenser Repowering Evaluation, SC-27576, Revision 0, July 29, 2011 (not attached).