COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

JAN 27 2012

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY)
FOR APPROVAL OF ITS ENVIRONMENTAL)
SURCHARGE PLAN, APPROVAL OF ITS AMENDED)
ENVIORNMENTAL COST RECOVERY) CASE NO. 2011-00401
SURCHARGE TARIFFS, AND FOR THE GRANT OF)
CERTIFICATES OF PUBLIC CONVENIENCE AND)
NECESSITY FOR THE CONSTRUCTION AND)
ACQUISTION OF RELATED FACILITIES)

RESPONSES OF KENTUCKY POWER COMPANY TO COMMISSION STAFF'S INITIAL SET OF DATA REQUESTS

January 27, 2012

VERIFICATION

The undersigned, KARL R. BLETZACKER, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

KARL R. BLETZACKER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 25th day of January 2012.

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

Notary Public

My Commission Expires: October 1, 2016

VERIFICATION

The undersigned, Lila P. Munsey, being duly sworn, deposes and says she is the Manager, Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the forgoing responses for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief

Lila P. Munsey
Lila P. Munsey

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lila P. Munsey, this 20th day of January 2012.

Judy K Rosquist
Notary Public

My Commission Expires: January 23, 2013

VERIFICATION

The undersigned, TOBY THOMAS, being duly sworn, deposes and says he is Managing Director, Kentucky Power Generation, Gas, Renewals and Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief.

TOBY THOMAS

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Toby Thomas, this the 25th day of January 2012.

Notary Public

My Commission Expires: 1/4/2014

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-2014

VERIFICATION

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

ROBERT L. WALTON

STATE OF OHIO)
) CASE NO. 2011-00401
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 20 day of January 2012.

Notary Public

My Commission Expires: 5-29-2012

G. MYERS

VERIFICATION

The undersigned, SCOTT C. WEAVER, being duly sworn, deposes and says he is Managing Director Resource Planning and Operation Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

SCOTT C. WEAVER

STATE OF OHIO)
) CASE NO. 2011-00401
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 24th day of January 2012.

Cheryl L. Strawser
Notary Public

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

My Commission Expires: October 1, 2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that 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)
) CASE NO. 2011-00401
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 20th day of January, 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

VERIFICATION

The undersigned, John M. McManus, being duly sworn, deposes and says he is Vice President Environmental Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

John M. McManus

John M. McManus

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 16 day of January 2012.

Janet L. White

Notary Public

JANET L. WHITE
Notary Public, State of Ohio

My Commission Expires: My Commission Expires 08-08-2013

Kentucky Power Company

REQUEST

Refer to page 3, paragraph 6, of Kentucky Power's Application ("Application"), which discusses its December 2010 notice of termination of the American Electric Power Company ("AEP") Interconnection Agreement ("Pool Agreement").

a. Provide a copy of Kentucky Power's December 2010 notice.

b. Explain whether there are any other agreements to which Kentucky Power is a party that are affected by the termination of the Pool Agreement.

c. If the answer to part b. of this Item is yes, identify the agreements, their terms, and the potential impact to Kentucky Power ratepayers.

d. Explain whether termination notices were given for those agreements. If notice was given, provide a copy of each such notice.

RESPONSE

a. KPCo's notice of termination of the Interconnection Agreement (IA) is shown as attachment 1 of this response.

b. Yes, the AEP System Interim Allowance Agreement (IAA), which is a supplement to the IA, will also be terminated.

c. Please see attachment 2 of this response. The Company continues to evaluate the potential impact.

d. See Article 8 of the IAA which addresses the Terms of the Agreement. There is no explicit notice provision.

WITNESS: Ranie K Wohnhas

AEP
KENTUCKY POWER®
A unit of American Electric Power

Kentucky Power
101A Enterprise Drive
P O Box 5190
Frankfort KY 40602-5190
KentuckyPower.com

December 17, 2010

American Electric Power Service Corporation
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Ohio Power Company
1 Riverside Plaza
Columbus, OH 43215
Attn: President

Re: Interconnection Agreement between Appalachian Power Company, Columbus Southern Power Company, Kentucky Power Company, Indiana Michigan Power Company, Ohio Power Company (collectively, the "Members"), and with American Electric Power Service Corporation as agent ("Agent"), dated July 6, 1951, as amended (the "East Pool Agreement")

NOTICE OF TERMINATION

Dear Sir:

Pursuant to Section 13.2 of the East Pool Agreement, Kentucky Power Company hereby provides notice to the other Members and the Agent to terminate the East Pool Agreement effective as January 1, 2014 or as of such other date that cancellation of the East Pool Agreement is accepted by the Federal Energy Regulatory Commission and becomes effective.

Sincerely,

Gregory G. Pauley
President and Chief Operating Officer
Kentucky Power Company

American Electric Power
1 Riverside Plaza
Columbus OH 43215 2373
614 223 1000
614 223 1667 (Telecopier)

Writer's Direct Dial No

(614) 223-1608

AMERICAN
ELECTRIC
POWER

June 21, 1996

John F. DiLorenzo, Jr.
Vice President, Secretary
and Associate General Counsel

Earl Goldhammer
Tax Counsel

D. Michael Miller
Chief Counsel, Power Generation
and Director of Litigation

John B. Shinnock
Chief Counsel, Energy Delivery

Edward J. Brady
Thomas S. Ashford
Daniel W. Kemp
John M. Adams, Jr.
Assistant General Counsel

Michael R. Luis
Assistant Tax Counsel

Marvin I. Resnik
Kevin F. Duffy
James R. Bacha
Senior Rate Counsel

F. Mitchell Dutton
Rate Counsel

Kenneth E. McDonough
Real Estate Counsel

Kevin D. Mack
Timothy A. King
Barbara A. Belville
Ann B. Graf
Thomas G. Berkemeyer
Senior Attorneys

Jay E. Jadwin
Joseph F. LaFleur
David C. House
Attorneys

Honorable Lois D. Cashell
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20425

Subject: Modification No. 1 to the AEP System Interim Allowance Agreement

Dear Secretary Cashell:

American Electric Power Service Corporation, on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company (collectively "the AEP Companies") tenders to the Commission for filing Modification No. 1 to the AEP System Interim Allowance Agreement.

Included in this filing are an original and six copies of the following documents:

1. This letter of transmittal.

2. Proposed Modification No. 1 to the AEP System Interim Allowance Agreement ("IAA"), which fully integrates the changes being proposed into the IAA.[1]

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[1] The IAA has been designated as Appalachian Power Company Supplement No. 8 to Rate Schedule FERC No. 20; Columbus Southern Power Company, Supplement No. 2 to Rate Schedule FERC No. 30, Indiana Michigan Power Company, Supplement No. 9 to Rate Schedule FERC No. 17; Kentucky Power Company, Supplement No. 5 to Rate Schedule FERC No. 11 and Ohio Power Company, Supplement No. 8 to Rate Schedule FERC No. 23.

3. A document executed by the AEP Companies adopting the changes to the IAA, where deletions appear as struck-through text and additions appear as shaded text.

4. Appendix A, showing the allowance flows and financial statement effects on the AEP Companies for the years 1996 and 1997, of the IAA, as amended. The only change from the existing IAA relates to the intercompany transfers for current year compliance and allocation of the AEP System allowance bank. Under the terms of Modification No. 1 to the IAA, each AEP Company is required to own its MLR-share of the AEP System Allowance Bank at the end of each year. The result of this change is to alter the level of the year-by-year intercompany purchases and sales; however, as shown in Appendix C, there is virtually no effect on the long-term revenue requirements.

5. Appendix B showing the allocation to each AEP Company of (1) the proceeds from EPA emission allowance auctions, (2) the proceeds from emissions allowance sales to third parties, and (3) the cost of allowances purchased from third parties. Under the terms of Modification No. 1 to the IAA, each AEP Company retains the proceeds including carrying charges, associated with the sale of its withheld allowances at EPA emission allowance auctions. Additionally, the proceeds from the sale of other emission allowances to third parties, including carrying charges, are shared on an MLR-basis; and the cost of emission allowances purchased from third parties, including carrying charges, are shared on an MLR-basis.

6. Appendix C showing a comparison of the existing IAA (Base Case) and the Modification No. 1 to the IAA (MLR Case). The results indicate that there is no significant difference in the net present value (NPV) of revenue requirements over a 20-year forecast period.

7. A form of notice suitable for publication in the *Federal Register*.

An additional copy of this letter and all attachments is enclosed which we would appreciate having marked with your file stamp, docket number, and date and returned in the enclosed self-addressed, postage-paid envelope.

Background of Filing

In September 1994, the AEP Companies filed the IAA with the Commission. The purpose of the IAA was to establish, on an interim basis, a methodology and price for the transfer of emission allowances among the major operating companies of the

American Electric Power ("AEP") System, a multistate public utility holding company system registered under the Public Utility Holding Company Act of 1935.

In developing the IAA, the AEP Companies worked in close cooperation with the AEP Regional Coordinating Committee, a committee consisting of representatives and/or staff from each of the seven state regulatory commissions that oversee the utility operations of the AEP operating companies. The IAA represented a compromise position designed to resolve differences of opinion among the state regulators regarding the distribution among the AEP operating companies of costs and benefits associated with the Companies' compliance with the Clean Air Act Amendments of 1990.

The IAA provides for and governs the terms of five basic types of allowance transactions among the AEP Companies: (1) an annual reallocation of allowances initially allocated by the United States Environmental Protection Agency to Ohio Power's Gavin Plant; (2) transfer of allowances associated with primary and economy energy transactions among the members; (3) a monthly cash settlement for allowances consumed in connection with power sales to foreign (i.e., non-affiliated) companies; (4) transfers of allowances for current period compliance; and (5) transfers of allowances for future period compliance.

The IAA was accepted for filing by the Commission by letter order of December 30, 1994 in Docket No. ER94-1670-000.

An issue that was unresolved by the IAA was the allocation of costs and revenues related to the sale or purchase of allowances to or from non-affiliated companies. The IAA states that this issue is intended to be addressed in a subsequent agreement governing all such transactions whether occurring before or after the effective date of such agreement. The IAA further provides that during the interim period pending resolution of the issue, the net proceeds from such transactions shall be deferred, with a return at the AEP System cost of capital, on the books of the Member involved (IAA, § 2.2).

Following the Commission's acceptance of the IAA, AEP representatives continued their contacts with the Regional Coordinating Committee and the individual state commissions that are members of the Regional Coordinating Committee, in an effort to resolve the unresolved issue regarding the treatment of costs and proceeds associated with sales of allowances to non-affiliates. Modification No. 1 reflects a resolution of this issue which the AEP Companies believe is satisfactory to each of the state regulatory commissions involved.[2] In addition, Modification No. 1 effects certain changes designed to simplify administration of the agreement and to support the reasonableness of the proposed treatment of allowance proceeds.

Explanation of Amendments

Modification No. 1 to the IAA makes the following changes to the agreement:

1. Each Member would be required to own its Member Load Ratio ("MLR") share of the AEP System allowance bank at the end of each year. MLR is a measure of relative peak demand extensively used in the AEP System Interconnection Agreement, Transmission Agreement and IAA for allocation of costs and benefits among the members. Under the IAA as originally filed, each Member was required to own at the end of the year, a portion of the bank based on an estimate of its needs for future compliance and a share of a "Contingency Bank" based on its original EPA allocation of allowances. By simply requiring each member to own an MLR share of the total system bank, the proposed amendments simplify the administration of the agreement by eliminating the need to estimate each Member's future compliance needs. In addition, MLR sharing of the System bank is consistent with the proposed MLR sharing of costs and revenues associated with sales of allowances to non-affiliates.

2. Each member would pay for and receive its MLR share of any allowances purchased from third parties, including any allowances purchased at EPA auctions held pursuant to Section 416 of the 1990 Clean Air Act Amendments, 42 U.S.C. § 7651o.

3. Each Member would contribute its MLR share of allowances toward any sale to third parties and would receive its MLR share of the proceeds from any such sales.

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[2] At least one state regulatory commission prefers to retain the designation of the IAA as an interim agreement, in recognition of the fact that the IAA continues to reflect a compromise that may not be ideal from the standpoint of each individual state. However, Modification No. 1 resolves the major outstanding issue left unresolved by the IAA, and the AEP Companies do not expect any substantive protest of Modification No. 1 or any other provision of the IAA by any of the state commissions.

4. Each member would share in the net proceeds and costs, and accrued carrying charges on such proceeds and costs associated with allowance transactions with non-affiliates which occurred prior to the effective date of Modification No. 1.

5. Each Member would retain the proceeds associated with the sale of its withheld allowances at the EPA auctions.

In addition, to simplify the administration of the provision related to allowances consumed in connection to sales to foreign companies, reimbursement to the supplying member pursuant to Section 4.3 of the IAA would be made at average inventory cost instead of the cost of compliance.

Effect of Modification No. 1 to IAA

Appendices A, B and C, described above, show the allowance flows and financial effects on the Members for the years 1996 and 1997, the allocations to each Member, and a net present value comparison of revenue requirements, respectively, compared to the same effects under the IAA prior to the proposed amendments.

Effective Date

The AEP Companies request an effective date of September 1, 1996. However, in accordance with original Section 2.2 of the IAA, transactions with non-affiliates which have occurred prior to the effective date will be processed as though this Modification No. 1 had been in effect.

Pre-Filing Communications With State Commissions, Wholesale Customers and FERC Staff

As indicated above, the AEP Companies have worked with the Regional Coordinating Committee and individual state commissions in developing proposed Modification No. 1 to the IAA. It is our understanding and belief that none of the state commissions will object to the proposed modification. In addition, we have, through meetings and other communications, explained the substance, development and effect of proposed Modification No. 1 to our wholesale customers. Finally, the AEP Companies, in advance of the filing, sought guidance from the Commission's Division of Applications regarding the Division's informational needs in connection with the filing.

Service and Notices

Copies of this filing have been served upon the Indiana Regulatory Utility Commission, The Kentucky Public Service Commission, The Michigan Public Service Commission, The Public Utilities Commission of Ohio, The Public Service Commission of West Virginia, the Public Service Commission of Tennessee and the Virginia State Corporation Commission.

Communications regarding this matter should be sent to the following:

Henry W. Fayne
Senior Vice President
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 223-2890

Edward J. Brady, Esq
Kevin F. Duffy, Esq.
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 223-1608

Request for Effective Date and Waivers

The AEP Companies request an effective date of September 1, 1996.

The AEP Companies request that the IAA be allowed to go into effect without suspension, hearing or investigation. Such action is appropriate in light of the extensive prefiling involvement of state regulators and communications with wholesale customers, FERC Staff and other interested parties. The AEP Companies have accumulated proceeds associated with sales of allowances to non-affiliates. Upon approval of Modification No. 1 to the IAA, the AEP Companies will be able to determine that portion of the proceeds to be allocated to each Member of the AEP System. Once this determination is made on a system basis, each state jurisdiction can address the retail aspects of these transactions. The AEP Companies request waiver of any regulations with which this filing may not comply, in order that it may be allowed to go into effect on August 15, 1996 as requested and the Companies' customers may benefit from these transactions.

Respectfully submitted,

Edward J. Brady
Kevin F. Duffy
Attorneys for the AEP Companies

Public Service Commission
of West Virginia
State Capitol Building
Charleston, WV 25305

Tennessee Public Service Commission
460 James Robertson Parkway
Nashville, TN 37243-0505

Kentucky Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40602

Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

Indiana Utility Regulatory Commission
Indiana Government Center South
302 West Washington Street, E306
Indianapolis, IN 46204

State Corporation Commission
Document Control Center
Jefferson Bldg., Level B1
1220 Bank St.
Richmond, VA 23219

Public Utilities Commission of Ohio
Docketing Division
180 East Broad Street
Columbus, Ohio 43215

MODIFICATION NO. 1 TO THE
AEP SYSTEM INTERIM ALLOWANCE AGREEMENT

BY AND AMONG

APPALACHIAN POWER COMPANY

COLUMBUS SOUTHERN POWER COMPANY

INDIANA MICHIGAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

AND WITH

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AS AGENT

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 28th day of July, 1994 by and among APPALACHIAN POWER COMPANY (APCo), a Virginia corporation, COLUMBUS SOUTHERN POWER COMPANY (CSP), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (I&M), an Indiana corporation, KENTUCKY POWER COMPANY (KPCo), a Kentucky corporation, OHIO POWER COMPANY (OPCo), an Ohio corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power System (AEP), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and the other affiliated companies.

WITNESSETH

THAT:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated, (i) APCo in Virginia, West Virginia and Tennessee, (ii) CSP in Ohio, (iii) I&M in Indiana and Michigan, (iv) KPCo in Kentucky, and (v) OPCo in Ohio and West Virginia; and

0.3 WHEREAS, the Members have entered into an Interconnection Agreement, dated July 6, 1951, with modifications thereto, which provides for certain understandings, conditions, and procedures designed to achieve the full benefits and advantages available through the coordinated planning and operation of their electric power supply facilities; and

0.4 WHEREAS, Congress in 1990 enacted amendments to the Clean Air Act, including Title IV, 104 Stat. 2584, 42 U.S.C.A. § 7651, et seq. ("the 1990 Amendments") which limit emissions of sulfur dioxide (SO_2) by electric utilities; and

0.5 WHEREAS, under the 1990 Amendments, compliance is to be achieved in two stages -- Phase I, which begins January 1, 1995 and Phase II which begins January 1, 2000; and reductions in sulfur dioxide emissions are to be effected by a system in which a limited number of "emission allowances" have been allocated by the United States Environmental Protection Agency (EPA) to individual utility generating units; and

0.6 WHEREAS, twenty-one (21) of the Members' generating units have been designated by the 1990 Amendments as Phase I affected units, and fifty-one (51) of the Members' generating units have been designated as Phase II affected units, and as such, have been awarded emission allowances by the EPA; and

0.7 WHEREAS, the Members may have ownership or entitlement to emission allowances through several means, including: (i) EPA-AWARDED ALLOWANCES based on emission levels experienced during a base-line period, (ii) EPA bonus allowances awarded for various compliance strategies, primarily through the installation of FGD systems, and (iii) the purchase of allowances. Generally, Members are permitted to emit SO_2 only to the extent they have allowances to cover such emissions.

0.8 WHEREAS, compliance with the 1990 Amendments has been and will continue to be planned by the Members on an integrated and coordinated basis, consistent with the integrated and coordinated planning and operation of the Members' electric systems; and

0.9 WHEREAS, the Members desire to arrive at an equitable methodology of allocating emission allowances and associated costs and benefits between and among the Members; and

0.10 WHEREAS, the Members have entered into the Interim Allowance Agreement to establish, on an interim basis, a methodology and transfer price for the transfer of SO_2 emission allowances; and

0.11 WHEREAS, the Members believe that an agreement which provides for an equitable assignment of cost and benefits among the Members can best be realized if administered by a single clearing agent; and

0.12 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services;

0.13 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto, hereby agree as follows:

ARTICLE 1

DEFINITIONS

1.1 The following terms and factors associated with settlements under this Agreement are defined in alphabetic order as follows:

1.2 DELIVERING MEMBER -- a Member which sells PRIMARY ENERGY and/or ECONOMY ENERGY to the POOL.

1.3 ECONOMY ENERGY -- electric energy delivered to the POOL from the MEMBER PRIMARY CAPACITY of a particular Member to displace energy that otherwise would be supplied by less efficient MEMBER PRIMARY CAPACITY of another Member to meet its MEMBER LOAD OBLIGATION.

1.4 EPA-AWARDED ALLOWANCES -- the allowances awarded to each generating unit by the EPA as defined in Section 404(a) of the 1990 Amendments.

1.5 FERC -- the Federal Energy Regulatory Commission or any successor agency.

1.6 GAVIN BONUS ALLOWANCES -- 184.7, 184.0, 44.6, 44.6 and 44.6 thousand allowances, excluding transfer allowances, for the years 1995, 1996, 1997, 1998 and 1999, respectively, awarded by the EPA to OPCo's Gavin Plant pursuant to Section 404(d) of the 1990 Amendments.

1.7 GAVIN EPA-AWARDED ALLOWANCES -- the allowances awarded to the Gavin Plant by the EPA pursuant to Section 404(a) of the 1990 Amendments.

1.8 GAVIN SCRUBBER SO_2 REDUCTION -- the difference between actual SO_2 emissions at OPCo's Gavin Plant operating with scrubbers and GAVIN UNCONTROLLED EMISSIONS for a given year.

1.9 GAVIN UNCONTROLLED EMISSIONS -- an estimated amount of SO_2 emissions that would result from operating the Gavin Plant without scrubbers. The estimate of GAVIN UNCONTROLLED EMISSIONS is calculated by dividing the scrubbed Gavin SO_2 EMISSIONS by (1.00 minus the scrubber SO_2 removal efficiency rate).

1.10 INTERCONNECTION AGREEMENT -- the Interconnection Agreement among the Members dated July 6, 1951, as amended.

1.11 MEMBER AFFECTED UNITS -- a Member's generating units that are required to meet the emission standards established by the 1990 Amendments.

1.12 MEMBER CAPACITY DEFICIT FACTOR -- for any Member, the average for the calendar year of its MEMBER PRIMARY CAPACITY DEFICIT divided by the sum of all members' average MEMBER PRIMARY CAPACITY DEFICITS.

1.13 MEMBER DEMAND -- MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

1.14 MEMBER GENERATION -- the total of a Member's net generation from its MEMBER PRIMARY CAPACITY.

1.15 MEMBER LOAD OBLIGATION -- a Member's internal load plus any firm power sales to Foreign Companies and to affiliated companies other than Members.

1.16 MEMBER LOAD RATIO -- the ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the five MEMBER MAXIMUM DEMANDS in effect for such month.

1.17 MEMBER MAXIMUM DEMAND -- the MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by said Member during the twelve consecutive calendar months next preceding such calendar month.

1.18 MEMBER PRIMARY CAPACITY -- the aggregate capacity of the electric power sources of a particular Member, in kilowatts, that is normally expected to be available to carry load. Such capacity shall include (i) the capacity installed at the generating stations owned by the Member and (ii) the capacity available to that Member through interconnection arrangements with affiliated companies or Foreign Companies.

1.19 MEMBER PRIMARY CAPACITY DEFICIT -- difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY is less than such MEMBER PRIMARY CAPACITY RESERVATION.

1.20 MEMBER PRIMARY CAPACITY RESERVATION -- SYSTEM PRIMARY CAPACITY multiplied by the MEMBER LOAD RATIO of a particular Member.

1.21 OPCo CAPACITY SURPLUS FACTOR -- the weighted average for the calendar year of (OPCo's MEMBER PRIMARY CAPACITY minus OPCo's MEMBER PRIMARY CAPACITY RESERVATION) divided by OPCo's MEMBER PRIMARY CAPACITY.

1.22 OVER-COMPLIANCE -- the amount by which a Member's SO_2 EMISSIONS are less than its EPA-AWARDED ALLOWANCES for the current year; provided, however, that in determining OPCo's OVER-COMPLIANCE, its emissions shall be deemed to include, in lieu of actual emissions from the Gavin Plant, 50% of GAVIN UNCONTROLLED EMISSIONS, and its allowances shall be deemed to include, in lieu of actual GAVIN EPA-AWARDED ALLOWANCES, only 50% of GAVIN EPA-AWARDED ALLOWANCES.

1.23 POOL -- electric energy delivered by one Member, from its MEMBER PRIMARY CAPACITY, to another Member shall be considered to be energy delivered to the POOL by the former Member and delivered from the POOL by the latter Member.

1.24 POWER SALES TO FOREIGN COMPANIES -- sales of electric power and energy to Foreign Companies, made by a Member on behalf of the System, where the revenue and cost of such sales are allocated to the Members in proportion to their respective MEMBER LOAD RATIOS.

1.25 PRIMARY AND ECONOMY ENERGY RECEIPT FACTOR -- the ratio of PRIMARY ENERGY and ECONOMY ENERGY receipts by a receiving Member from a DELIVERING MEMBER to the total sales of PRIMARY ENERGY and ECONOMY ENERGY by the DELIVERING MEMBER.

1.26 PRIMARY AND ECONOMY ENERGY SUPPLY FACTOR -- the sum of the Member's PRIMARY ENERGY and ECONOMY ENERGY deliveries divided by the MEMBER'S GENERATION.

1.27 PRIMARY ENERGY -- electric energy delivered to the POOL from the MEMBER PRIMARY CAPACITY of a particular Member to meet another Member's deficiency in capacity.

1.28 RECEIVING MEMBER -- a Member which buys PRIMARY ENERGY and/or ECONOMY ENERGY from the POOL.

1.29 SO_2 EMISSIONS -- the total of the Member's SO_2 EMISSIONS from the MEMBER'S AFFECTED UNITS.

1.30 SURPLUS ALLOWANCES -- the excess of a Member's current year EPA-AWARDED ALLOWANCES, plus allowances transferred to the Member pursuant to Sections 4.1, 4.2, 4.3 and 4.4 of this Agreement, over the Member's annual SO_2 EMISSIONS and its MLR share of the SYSTEM ALLOWANCE BANK.

1.31 SYSTEM ALLOWANCE BANK -- the sum of all the Members' allowances in excess of all the Members' SO_2 emissions.

1.32 SYSTEM COST OF COMPLIANCE -- for calendar year 1995 is $115.43/ton of SO_2. For each subsequent year, the SYSTEM COST OF COMPLIANCE shall be $115.43/ton of SO_2 escalated annually at a rate of 10.56%.

1.33 SYSTEM PRIMARY CAPACITY -- the sum of the MEMBER PRIMARY CAPACITY of all the Members.

1.34 UNDER-COMPLIANCE -- the amount by which a Member's SO_2 EMISSIONS are greater than its EPA-AWARDED ALLOWANCES for the current year; provided, however, that in determining OPCo's UNDER-COMPLIANCE, its emissions shall be deemed to include, in lieu of actual emissions from the Gavin Plant, 50% of GAVIN UNCONTROLLED EMISSIONS, and its allowances shall be deemed to include, in lieu of actual GAVIN EPA-AWARDED ALLOWANCES, only 50% of GAVIN EPA-AWARDED ALLOWANCES.

ARTICLE 2

EMISSION ALLOWANCE MANAGEMENT

2.1 In determining the transfer of costs and benefits related to emission allowances among Members, settlements for the following transactions will be governed by this Agreement: 1) an annual reallocation of Gavin allowances, described in Section 4.1, 2) an annual cash settlement for the transfer of allowances associated with PRIMARY ENERGY and ECONOMY ENERGY, described in Section 4.2, 3) a monthly cash settlement for allowances consumed for POWER SALES TO FOREIGN COMPANIES, described in Section 4.3, 4) sales and purchases of allowances to/from non-affiliated parties, described in Section 4.4, and 5) an annual transfer of allowances for current period compliance and allocation of the SYSTEM ALLOWANCE BANK, described in Section 4.5.

2.2 Agent shall have the authority to make any and all decisions relating to the use, management, purchase, sale and transfer of emission allowances. Except as provided in this Agreement or any superseding agreement, no other payment or compensation shall be made between or among the Members with respect to any such use, management, purchase, sale or transfer.

ARTICLE 3

AGENT'S RESPONSIBILITIES

3.1 For the purpose of carrying out the provisions of this Agreement, the Members hereby delegate to Agent, and Agent hereby accepts, the responsibility of administration of this Agreement, and in furtherance thereof Agent hereby agrees:

3.11 To render to each Member as promptly as possible after the end of each month a statement setting forth the settlements hereunder for such preceding calendar month, in such detail and with such segregation as may be needed for accounting, operating, or other proper purposes.

3.12 To carry out allowance transfer settlements under this Agreement. Settlement for the Gavin Allowance Reallocation shall be recorded annually in December for each calendar year.

3.13 To carry out cash settlements under this Agreement through an account (hereby designated and hereinafter called the SYSTEM ALLOWANCE ACCOUNT) to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total amount of the payments made by the Members to the SYSTEM ALLOWANCE ACCOUNT each month shall be equal to the total amount of the payments made from the SYSTEM ALLOWANCE ACCOUNT for the same period.

3.131 Monthly settlements by the Members shall be determined for Allowances Consumed for Power Sales to Foreign Companies.

3.132 Annual settlements by the Members shall be determined in December of each calendar year for Allowance Transfers for Primary and Economy Energy Transactions.

3.133 Settlements by the Members shall be determined for allowances sold and purchased to/from non-affiliated parties as they occur.

3.134 Annual settlements by the Members shall be determined in December of each calendar year for the Transfer of Allowances for Current Period Compliance and Allocation of the System Allowance Bank.

ARTICLE 4

SETTLEMENTS

4.1 GAVIN ALLOWANCE REALLOCATION - In December of 1995 and each subsequent calendar year, the allowance inventory accounts of the Members will be adjusted to recognize the Gavin Allowance Reallocation. The number of Gavin allowances available for reallocation is determined by multiplying the OPCo CAPACITY SURPLUS FACTOR by the sum of (i) GAVIN BONUS ALLOWANCES and (ii) 50% of the sum of the GAVIN EPA-AWARDED ALLOWANCES and the GAVIN SCRUBBER SO_2 REDUCTION. The Gavin allowances available for reallocation shall be transferred, at zero cost, to the Members having a MEMBER

PRIMARY CAPACITY DEFICIT. Each deficit Member's share of the Gavin Allowance Reallocation is determined by multiplying the Gavin Allowances to Reallocate by the MEMBER'S CAPACITY DEFICIT FACTOR.

4.2 ALLOWANCE TRANSFERS ASSOCIATED WITH PRIMARY AND ECONOMY ENERGY TRANSACTIONS - In December of each year, the DELIVERING MEMBERS shall transfer allowances to or receive allowances from the RECEIVING MEMBERS, according to this Section. A DELIVERING MEMBER shall be transferred allowances from a RECEIVING MEMBER if the DELIVERING MEMBER is in an UNDER-COMPLIANCE position. A DELIVERING MEMBER shall transfer allowances to a RECEIVING MEMBER if the DELIVERING MEMBER is in an OVER-COMPLIANCE position. Members supplying allowances shall be compensated by the Members receiving allowances based on the supplying Member's average allowance inventory cost. For the year, a Member may be both a DELIVERING MEMBER and a RECEIVING MEMBER.

4.21 In December of each year, the Member's annual OVER-COMPLIANCE or UNDER-COMPLIANCE shall be determined.

4.22 The PRIMARY AND ECONOMY ENERGY SUPPLY FACTOR of each DELIVERING MEMBER shall be multiplied by that Member's over/(under) compliance to determine its incremental OVER-COMPLIANCE or incremental UNDER-COMPLIANCE position. The incremental over/(under) compliance position represents the total number of allowances to be transferred from or received by the DELIVERING MEMBER.

4.23 If the DELIVERING MEMBER is in an UNDER-COMPLIANCE position, the number of allowances to be transferred from the RECEIVING MEMBER is calculated by multiplying the DELIVERING MEMBER'S incremental UNDER-COMPLIANCE by the respective PRIMARY AND ECONOMY ENERGY RECEIPT FACTOR. If the DELIVERING MEMBER is in an OVER-COMPLIANCE position, the number of allowances to be transferred to the RECEIVING MEMBERS is calculated by multiplying the incremental OVER-COMPLIANCE of the DELIVERING MEMBER by the respective PRIMARY AND ECONOMY ENERGY RECEIPT FACTORS.

4.24 The net allowances transferred from the supplying Member during the year are priced at their individual weighted average inventory cost computed at the end of December. The net allowances transferred to the receiving Members shall be based on the weighted average inventory cost of all Members supplying allowances. The average inventory cost of a supplying Member is computed by taking the total book cost of allowances available for transfer divided by the number of allowances available for transfer at the end of December.

4.3 ALLOWANCES CONSUMED FOR POWER SALES TO FOREIGN COMPANIES - When allowances are consumed for power sales to foreign companies, the customer has the option of reimbursing the supplying company with allowances in kind, or paying cash for the allowances at the current market rate. If the customer reimburses in kind, the allowances shall be retained by the supplying Member (Member company that generated the energy and consumed the allowances); and a cash settlement shall be made to each Member based on its MLR-share of the current value of the allowances received. If cash is received, in lieu of allowances, it shall be shared by each member based on its current MLR. The supplying Member's consumed cost of allowances for sale to foreign companies shall be allocated to each Member based on its current MLR. The method for determining the allowances consumed in generating the energy for POWER SALES TO FOREIGN COMPANIES is set forth in Appendix E to this Agreement.

4.4 ALLOWANCE TRANSACTIONS WITH NON-AFFILIATED PARTIES - Participation in the allowance market could involve either the sale or purchase of allowances to or from non-affiliated parties.

4.41 SALE OF ALLOWANCES - Except as provided in Section 4.43, in the event allowances are sold to non-affiliated parties, each Member shall contribute its MLR share of the total quantity sold. To the extent a Member cannot provide its MLR share due to a shortfall, that Member shall purchase an amount of allowances necessary to cover the shortfall from other Members having a surplus, at the System Cost of Compliance. Each Member shall receive its MLR share of the total proceeds.

4.42 PURCHASE OF ALLOWANCES - In the event allowances are purchased from non-affiliated parties, each Member shall take ownership of its MLR share of the total quantity purchased and pay its MLR share of the total cost.

4.43 SALE OF WITHHELD ALLOWANCES AT EPA AUCTIONS - The proceeds from sales of allowances withheld by the EPA, pursuant to Section 416 of Title IV of the 1990 Amendments, shall be retained by the Member owning the generating units from which the allowances were withheld.

4.44 NET PROCEEDS AND COSTS FROM PREVIOUS ALLOWANCE TRANSACTIONS - The net proceeds from sales of allowances to non-affiliated parties which occurred prior to the effective date of Modification No. 1 to this Agreement, the cost of allowances purchased from non-affiliated parties which occurred prior to the effective date of Modification No. 1 to this Agreement and all carrying charges accrued on such proceeds and costs, shall be shared by each Member based on its MLR.

4.5 TRANSFERS OF ALLOWANCES FOR CURRENT PERIOD COMPLIANCE AND ALLOCATION OF THE SYSTEM ALLOWANCE BANK - At the end of December of each calendar year, each Member shall own a share of the SYSTEM ALLOWANCE BANK, based on its current MEMBER LOAD RATIO. A Member whose annual SO_2 EMISSIONS exceed its available allowance inventory, after intercompany settlements described in Section 4.1, 4.2, 4.3 and 4.4 of this Agreement, will purchase allowances to eliminate its shortfall in that calendar year and to provide for its MLR share of the SYSTEM ALLOWANCE BANK. These purchases will be made from Members having SURPLUS ALLOWANCES and will be priced at the SYSTEM COST OF COMPLIANCE. If more than one Member has SURPLUS ALLOWANCES, the buying Member will purchase a proportionate share from the surplus Members.

ARTICLE 5

BILLINGS AND PAYMENTS

5.1 All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month to which a settlement has been rendered, or on the tenth day following the receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon, the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of this Agreement.

ARTICLE 6

TAXES

6.1 If at any time during the duration of this Agreement there should be levied and/or assessed by any governmental authority against any Member any tax related to the receipt of settlements calculated pursuant to Article 5 of this Agreement (including, but not limited to sales, excise, etc.), the tax expense incurred by such Member that would not have been incurred were the allowance settlements hereunder not being made, such Member shall be entitled to reimbursement of the tax expense from the Member generating the tax expense.

ARTICLE 7

MODIFICATIONS

7.1 Any Member, by written notice given to the other Members and Agent, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, the Members shall take into account any changed conditions, any results from the application of said terms and conditions, and any other facts that might cause said terms and conditions to result in an inequitable sharing of costs and benefits under this Agreement. Any modification in terms and conditions agreed to by the Members shall be subject to appropriate regulatory approval and become effective the first day of the month following regulatory authorization.

ARTICLE 8

EFFECTIVE DATE AND TERMS OF THIS AGREEMENT

8.1 This Agreement shall become effective and shall become a binding obligation of the Parties on January 1, 1995, or such other effective date determined by FERC.

8.2 This Agreement shall continue in effect from the effective date until the effective date of any subsequent agreement.

ARTICLE 9

REGULATORY AUTHORITIES

9.1 The Members recognize that this Agreement, and any tariff or rate schedule which shall embody or supersede this Agreement or any part thereof, are in certain respects subject to the jurisdiction of the FERC under the Federal Power Act, and are also subject to such lawful action as any regulatory authority having jurisdiction shall hereinafter take with respect thereto. The performance of any obligation of the Members shall be subject to the receipt of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

9.2 It is expressly understood that the Members shall be entitled, at any time unilaterally, to make application to the FERC for a change in the rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of the this Agreement, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

ARTICLE 10

ASSIGNMENT

10.1 This Agreement shall accrue to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties hereto have caused the Agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto duly authorized as of the day and year first above written.

APPALACHIAN POWER COMPANY

By (Signature on Original Document)

COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY

By (Signature on Original Document)

INDIANA MICHIGAN POWER COMPANY

By (Signature on Original Document)

KENTUCKY POWER COMPANY

By (Signature on Original Document)

AMERICAN ELECTRIC POWER
SERVICE CORPORATION

By (Signature on Original Document)

WHEREAS, APPALACHIAN POWER COMPANY (APCO), a Virginia corporation, COLUMBUS SOUTHERN POWER COMPANY (CSP), an Ohio corporation, INDIANA MICHIGAN POWER COMPANY (I&M), an Indiana corporation, KENTUCKY POWER COMPANY (KPCO), a Kentucky corporation, OHIO POWER COMPANY (OPCO), an Ohio corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually) being affiliated companies of the integrated public utility electric system known as the American Electric Power System (AEP), and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and the other affiliated companies, all of whom are currently doing business as American Electric Power, desire to establish a mechanism for the allocation of emission allowance costs and proceeds associated with purchases and sales with non-affiliated entities; and

WHEREAS, the Members desire to amend the AEP System Interim Allowance Agreement dated July 28, 1994 to reflect this mechanism and to effect certain other changes to the Agreement; and

WHEREAS, except as changed by amendments, the AEP System Interim Allowance Agreement remains in full force and effect.

NOW THEREFORE, the Members adopt the document attached hereto showing the proposed amendments to the AEP System Interim Allowance Agreement in a form in which deletions appear as struck-through text and additions appear as shaded text, as "Modification No. 1 to the AEP System Interim Allowance Agreement By and Among

Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company and With American Electric Power Service Corporation As Agent."

Agreed to this ___ day of June, 1996.

Wm J Lhota

By: William J. Lhota

Title: President and Chief Operating Officer of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company; and Executive Vice President of American Electric Power Service Corporation, collectively doing business as American Electric Power

APPENDIX A

ALLOWANCE TRANSFER SUMMARY

FINANCIAL STATEMENT EFFECTS

AEP System
Interim Allowance Agreement - Modification No. 1
Description of Allowance Transfer Summary

The forecasted allowance transfers for 1996 and 1997, pursuant to Modification No. 1 of the Interim Allowance Agreement, are summarized on the top of Pages 3 and 4 of Appendix A. Under the terms of Modification No. 1 ("Modified Agreement"), the calculation of these transfers remains unchanged, with the exception of the Intercompany Purchases/(Sales). The elements related to the allowance transfers are described below.

EPA Awarded Allowances - Defined in Section 1.4 of the Modified Agreement, EPA Awarded Allowances represent the allowances awarded to each generating unit by the EPA as defined in Section 404(a) of the 1990 Amendments.

Other Allowances, Ormet - Other Allowances represent the allowances received by OPCO from Ormet Primary Aluminum Corporation, pursuant to a contract for retail power sales to Ormet.

SO2 Emissions - Defined in Section 1.29 of the Modified Agreement, SO2 Emissions represent the total of the Member's SO2 Emissions from the Member's Affected Units.

Over/(Under) Compliance - Represents the difference between a Member's allowances (including EPA Awarded Allowances and Other Allowances) and its SO2 Emissions.

Gavin Reallocation - Described in Section 4.1 of the Modified Agreement, the terms of the Gavin Reallocation are not affected by Modification No. 1.

P&E Transfers - Described in Section 4.2 of the Modified Agreement, the terms of the P&E Transfers are not affected by Modification No. 1.

Intercompany Purchases/(Sales) - Described in Section 4.5 of the Modified Agreement, the method for calculating Intercompany Purchases/(Sales) of allowances has been changed by Modification No. 1. Under the amended terms, each Member must own, at the end of each calender year, a sufficient number of allowances to cover (1) its annual compliance requirement and (2) its MLR-share of the AEP System Allowance Bank. This represents a change from the original agreement, which required each Member to own, at the end of each calender year, a sufficient number of allowances to cover (1) its annual compliance requirement and (2) a share of the AEP System Allowance Bank based on its estimated future compliance requirements over a 20-year forecast period. The calculation of Intercompany Purchases/(Sales) is presented on Pages 5 and 6 of Appendix A.

AEP System
Interim Allowance Agreement - Modification 1
Description of Financial Statement Effects

The forecasted financial statement effects of allowance transfers for 1996 and 1997, pursuant to Modification 1 of the Interim Allowance Agreement, are summarized on the bottom of Pages 1 and 2 of Appendix A. Below is a brief description the effects on financial statements.

Income Statement Effects:

Sales for Resale - Reflects the reimbursement of the market value of allowances consumed for sales to foreign companies. Also reflects intercompany billing for the consumed cost of such allowances.

Purchased Power - Reflects the consumed cost of allowances used in the generation for sales to foreign companies.

SO2 Emissions Expense - Reflects the consumption of allowances, at average cost, to cover the SO2 emissions from affected units.

Balance Sheet Effects:

Allowance Inventory - Reflects increases in the value of Allowance Inventory due to (1) P&E Transfers In and (2) Intercompany Purchases. Reflects decreases in the value of Allowance Inventory due to (1) P&E Transfers Out, (2) Intercompany Sales and (3) SO2 Emissions.

Accounts Receivable/Payable - Reflects receivables/payables associated with (1) Intercompany Allowance Purchases/Sales, (2) P&E Transfers and (3) settlements for allowances consumed for sales to foreign companies.

Other Regulatory Liabilities - Represents the deferred gain from allowance sales to other Members.

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT
MODIFICATION No. 1
1996 FORECAST

	APCO	CSP	I&M	KYPC	OPCO	SYSTEM
Allowance Transfer Summary (Tons)						
EPA Awarded Allowances	-	101,444	47,489	-	757,340	906,273
Other Allowances - Ormet	-	-	-	-	66,400	66,400
SO2 Emissions	-	(87,800)	(32,200)	-	(343,000)	(463,000)
Over/(Under) Compliance	-	13,644	15,289	-	480,740	509,673
Allowance Transfers:						
Gavin Reallocation	68,318	58,918	-	1,560	(128,796)	-
P&E Transfers	(2,876)	(1,131)	(4,240)	(136)	8,383	-
Intercompany Puch/(Sales)	106,943	13,287	82,930	33,473	(236,633)	-
Subtotal - Allowance Transfers	172,385	71,074	78,690	34,897	(357,046)	-
Increase/(Decrease) in Allowance Bank	172,385	84,718	93,979	34,897	123,694	509,673
Bank Level - Beginning of Year	116,490	60,473	69,315	24,400	100,984	371,661
Bank Level - End of Year	288,875	145,191	163,294	59,296	224,678	881,334
Financial Statement Effects of Allowance Transfers ($000)						
INCOME STATEMENT:						
Sales for Resale	756	441	558	156	845	2,755
Purchased Power Expense	142	65	60	29	51	346
SO2 Emissions Expense	-	633	2,533	-	4,267	7,434
Net Effect	614	(258)	(2,035)	126	(3,472)	(5,025)
BALANCE SHEET:						
ASSETS:						
Allowance Inventory	13,400	1,048	7,676	4,240	(6,656)	19,707
Accts Receivable - Assoc Co	197	54	441	16	30,277	30,984
Accts Receivable - Other	756	395	450	156	653	2,409
Total Assets	14,352	1,497	8,568	4,411	24,273	53,100
LIABILITIES:						
Accts Payable - Assoc Co	13,738	1,754	10,603	4,285	605	30,984
Other Regulatory Liabilities	-	-	-	-	27,141	27,141
Total Liabilities	13,738	1,754	10,603	4,285	27,745	58,125

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT
MODIFICATION NO. 1
1997 FORECAST

	APCO	CSP	I&M	KYPC	OPCO	SYSTEM
Allowance Transfer Summary (Tons)						
EPA Awarded Allowances	-	88,554	47,489	-	502,821	638,864
Other Allowances - Ormet	-	-	-	-	17,900	17,900
SO2 Emissions	-	(95,600)	(24,700)	-	(350,500)	(470,800)
Over/(Under) Compliance	-	(7,046)	22,789	-	170,221	185,964
Allowance Transfers:						
Gavin Reallocation	50,055	43,866	-	2,133	(96,054)	-
P&E Transfers	(7,318)	(6,084)	(5,033)	(39)	18,474	-
Intercompany Puch/(Sales)	4,619	3,838	22,324	8,977	(39,758)	-
Subtotal - Allowance Transfers	47,356	41,620	17,291	11,071	(117,338)	-
Increase/(Decrease) in Allowance Bank	47,356	34,574	40,080	11,071	52,883	185,964
Bank Level - Beginning of Year	288,875	145,191	163,294	59,296	224,678	881,334
Bank Level - End of Year	336,231	179,765	203,374	70,367	277,562	1,067,298
Financial Statement Effects of Allowance Transfers ($000)						
INCOME STATEMENT:						
Sales for Resale	1,138	655	742	238	1,213	3,985
Purchased Power Expense	152	69	75	32	40	368
SO2 Emissions Expense	-	574	1,831	-	3,510	5,915
Net Effect	985	11	(1,164)	206	(2,337)	(2,298)
BALANCE SHEET:						
ASSETS:						
Allowance Inventory	170	(74)	922	1,252	(3,016)	(746)
Accts Receivable - Assoc Co	477	93	440	5	5,813	6,827
Accts Receivable - Other	1,138	599	675	238	967	3,617
Total Assets	1,785	618	2,037	1,495	3,763	9,698
LIABILITIES:						
Accts Payable - Assoc Co	799	606	3,201	1,289	931	6,827
Other Regulatory Liabilities	-	-	-	-	5,169	5,169
Total Liabilities	799	606	3,201	1,289	6,100	11,996

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT - MODIFICATION No. 1
CALCULATION OF INTERCOMPANY PURCHASES/(SALES)
1996 FORECAST
(TONS)

		APCO	CSP	I&M	KYPC	OPCO	SYSTEM
[A]	Bank Level - Beginning of Year	116,490	60,473	69,315	24,400	100,984	371,661
[B]	Annual Over/(Under) Compliance	-	13,644	15,289	-	480,740	509,673
[C]	Gavin Reallocation	68,318	58,918	-	1,560	(128,796)	-
[D]	P&E Transfers	(2,876)	(1,131)	(4,240)	(136)	8,383	-
[E] = [A]+[B]+[C]+[D]	Subtotal	181,932	131,904	80,364	25,824	461,311	881,334
[F]	December 1996 MLR	0.32777	0.16474	0.18528	0.06728	0.25493	1.00000
[G] = [F] * 881,334	MLR-Share of System Allowance Bank	288,875	145,191	163,294	59,296	224,678	881,334
[H] = [G] - [E]	Purchases/(Sales) Required to Achieve MLR-Share of System Allowance Bank	106,943	13,287	82,930	33,473	(236,633)	-

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT - MODIFICATION No. 1
CALCULATION OF INTERCOMPANY PURCHASES/(SALES)
1997 FORECAST
(TONS)

		APCO	CSP	I&M	KYPC	OPCO	SYSTEM
[A]	Bank Level - Beginning of Year	288,875	145,191	163,294	59,298	224,678	881,334
[B]	Annual Over/(Under) Compliance	-	(7,046)	22,789	-	170,221	185,964
[C]	Gavin Reallocation	50,055	43,866	-	2,133	(96,054)	-
[D]	P&E Transfers	(7,318)	(6,084)	(5,033)	(39)	18,474	-
[E] = [A]+[B]+[C]+[D]	Subtotal	331,612	175,927	181,050	61,390	317,319	1,067,298
[F]	December 1997 MLR	0.31503	0.16843	0.19055	0.06593	0.26006	1.00000
[G] = [F] * 1,067,298	MLR-Share of System Allowance Bank	336,231	179,765	203,374	70,367	277,562	1,067,298
[H] = [G] - [E]	Purchases/(Sales) Required to Achieve MLR-Share of System Allowance Bank	4,619	3,838	22,324	8,977	(39,758)	-

APPENDIX B

PROCEEDS/COSTS ASSOCIATED WITH THIRD PARTY SALES/PURCHASES, PREVIOUSLY DEFERRED

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT
MODIFICATION No. 1
($000)

Member's Share of Proceeds/(Costs) Associated with Third Party Allowance Transactions

	APCO	CSP	I&M	KYPC	OPCO	SYSTEM
Proceeds from EPA Auctions	819	574	560	151	3,383	5,487
Proceeds from Other Allowance Sales	11,788	5,421	5,949	2,240	9,305	34,703
Cost of Purchased Allowances	(503)	(231)	(254)	(96)	(397)	(1,480)
Total	12,104	5,763	6,256	2,296	12,291	38,710

AEP System
Allowance Purchases/Sales
Deferred Pending Final Agreement
($000)

	APCO	CSP	I&M	KYPC	OPCO	SYSTEM
EPA Auction Proceeds						
1993 Auction Proceeds	212	162	158	39	1,002	1,573
1994 Auction Proceeds	291	198	193	54	1,142	1,878
1995 Auction Proceeds	250	168	164	46	964	1,592
Subtotal	753	528	515	139	3,108	5,043
Plus Accrued Carrying Charge through May 1996	66	46	45	12	275	444
Total Credit to be Retained by each Member	819	574	560	151	3,383	5,487
Allowance Sales						
1994 Sale of Allowances						31,619
Plus Accrued Carrying Charge through May 1996						3,084
Total						34,703
March 1994 MLR	0.33968	0.15620	0.17144	0.06456	0.26812	1.00000
Member's Share of Net Proceeds	11,788	5,421	5,949	2,240	9,305	34,703
Allowance Purchases						
1994 EPA Auction Purchase of 8,788 allowances						(1,287)
Plus Accrued Carrying Charge through May 1996						(193)
Total Cost						(1,480)
March 1994 MLR	0.33968	0.15620	0.17144	0.06456	0.26812	1.00000
Member's Share of Purhcase Price	(503)	(231)	(254)	(96)	(397)	(1,480)

APPENDIX C

COMPARISON OF REVENUE REQUIREMENTS

BASE CASE (IAA) vs MLR CASE (MODIFICATION No. 1 to the IAA)

AEP System
Comparison of Revenue Requiments
Base Case vs MLR Case
($ Millions)

	APCO	CSP	I&M	KYPC	OPCO	TOTAL
5 Year Average						
Base Case	1,551	1,053	1,131	292	1,594	5,621
MLR Case	1,551	1,051	1,135	292	1,585	5,614
Change	-	(2)	4	-	(9)	(7)
10 Year Average						
Base Case	1,743	1,191	1,253	342	1,748	6,277
MLR Case	1,740	1,188	1,253	340	1,753	6,274
Change	(3)	(3)	-	(2)	5	(3)
20 Year NPV @10.14%						
Base Case	16,647	11,579	11,539	3,298	15,916	58,979
MLR Case	16,638	11,574	11,536	3,298	15,932	58,978
Change	(9)	(5)	(3)	-	16	(1)

Note:

Forecast data based on AEP System Acid Rain Compliance Plan, filed before the P.U.C.O. on October 14, 1994.

REVENUE REQUIREMENTS

BASE CASE

APCO
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

		Effect of Interim Allowance Agreement				Total
	Base Level	Internal Sales	External Sales	Consumed Allowances	Subtotal	Revenue Requirement
1995	1,439	0.0	0.0	0.0	0.0	1,439
1996	1,484	0.0	0.0	0.0	0.0	1,484
1997	1,551	0.0	0.0	0.0	0.0	1,551
1998	1,611	0.0	0.0	0.0	0.0	1,611
1999	1,669	0.0	0.0	0.0	0.0	1,669
2000	1,772	0.0	0.0	1.6	1.6	1,774
2001	1,855	0.0	0.0	1.1	1.1	1,856
2002	1,930	0.0	0.0	0.7	0.7	1,931
2003	2,017	0.0	0.0	0.4	0.4	2,017
2004	2,098	0.0	0.0	0.3	0.3	2,098
2005	2,201	0.0	0.0	0.2	0.2	2,201
2006	2,337	0.0	0.0	0.1	0.1	2,337
2007	2,464	0.0	0.0	0.1	0.1	2,4
2008	2,555	0.0	0.0	0.0	0.0	2,55
2009	2,761	0.0	0.0	0.0	0.0	2,761
2010	2,929	0.0	0.0	23.3	23.3	2,952
2011	3,087	0.0	0.0	17.1	17.1	3,104
2012	3,246	0.0	0.0	12.1	12.1	3,258
2013	3,339	0.0	0.0	13.2	13.2	3,352
2014	3,545	0.0	0.0	4.6	4.6	3,550

5-yr Average	1,551	0.0	0.0	0.0	0.0	1,551
10-yr Average	1,743	0.0	0.0	0.4	0.4	1,743
NPV @ 10.14%	16,632	0.0	0.0	15.4	15.4	16,647

CSP
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	976	0.0	0.0	0.1	0.1	976
1996	1,009	0.0	0.0	0.2	0.2	1,009
1997	1,051	0.0	0.0	0.1	0.1	1,051
1998	1,094	0.0	0.0	0.1	0.1	1,094
1999	1,133	0.0	0.0	0.1	0.1	1,133
2000	1,214	0.0	0.0	0.1	0.1	1,214
2001	1,269	0.0	0.0	0.1	0.1	1,269
2002	1,326	0.0	0.0	0.1	0.1	1,326
2003	1,388	0.0	0.0	0.1	0.1	1,388
2004	1,451	0.0	0.0	0.0	0.0	1,451
2005	1,536	0.0	0.0	0.0	0.0	1,536
2006	1,632	0.0	0.0	0.0	0.0	1,632
2007	1,736	0.0	0.0	0.0	0.0	1,736
2008	1,810	(4.1)	0.0	0.0	(4.1)	1,806
2009	1,999	0.0	0.0	0.0	0.0	1,999
2010	2,177	0.0	0.0	7.5	7.5	2,185
2011	2,269	0.0	0.0	13.5	13.5	2,283
2012	2,378	0.0	0.0	12.7	12.7	2,391
2013	2,447	0.0	0.0	13.6	13.6	2,461
2014	2,495	0.0	0.0	15.6	15.6	2,511

5-yr Average	1,053	0.0	0.0	0.1	0.1	1,053
10-yr Average	1,191	0.0	0.0	0.1	0.1	1,191
NPV @ 10.14%	11,568	(1.1)	0.0	11.5	10.5	11,579

I&M
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	1,050	0.0	0.0	0.7	0.7	1,051
1996	1,091	0.0	0.0	1.7	1.7	1,093
1997	1,156	0.0	0.0	0.8	0.8	1,157
1998	1,158	0.0	0.0	0.3	0.3	1,158
1999	1,195	0.0	0.0	0.1	0.1	1,195
2000	1,267	0.0	0.0	0.0	0.0	1,267
2001	1,312	0.0	0.0	0.0	0.0	1,312
2002	1,368	0.0	0.0	0.0	0.0	1,368
2003	1,431	0.0	0.0	0.0	0.0	1,431
2004	1,497	0.0	0.0	0.0	0.0	1,497
2005	1,518	0.0	0.0	0.0	0.0	1,518
2006	1,594	0.0	0.0	0.0	0.0	1,594
2007	1,672	0.0	0.0	0.0	0.0	1,[illegible]
2008	1,727	(6.1)	0.0	0.0	(6.1)	1,721
2009	1,781	0.0	0.0	0.0	0.0	1,781
2010	1,806	0.0	0.0	0.4	0.4	1,806
2011	1,860	0.0	0.0	3.4	3.4	1,863
2012	1,972	0.0	0.0	3.4	3.4	1,975
2013	2,066	0.0	0.0	3.5	3.5	2,070
2014	2,256	0.0	0.0	0.6	0.6	2,257

5-yr Average	1,130	0.0	0.0	0.7	0.7	1,131
10-yr Average	1,253	0.0	0.0	0.4	0.4	1,253
NPV @ 10.14%	11,536	(1.6)	0.0	4.9	3.3	11,539

KYPC
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	264	0.0	0.0	0.0	0.0	264
1996	279	0.0	0.0	0.0	0.0	279
1997	293	0.0	0.0	0.0	0.0	293
1998	304	0.0	0.0	0.0	0.0	304
1999	318	0.0	0.0	0.0	0.0	318
2000	349	0.0	0.0	11.6	11.6	361
2001	365	0.0	0.0	10.9	10.9	376
2002	382	0.0	0.0	9.6	9.6	392
2003	401	0.0	0.0	9.1	9.1	410
2004	417	0.0	0.0	8.4	8.4	425
2005	453	0.0	0.0	7.2	7.2	460
2006	472	0.0	0.0	6.3	6.3	478
2007	495	0.0	0.0	6.1	6.1	501
2008	511	0.0	0.0	12.6	12.6	524
2009	538	0.0	0.0	24.1	24.1	562
2010	563	0.0	0.0	18.9	18.9	582
2011	604	0.0	0.0	23.6	23.6	628
2012	648	0.0	0.0	24.8	24.8	673
2013	668	0.0	0.0	27.5	27.5	696
2014	689	0.0	0.0	31.1	31.1	720

5-yr Average	292	0.0	0.0	0.0	0.0	292
10-yr Average	337	0.0	0.0	5.0	5.0	342
NPV @ 10.14%	3,238	0.0	0.0	60.5	60.5	3,298

OPCO
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	1,518	(21.2)	0.0	0.0	(21.2)	1,497
1996	1,566	(20.1)	0.0	0.0	(20.1)	1,546
1997	1,599	0.0	0.0	0.1	0.1	1,599
1998	1,647	0.0	0.0	0.1	0.1	1,647
1999	1,683	0.0	0.0	0.1	0.1	1,683
2000	1,803	0.0	(135.9)	0.1	(135.8)	1,667
2001	1,867	0.0	0.0	1.0	1.0	1,868
2002	1,905	0.0	0.0	12.1	12.1	1,917
2003	1,978	0.0	0.0	13.8	13.8	1,992
2004	2,048	0.0	0.0	17.9	17.9	2,066
2005	2,093	0.0	0.0	5.1	5.1	2,098
2006	2,179	0.0	0.0	0.9	0.9	2,180
2007	2,261	0.0	0.0	0.2	0.2	2,[illegible]
2008	2,310	(1.5)	0.0	0.0	(1.5)	2,3[illegible]
2009	2,427	(36.9)	0.0	0.0	(36.9)	2,390
2010	2,407	(41.1)	0.0	0.1	(41.0)	2,366
2011	2,603	(57.7)	(2.8)	0.0	(60.5)	2,543
2012	2,743	(51.9)	(22.3)	0.0	(74.2)	2,669
2013	2,791	(58.0)	(22.4)	0.1	(80.3)	2,711
2014	3,030	(44.1)	(44.0)	0.1	(88.0)	2,942

5-yr Average	1,603	(8.3)	0.0	0.1	(8.2)	1,594
10-yr Average	1,761	(4.1)	(13.6)	4.5	(13.2)	1,748
NPV @ 10.14%	16,075	(89.6)	(90.5)	21.1	(159.0)	15,916

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT - Base Case w/ Allowance Sales
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	5,247	(21.2)	0.0	0.8	(20.4)	5,227
1996	5,429	(20.1)	0.0	1.9	(18.2)	5,411
1997	5,650	0.0	0.0	1.0	1.0	5,651
1998	5,814	0.0	0.0	0.5	0.5	5,815
1999	5,998	0.0	0.0	0.3	0.3	5,998
2000	6,405	0.0	(135.9)	13.4	(122.5)	6,283
2001	6,668	0.0	0.0	13.1	13.1	6,681
2002	6,911	0.0	0.0	22.5	22.5	6,934
2003	7,215	0.0	0.0	23.4	23.4	7,238
2004	7,511	0.0	0.0	26.6	26.6	7,538
2005	7,801	0.0	0.0	12.5	12.5	7,814
2006	8,214	0.0	0.0	7.3	7.3	8,221
2007	8,628	0.0	0.0	6.4	6.4	8,634
2008	8,913	(11.7)	0.0	12.6	0.9	8,914
2009	9,506	(36.9)	0.0	24.1	(12.8)	9,493
2010	9,882	(41.1)	0.0	50.2	9.1	9,891
2011	10,423	(57.7)	(2.8)	57.6	(2.9)	10,420
2012	10,987	(51.9)	(22.3)	53.0	(21.2)	10,966
2013	11,311	(58.0)	(22.4)	57.9	(22.5)	11,289
2014	12,015	(44.1)	(44.0)	52.0	(36.1)	11,979

5-yr Average	5,628	(8.3)	0.0	0.9	(7.4)	5,620
10-yr Average	6,285	(4.1)	(13.6)	10.4	(7.4)	6,277
NPV @ 10.14%	59,048	(92.2)	(90.5)	113.4	(69.4)	58,979

REVENUE REQUIREMENTS

MLR CASE

APCO
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	1,439	0.0	0.0	0.0	0.0	1,439
1996	1,484	0.0	0.0	0.0	0.0	1,484
1997	1,551	0.0	0.0	0.0	0.0	1,551
1998	1,611	0.0	0.0	0.0	0.0	1,611
1999	1,669	0.0	0.0	0.0	0.0	1,669
2000	1,772	(6.4)	(31.0)	11.6	(25.8)	1,746
2001	1,855	(6.8)	0.0	8.6	1.8	1,857
2002	1,930	(4.9)	0.0	5.6	0.7	1,931
2003	2,017	(4.9)	0.0	3.6	(1.3)	2,016
2004	2,098	(6.0)	0.0	2.2	(3.8)	2,094
2005	2,201	(2.6)	0.0	1.2	(1.4)	2,200
2006	2,337	0.0	0.0	0.6	0.6	2,338
2007	2,464	0.0	0.0	1.5	1.5	2,466
2008	2,555	0.0	0.0	9.0	9.0	2,564
2009	2,761	0.0	0.0	22.9	22.9	2,784
2010	2,929	0.0	0.0	23.9	23.9	2,953
2011	3,087	0.0	(0.8)	17.9	17.1	3,104
2012	3,246	0.0	(6.0)	16.4	10.4	3,256
2013	3,339	0.0	(5.9)	18.4	12.5	3,352
2014	3,545	0.0	(11.9)	18.7	6.8	3,552

5-yr Average	1,551	0.0	0.0	0.0	0.0	1,551
10-yr Average	1,743	(2.9)	(3.1)	3.2	(2.8)	1,740
NPV @ 10.14%	16,632	(14.5)	(21.2)	41.6	5.8	16,638

CSP
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	976	(3.5)	0.0	0.0	(3.5)	973
1996	1,009	0.0	0.0	0.1	0.1	1,009
1997	1,051	(1.5)	0.0	0.1	(1.4)	1,050
1998	1,094	(1.7)	0.0	0.1	(1.6)	1,092
1999	1,133	(1.1)	0.0	0.0	(1.1)	1,132
2000	1,214	(2.1)	(23.3)	0.0	(25.4)	1,189
2001	1,269	(0.4)	0.0	0.0	(0.4)	1,269
2002	1,326	0.0	0.0	1.3	1.3	1,327
2003	1,388	0.0	0.0	2.3	2.3	1,390
2004	1,451	0.0	0.0	3.1	3.1	1,454
2005	1,536	0.0	0.0	3.7	3.7	1,540
2006	1,632	0.0	0.0	4.8	4.8	1,637
2007	1,736	0.0	0.0	6.6	6.6	1,743
2008	1,810	0.0	0.0	9.5	9.5	1,820
2009	1,999	0.0	0.0	14.7	14.7	2,014
2010	2,177	0.0	0.0	15.5	15.5	2,193
2011	2,269	0.0	(0.4)	15.0	14.6	2,284
2012	2,378	0.0	(2.9)	15.0	12.1	2,390
2013	2,447	0.0	(2.9)	16.2	13.3	2,460
2014	2,495	0.0	(5.2)	22.9	17.7	2,513

5-yr Average	1,053	(1.6)	0.0	0.1	(1.5)	1,051
10-yr Average	1,191	(1.0)	(2.3)	0.7	(2.7)	1,188
NPV @ 10.14%	11,568	(7.5)	(14.9)	28.3	5.9	11,574

I&M
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	1,050	0.0	0.0	3.4	3.4	1,053
1996	1,091	0.0	0.0	4.0	4.0	1,095
1997	1,156	0.0	0.0	4.8	4.8	1,161
1998	1,158	0.0	0.0	5.1	5.1	1,163
1999	1,195	0.0	0.0	5.4	5.4	1,200
2000	1,267	(3.9)	(17.5)	6.4	(15.0)	1,252
2001	1,312	(4.4)	0.0	4.7	0.3	1,312
2002	1,368	(3.8)	0.0	3.2	(0.6)	1,367
2003	1,431	(4.7)	0.0	2.2	(2.5)	1,429
2004	1,497	(6.2)	0.0	1.4	(4.8)	1,492
2005	1,518	(6.0)	0.0	0.8	(5.2)	1,513
2006	1,594	(7.6)	0.0	0.4	(7.2)	1,587
2007	1,672	(9.1)	0.0	0.2	(8.9)	1,663
2008	1,727	(9.1)	0.0	3.3	(5.8)	1,721
2009	1,781	(4.1)	0.0	4.6	0.5	1,782
2010	1,806	(1.0)	0.0	5.8	4.8	1,811
2011	1,860	0.0	(0.5)	4.3	3.8	1,864
2012	1,972	0.0	(3.8)	6.3	2.5	1,975
2013	2,066	0.0	(3.7)	7.1	3.4	2,069
2014	2,256	0.0	(7.3)	8.6	1.3	2,257

5-yr Average	1,130	0.0	0.0	4.5	4.5	1,135
10-yr Average	1,253	(2.3)	(1.8)	4.1	0.0	1,253
NPV @ 10.14%	11,536	(21.1)	(12.2)	33.6	0.3	11,536

KYPC
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

		Effect of Interim Allowance Agreement				
	Base Level	Internal Sales	External Sales	Consumed Allowances	Subtotal	Total Revenue Requirement
1995	264	0.0	0.0	0.0	0.0	264
1996	279	0.0	0.0	0.0	0.0	279
1997	293	0.0	0.0	0.0	0.0	293
1998	304	0.0	0.0	0.0	0.0	304
1999	318	0.0	0.0	0.0	0.0	318
2000	349	0.0	(4.8)	9.6	4.8	354
2001	365	0.0	0.0	7.6	7.6	373
2002	382	0.0	0.0	6.2	6.2	388
2003	401	0.0	0.0	6.4	6.4	407
2004	417	0.0	0.0	7.2	7.2	424
2005	453	0.0	0.0	10.4	10.4	463
2006	472	0.0	0.0	13.6	13.6	486
2007	495	0.0	0.0	15.7	15.7	511
2008	511	0.0	0.0	18.4	18.4	529
2009	538	0.0	0.0	21.3	21.3	559
2010	563	0.0	0.0	23.6	23.6	587
2011	604	0.0	(0.1)	24.3	24.2	628
2012	648	0.0	(0.7)	25.4	24.7	673
2013	668	0.0	(0.6)	28.1	27.5	696
2014	689	0.0	(1.0)	32.5	31.5	721

5-yr Average	292	0.0	0.0	0.0	0.0	292
10-yr Average	337	0.0	(0.5)	3.7	3.2	340
NPV @ 10.14%	3,238	0.0	(3.1)	63.0	60.0	3,298

OPCO
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

	Base Level	Effect of Interim Allowance Agreement				Total Revenue Requirement
		Internal Sales	External Sales	Consumed Allowances	Subtotal	
1995	1,518	(17.0)	0.0	0.0	(17.0)	1,501
1996	1,566	(29.5)	0.0	0.0	(29.5)	1,537
1997	1,599	(13.7)	0.0	0.2	(13.5)	1,586
1998	1,647	(13.2)	0.0	0.2	(13.0)	1,634
1999	1,683	(16.3)	0.0	0.3	(16.0)	1,667
2000	1,803	0.0	(33.3)	8.1	(25.2)	1,778
2001	1,867	0.0	0.0	11.2	11.2	1,878
2002	1,905	0.0	0.0	8.4	8.4	1,913
2003	1,978	0.0	0.0	6.1	6.1	1,984
2004	2,048	0.0	0.0	5.5	5.5	2,054
2005	2,093	(5.7)	0.0	2.4	(3.3)	2,090
2006	2,179	(10.0)	0.0	1.4	(8.6)	2,170
2007	2,261	(13.4)	0.0	1.2	(12.2)	2,249
2008	2,310	(13.5)	0.0	8.2	(5.3)	2,305
2009	2,427	(38.8)	0.0	5.7	(33.1)	2,394
2010	2,407	(43.4)	0.0	4.9	(38.5)	2,369
2011	2,603	(59.3)	(0.8)	0.4	(59.7)	2,543
2012	2,743	(66.1)	(5.6)	0.0	(71.7)	2,671
2013	2,791	(73.8)	(5.6)	0.2	(79.2)	2,712
2014	3,030	(77.8)	(11.0)	0.1	(88.7)	2,941

5-yr Average	1,603	(17.9)	0.0	0.1	(17.8)	1,585
10-yr Average	1,761	(9.0)	(3.3)	4.0	(8.3)	1,753
NPV @ 10.14%	16,075	(146.0)	(22.3)	25.5	(142.8)	15,932

AEP SYSTEM
INTERIM ALLOWANCE AGREEMENT - MLR CASE
REVENUE REQUIREMENTS
($ MILLIONS)

		Effect of Interim Allowance Agreement				Total
	Base Level	Internal Sales	External Sales	Consumed Allowances	Subtotal	Revenue Requirement
1995	5,247	(20.5)	0.0	3.4	(17.1)	5,230
1996	5,429	(29.5)	0.0	4.1	(25.4)	5,404
1997	5,650	(15.2)	0.0	5.1	(10.1)	5,640
1998	5,814	(14.9)	0.0	5.4	(9.5)	5,805
1999	5,998	(17.4)	0.0	5.7	(11.7)	5,986
2000	6,405	(12.4)	(109.9)	35.7	(86.6)	6,318
2001	6,668	(11.6)	0.0	32.1	20.5	6,689
2002	6,911	(8.7)	0.0	24.7	16.0	6,927
2003	7,215	(9.6)	0.0	20.6	11.0	7,226
2004	7,511	(12.2)	0.0	19.4	7.2	7,518
2005	7,801	(14.3)	0.0	18.5	4.2	7,805
2006	8,214	(17.6)	0.0	20.8	3.2	8,217
2007	8,628	(22.5)	0.0	25.2	2.7	8,631
2008	8,913	(22.6)	0.0	48.4	25.8	8,939
2009	9,506	(42.9)	0.0	69.2	26.3	9,532
2010	9,882	(44.4)	0.0	73.7	29.3	9,911
2011	10,423	(59.3)	(2.6)	61.9	0.0	10,423
2012	10,987	(66.1)	(19.0)	63.1	(22.0)	10,965
2013	11,311	(73.8)	(18.7)	70.0	(22.5)	11,289
2014	12,015	(77.8)	(36.4)	82.8	(31.4)	11,984

5-yr Average	5,628	(19.5)	0.0	4.7	(14.8)	5,613
10-yr Average	6,285	(15.2)	(11.0)	15.6	(10.6)	6,274
NPV @ 10.14%	59,048	(189.1)	(73.7)	192.1	(70.7)	58,977

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation : Docket No. ER96-______-000

NOTICE OF FILING

(date)

Take notice that on (date), American Electric Power Service Corporation, on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company, (the AEP Companies) tendered for filing an amendment to the AEP System Interim Allowance Agreement. The purpose of the amendment to the Agreement is to establish the allocation of costs and revenues related to the sale or purchase of allowances to or from non-affiliated companies.

The AEP Companies request an effective date of September 1, 1996, but the Amendment relates back to the effective date of the Agreement.

Copies have been served upon the state regulatory commissions in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, 1A, Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 384.211 and 18 CFR 385.214). All such motions or protests should be filed on or before __________________. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestant parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell, Secretary

Kentucky Power Company

REQUEST

Refer to page 3, paragraph 6, of the Application. It states, "[i]t is unknown at this time whether the AEP Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers, or if each company will operate independently."

a. Explain when a decision concerning the future of the AEP Pool Agreement is expected.

b. Describe any potential financial impact the termination of the AEP Pool Agreement will have on Kentucky Power's ratepayers.

RESPONSE

a. The decision to terminate the existing AEP Interconnection Agreement was made in December 2010 per the notices provided in the Company's response to Staff 1-1. A replacement agreement is currently under evaluation and the Company anticipates that a filing will be made at FERC by the end of the first quarter of 2012.

b. The estimated impacts of a new agreement are currently under development as part of the evaluation referenced in the Company's response to 2a. above.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 4 and 5, paragraph 9, of the Application, which discusses the Consent Decree in United States v. American Electric Power Service Corp., Civil Action C2-99-1250 ("Consent Decree") entered by the United States District Court for the Southern District of New York. Provide the following:

a. Provide the date on which the civil action was filed;

b. Provide a copy of the Consent Decree;

c. If not specifically identified in the Consent Decree, provide a list of the AEP generating facilities which were subject to the Consent Decree; and

d. If any AEP generating facilities are subject to the Consent Decree but were not the subject of the civil action, explain why those facilities are subject to the Consent Decree.

RESPONSE

a. The initial civil action was filed on November 3, 1999 by the U.S. Department of Justice on behalf of the U.S. EPA.

b. Please refer to Attachment 1 to this response for a copy of the NSR Consent Decree and Attachment 2 to this response for the 2010 modification to the NSR Consent Decree.

c. The list of AEP generating facilities which are subject to the Consent Decree are specifically identified in the Consent Decree.

d. During the eight years that AEP's NSR enforcement action was pending, EPA and various states and nongovernmental organizations had filed numerous additional actions against coal-fired utility generating units. Because generating resources in the AEP Eastern System were planned and operated pursuant to the AEP Interconnection Agreement, and only a few units in the AEP Eastern System were not included in the then-pending complaints, AEP investigated whether a consent decree that covered all of the units in the AEP Eastern System could be negotiated that would protect all units from further litigation for both past maintenance activities and for actions that would be taken to continue to maintain and operate the units in compliance with increasingly stringent environmental requirements. The Consent Decree ultimately executed by the AEP operating companies includes all units operated by AEP in the AEP Eastern System, and is based on a flexible system cap for SO2 and NOx emissions that declines over an extended period, but imposes no unit-specific emission limits on any individual unit, except for PM emission rates on three specific units that were the subject of PM-related allegations in the EPA's amended complaint. The Consent Decree therefore provided significant benefits to the additional units while at the same time providing certainty regarding the compliance plans that had already been developed to assure future compliance with the Clean Air Interstate Rule and the Clean Air Mercury Rule. Although both of these rules were later reversed on appeal, the compliance plans developed for them are equally effective for the replacement Cross-State Air Pollution Rule and the Utility MACT rule.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 7, paragraph 15, of the Application. It states, "Kentucky Power currently anticipates retiring Big Sandy Unit 1 by January 1, 2015, and will make all requisite filings related to this retirement by separate application." Explain Kentucky Power's reasons for retiring Big Sandy Unit No. 1 by January 1, 2015.

RESPONSE

Big Sandy Unit 1 will be retired when the new EPA MATS rule (previously called Utility MACT or HAPS) goes into effect, which at the time of the CPCN filing, was thought to be 1/1/2015. Given the final EPA MATS rule that was released in December of 2011, the effective date may be on or about March 2015 (three years after the rule is published in the CFR).

The MATS rule requires units to meet very stringent limits on particulate matter, mercury, and acid aerosol emissions on a pound per million btu basis. KPCo believes that BS1 would need significant investment in environmental retrofits to meet these MATS limits. The overall scope and cost of the BS1 environmental retrofit was deemed uneconomic due to the high cost and small capacity of the unit.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 7, lines 7-8, of the Direct Testimony of John M. McManus ("McManus Testimony").

a. Provide the annual NOX, and SO_2 allowance caps for Kentucky as established by the Cross-State Air Pollution Rule ("CSAPR").

b. Provide the ozone season NO_X, allowance cap for Kentucky.

c. For 2010, provide the tons of NO_X, and SO_2 emitted by Big Sandy Units 1 and 2.

RESPONSE

a. Please see KPSC 1-5a Attachment 1 for the annual NOx and SO_2 emission allowance budgets, variability limits, and state assurance levels for the Commonwealth of Kentucky, per CSAPR as finalized by the EPA on July 6, 2011. The assurance provision allowance is the method to account for operational demand and variability under CSAPR.

b. Please see KPSC 1-5b Attachment 1 for the seasonal NOx emission allowance budgets, variability limits, and state assurance levels for the Commonwealth of Kentucky, per CSAPR as finalized by the EPA on July 6, 2011. The assurance provision allowance is the method to account for operational demand and variability under CSAPR.

c. The tons of NOx and SO_2 emitted by Big Sandy Units 1 and 2 during 2010 are:

Annual NOx (2010)	
Unit 1 -	890.4 tons
Unit 2 -	3765.2 tons

Annual SO2 (2010)	
Unit 1 -	5,643.3 tons
Unit 2 -	37,280.8 tons

Seasonal NOx (2010)	
Unit 1 -	460.1 tons
Unit 2 -	1763.4 tons

WITNESS: John M McManus

KPSC Case No. 2001-00401
Commission Staff's First Set of Data Requests
Order Dated January 13, 2012
Item No. 5a
1 of 1

State Budgets, Variability Limits, and Assurance Levels for
NOx Emissions (Thousand Tons)

State	Budget		Variability Limit		State Assurance Level	
	2012	2014	2012	2014	2012	2014
Kentucky	85.086	77.238	15.315	13.903	100.401	91.141

State Budgets, Variability Limits, and Assurance Levels for
SO_2 Emissions (Thousand Tons)

State	SO_2 Group *	Budget		Variability Limit		State Assurance Level	
		2012	2014	2012	2014	2012	2014
Kentucky	1	232.662	106.284	41.879	19.131	274.541	125.415

* The final CSAPR divides the states required to reduce SO2 into two groups. Both groups must reduce their SO2 emissions beginning in 2012. Group 1 states must make significant additional reductions in SO2 emissions by 2014 in order to eliminate their significant contribution to air quality problems in downwind areas.

State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_X Emissions (Thousand Tons)

State	Budget		Variability Limit		State Assurance Level	
	2012	2014	2012	2014	2012	2014
Kentucky	36.167	32.674	7.595	6.862	43.762	39.536

Kentucky Power Company

REQUEST

Refer to the McManus testimony at page 7, lines 10 and 11.

a. Explain whether Kentucky exceeds its annual allocation of NO_X, and SO_2 allowances by 18 percent.

b. During 2010, did Big Sandy Unit 1or 2 exceed the CSAPR annual allowance caps by 18 percent? If so, by how much did they exceed the CSAPR caps?

RESPONSE

a. The Commonwealth of Kentucky does not exceed its annual budgets of NOx and SO2 allowances for 2012 by 18 percent, based on 2010 data. However, based on this data the Commonwealth exceeds its annual budgets for 2012 by a margin [less than 18%]. For 2014, Kentucky exceeds its annual SO_2 budget plus the 18% by 146,094 tons; the annual NOx budget plus 18% by 684 tons; and the seasonal NOx budget plus 18% by 475 tons.

<u>2010 Actual Kentucky Annual Emissions (tons) for the Acid Rain Program:</u>
Annual SO_2 = 271,509.2
Annual NOx = 91,824.3
Seasonal NOx = 39,030.2

b.
Using 2010 emissions data, Big Sandy Units 1 and 2 would exceed the annual SO_2 budgeted allowances for 2012 by:
Unit 1 - 66.0%
Unit 2 - 212.6%

Using 2010 emissions data, Big Sandy Units 1 and 2 would exceed the annual SO_2 budgeted allowances for 2014 by:
Unit 1 - 286.0%
Unit 2 - 626.6%

Using 2010 emissions data, Big Sandy Units 1 and 2 would not exceed the Annual NOx budgeted allowance for 2012. During 2010, Big Sandy Unit 1 would not exceed the annual NOx budgeted allowance for 2014.

Using 2010 emissions data, Big Sandy Unit 2 would exceed the Annual NOx budgeted allowance for 2014 by:
Unit 2 - 0.3%

Using 2010 emissions data, Big Sandy Unit 2 would exceed the Seasonal NOx budgeted allowance for 2012 and 2014 by:

Unit 2 2012 - 3.4%
Unit 2 2014 - 16.7%

Using 2010 emissions data, Big Sandy Unit 1 would not exceed the Seasonal NOx budgeted allowance for 2012 and 2014.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 12 of the McManus Testimony, lines 14-20. It states, "(i)n addition, as supported by Company witness Weaver, the extraordinary brief compliance window will require KPCo to operate Big Sandy Unit 2 in an uncontrolled fashion, but under a potentially constrained dispatch. This is due to the fact that the timeframe to permit and install an FGD system is beyond the proposed compliance window as discussed by Company witness Walton. In essence, the timing contained in the rule already puts us behind schedule."

a. Explain how the compliance timeline contained in CSAPR already puts Kentucky Power behind schedule.

b. Explain when Kentucky Power first became aware that installation of a wet or dry Flue Gas Desulfurization system ("FGD" or "scrubber") on Unit 2 would be required on the unit in order to comply with the Environmental Protection Agency ("EPA") requirements.

RESPONSE

a. The final CSAPR issued in July, 2011, established SO_2 allowance budgets for Kentucky and for Big Sandy Plant at levels well below historical emissions, effective in 2012. The rule also set even more stringent budgets in 2014. Installation of FGD technology on Big Sandy Unit 2 with other measures would enable the plant to comply with CSAPR, but it is not possible to have the technology installed and operational in this time frame. Thus, the rule "already puts us behind schedule."

b. Kentucky Power first became aware that installation of a wet or dry Flue Gas Desulfurization system ("FGD" or "scrubber") on Unit 2 could be required with the proposal of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) in December, 2003. CAIR established more stringent SO_2 requirements, which an FGD system could help achieve, and CAMR established a mercury requirement that the FGD, in combination with the existing selective catalytic reduction system (SCR), could help achieve.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 14 of the McManus Testimony, lines 12-17. It states, "the Consent Decree requires installation of a FGD system on Unit 2 by the end of 2015. This aligns with the compliance schedule for the MACT ["Maximum Achievable Control Technology"] rule assuming an additional year for a major retrofit. While the CSAPR program will result in having to reduce SO_2 emissions from the unit prior to that time, it can be achieved with curtailment of operation and supplementing the allowance allocation with allowances from other sources."

a. Explain what is meant by curtailment of operation, including but not limited to the number of hours per year of operation and the percentage of available generation.

b. Explain further supplementing the allowance allocation with allowances from other sources including the source of allowances, the number of allowances, and the associated costs of those allowances.

RESPONSE

a. Curtailment of operation means operating the Big Sandy units at lower capacity factors than historically in order to reduce emissions. Under the CSAPR rule, Big Sandy Unit 2 is issued SO_2 allowances that are significantly below the Unit's historic annual SO_2 emissions. Evaluation of the past three years of annual SO_2 emissions for Big Sandy Unit 2 indicates that the CSAPR allocation is less than 1/3 of the Unit's average annual SO_2 emissions. It is not possible at this time to determine what the hours of operation would be.

b. CSAPR allows facilities to purchase additional allowances from the market to meet their compliance obligation. Due to the stringency of the total allowance allocations provided to sources under CSAPR as well as the current stay of the rule, it is uncertain at this time how many allowances will be available on the market as well as the allowance price structure. Please refer to the Company's response to Staff 1-93 for the Company's estimated forecast on the number of allowances and the associated costs of those allowances. "Sources" in the market include any entity that owns CSAPR allowances, and are typically utility companies who are allocated allowances from USEPA.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 17 of the McManus Testimony, lines 10-1 2, which indicates that it is estimated that the "issuance of the modified air permit" will take up to 18 months from the time the application is submitted.

a. What is the basis for the 18-month estimate?

b. Discuss the impact on construction and compliance if the issuance of the modified air permit takes longer than 18 months.

RESPONSE

a. The basis for the "up to 18-month" estimate is prior experience in obtaining permits for the installation of major pollution control systems. However, the Company will work with the Kentucky Division of Air Quality to expedite the permitting process.

b. Project construction cannot commence until approval of the air permit is received from the Kentucky Division for Air Quality. The DFGD project schedule, Exhibit RLW-1, provided in the direct testimony of Company witness Walton depicts an in-service date based on a 12-month approval for the air permit. Delays past the 12 month approval period could impact the project month-for-month. Potential impacts include commercial adjustments to negotiated contracts with labor contractors and equipment vendors. In addition, the inability to meet compliance dates with environmental regulations and the Consent Decree may occur.

In the event there is a delay in the approval of the air permit past the planned 12 months, the Company would need to look at the potential for, and costs of, construction acceleration and determine the cost/benefit to reach a decision.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 24 of the McManus Testimony, lines 2-4. It states, "the 2007 NSR ["New Source Review"] Consent Decree requires the Company to move quickly on the retrofit of equipment for Big Sandy Unit 2 in order to ensure that it remains a source of reliable, low-cost electricity for KPCo's customers."

a. Based on currently available information, provide the average cost per kWh of electricity produced by Unit 2 and the "as of" date.

b. Provide the projected average cost per kWh of electricity produced by Unit 2 once the retrofits are completed in 2016.

RESPONSE

a. Total cost cannot be accurately calculated at the unit level. The variable production cost per kWh of electricity produced by Big Sandy Unit 2 over the December 2010 through November 2011 time period is 3.17 cents / kWh.

b. Total cost cannot be accurately calculated at the unit level. The variable production cost per kWh of electricity produced by Big Sandy Unit 2 in 2016 once the retrofits are completed is 4.15 cents/kWh under Fleet Transition - CSAPR(Base) commodity pricing.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Explain how Kentucky Power plans to meet the Hazardous Air Pollutants Rule as it relates to mercury, HCL, SO_3, and other pollutants.

RESPONSE

Kentucky Power currently plans to meet mercury and other hazardous air pollutants (HAPS) requirements through the installation of a Dry Flue Gas Desulfurization (DFGD) system with baghouse on Big Sandy Unit 2, and the retirement of Big Sandy Unit 1. The final Mercury and Air Toxics Standards (MATS) rule does not include SO_3.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Provide the expected service life of Big Sandy Unit 2 after the FGD upgrade.

RESPONSE

With appropriate ongoing maintenance and prudent and timely capital investment, the expected service life of Big Sandy Unit 2 could approach 70 years, or until at least 2040.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Regarding the environmental projects associated with the AEP Pool surplus companies as outlined in Exhibit JMM-1, provide the capital cost estimates for each of those projects.

RESPONSE

Please refer to Exhibit LPM-6 in the direct testimony of Company witness Munsey for the capital costs and estimates related to the environmental projects associated with the AEP Pool Surplus Companies outlined in Exhibit JMM-1.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 8 of the Direct Testimony of Lila P. Munsey ("Munsey Testimony"), lines 6-8. It states, "[the environmental projects being installed on Ohio Power Plants (OPCo) and Indiana and Michigan Company (I&M) plants could increase the environmental charges to KPCo."

a. Describe how the fixed and variable costs of these projects will be passed on to Kentucky Power's ratepayers.

b. Explain how the pass through of these costs is expected to change if the existing Pool Agreement is terminated.

RESPONSE

a. All environmental projects must be approved by this Commission before they can be added to the tariff. Once approved, the charges will flow through the surcharge in the same fashion as other OPCo and I&M currently recovered projects.

b. Please refer to the Company's response to KPSC 1-59b.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to page 9 of the Munsey Testimony, lines 12-1 9, where four projects at other AEP facilities that have already been placed in service are identified. Kentucky Power is requesting to incorporate the costs associated with these projects into the environmental surcharge report for inclusion in its environmental surcharge. Explain why these projects have not been previously incorporated into Kentucky Power's environmental surcharge.

RESPONSE

In order to be able to include new projects in the monthly surcharge, a filing must be made and the projects approved by the Commission. These projects were not yet in-service when Kentucky Power's environmental compliance plan was last amended.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to page 12 of the Munsey Testimony, lines 3-4. It states that the "Company's utility plant 15-year depreciation rate of 6.67%" was used. Provide the basis of the 15-year depreciation rate and explain whether this depreciation rate has been previously approved by the Commission.

RESPONSE

The 15-year depreciation rate is a calculated rate based on depreciating 100% of the plant within 15 years or 6.67% per year. The Company is unaware of any Commission approval of such a rate.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

For the capital costs imbedded in the costs of the Big Sandy Unit 2 FGD system in Exhibit LPM-1, provide a breakdown of the cost for the major components in the system in total dollar amounts and in dollars per kW.

RESPONSE

The breakdown of the total Big Sandy Unit 2 DFGD system of $940,300,067 ($1,175 per kW) is as follows:

Major Component	Cost	Cost per kW
DFGD Unit #2	$604,019,623	$755
DFGD Unit #2 Assoc	241,856,603	$302
DFGD Ash Haul Road	31,042,968	$39
DFGD Landfill	63,380,873	$79
Total	$940,300,067	$1,175

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1. The Preliminary Scrubber Analysis 2004-2006 amount is $15,212,425.

a. Confirm whether this amount pertains to preliminary scrubber analysis for the years 2004 to 2006.

b. Provide a breakdown of the $15,212,425 identifying the types of costs that have been incurred.

c. Explain whether this amount is for costs incurred for preliminary scrubber analysis only at the Big Sandy plant or if it includes any costs allocated to Kentucky Power by AEP of an AEP system-wide study of preliminary scrubber analysis.

d. If the answer to part a. of this Item is yes, explain whether any of this cost is applicable to the scrubber technology now proposed for Big Sandy Unit 2

RESPONSE

a. These costs were incurred during the 2004 to 2006 time frame for preliminary analysis using a wet scrubber technology.

b. The $15,212,425 is provided in two components:

	FGD Landfill	WFGD
Overheads	$ 111,254	$ 848,077
Internal Labor	$ 0	$ 81,918
Outside Services	$ 673,653	$ 5,279,572
Service Corp. Chrgs.	$ 225,202	$ 1,306,534
Material	$ 0	$ 5,966,590
Land Purchase	$ 630,018	$ 0
Other	$ 8,614	$ 80,993
Total	$1,648,741	$13,563,684

c. These costs were incurred specific to the Big Sandy Unit 2 generating unit.

d. The WFGD costs do not pertain to the specific scrubber technology being proposed in this filing, however, the costs are applicable for recovery as costs incurred in our total evaluation of the proper alternative and methodology to comply the various EPA regulations and the Consent Decree. The FGD Landfill costs can and will be used with the proposed DFGD technology.

WITNESS: Ranie K Wohnhas

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated January 13, 2012
Item No. 19
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1. Provide separate breakdowns of the proposed annual operation expense of $46.067 million and annual maintenance expense of $2.6 million which identifies the types of costs that make up these estimates.

RESPONSE

In millions of dollars (rounded).

	Operation	Maintenance	Total
Fixed	$ 3.55	$ 1.52	$ 5.07
Variable	$ 2.50	$ 1.07	$ 3.57
Consumable	$ 40.03	$ -	$ 40.03
Total	$ 46.08	$ 2.59	$ 48.67

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-2. The heading of column 4 is "Capital Costs of Associated Utility Revenues." In Kentucky Power's environmental surcharge filings, the environmental surcharge factor on ES Form 1.00 is determined by dividing the Net KY Retail Expense amount on line 8 by the KY Retail Revenue, from ES Form 3.30, line 9.

a. Associated Utilities Revenues is shown on line 3 of the top portion of ES FORM 3.30, but is not considered in the calculation of the environmental surcharge factor on ES Form 1.00. Explain why the exhibit includes a calculation to recover environmental costs applicable to Associated Utilities Revenues.

b. Based on the current approved methodology for environmental costs recovery in Kentucky Power's environmental surcharge report, explain whether environmental costs associated with Associated Utilities Revenues are recovered through base rates.

c. If the answer to part b. of this Item is yes, explain whether the monthly environmental surcharge base rates shown on the proposed tariff, on page 1 of Exhibit LPM-15, should be revised to include environmental costs applicable to both KY Retail Revenues and Associated Utility Revenues.

RESPONSE

a. The Capital Costs of Associated Utility Revenues in column 4 of Exhibit LPM-2, shows an estimate of the environmental costs for wholesale customers that per the March 31, 2003 Order in Case No. 2002-169 should not have been included in this filing. The revised affected exhibits are attached.

b. Yes, environmental costs associated with Associated Utilities Revenues are recovered through base rates.

c. No, the base rates as shown on the proposed tariff are correct and do not need to be adjusted. The Kentucky Retail Jurisdiction Allocation Factor is applied after removing the Base Period Revenue Requirement (BRR) from the total Current Period Revenue Requirement (CRR) and therefore it is only accounting for Kentucky Retail Revenues.

WITNESS: Lila P Munsey

Kentucky Power Company
Pollution Control Environmental Facilities
Annual Revenue Requirement
Associated with Big Sandy Plant

Line No. (1)	Description (2)	Capital Costs of KY Retail Revenues (3)
	Return on Rate Base	
1	Utility Plant Installed Net (Exhibit LPM-1, L5)	$ 955,512,492
2	Less: Accumulated Depreciation	$ 63,732,683
3	Less: Accumulated Deferred Income Taxes	$ 23,505,607
4	Net Utility Plant (L1- L2 - L3)	$ 868,274,202
5	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%
6	Annual Return on Rate Base (L4 X L5)	$ 92,818,512
	Operating Expenses	
7	Annual Depreciation (L2)	$ 63,732,683
8	Annual Property Tax Expense (Exhibit LPM-4, L5)	$ 1,337,670
9	Annual Non-Fuel O&M Expense (Exhibit LPM-1, L8)	$ 48,667,000
10	Total Operating Expenses (L7 + L8 + L9)	$ 113,737,353
11	Total Revenue Requirement Associated with BS Env. Facilities (L6 + L10)	$ 206,555,865
12	Annual Revenue Allocation Factor (Exhibit LPM-5, L15, C3 or C6)	78.91%
13	Subtotal (L11 X L12)	$ 162,993,233
14	KY Jurisdiction Revenue Allocation Factor (Exhibit LPM-5, L14, C3)	
15	Total KY Retail Revenue Requirement (L13 X L14)	$ 162,993,233
16	KY Jurisdiction 12-month Revenue (Exhibit LPM-5, L13, C3)	$ 569,593,245
17	Percent Change (L15 / L16)	28.62%

Revised Exhibit LPM-2

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs Associated with Allowance Inventory

Line No.	Description	Formula	KY Retail Rev Requirement
(1)	(2)	(3)	(4)
1	Estimated Monthly CSAPR SO2 Allowance Inventory	KIUC 1-20	$ 425,976
2	Estimated Monthly CSAPR NOx Allowance Inventory	KIUC 1-20	$ 2,053
3	Estimated Monthly CSAPR SO2 Consumption Expense	L11 / 12	$ 517,667
4	Estimated Monthly CSAPR NOx Consumption Expense	L12 / 12	$ (54,167)
5	Net Monthly Expenses (Consumption less Gains)	L3 + L4	$ 463,500
6	Cash Working Capital Allowance (in accordance with ES FORM 3.13)	L5 / 8	$ 57,938
7	Total Rate Base	L1 + L2 + L6	$ 485,967
8	*Annual Weighted Average Cost of Capital*	Exhibit LPM-3, L5, C8	10.69%
9	Return of Rate Base	L7 X L8	$ 51,950
10	Estimated Monthly CSAPR SO2 Consumption Expense	Wohnhas testimony	$ 6,212,000
11	Estimated Monthly CSAPR NOx Consumption Expense	Wohnhas testimony	$ (650,000)
12	Total Operating Expenses	L10 + L11	$ 5,562,000
13	Total Revenue Requirement	L9 + L12	$ 5,613,950
14	Annual Revenue Allocation Factor	Exhibit LPM-5, L15, C3	78.91%
15	Subtotal	L13 X L14	$ 4,429,968
16	KY Jurisdiction Revenue Allocation Factor	Exhibit LPM-5, L14, C3	98.91%
17	Total KY Retail Revenue Requirement	L15 X L16	$ 4,381,681
18	KY Jurisdiction 12-month Revenue	Exhibit LPM-5, L13, C3	$ 569,593,245
19	*Percent Change*	L17 / L18	0.77%

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs
Effect on Residential Customers

Line No.	Description	Formula	Annual Amount	Percent Increase
(1)	(2)	(3)	(5)	(6)
1	Annual Effect of New Environmental Pool Capacity Charges	Exhibit LPM-9, L14	$306,612	
2	KPCo's Share of Rockport	Exhibit LPM-12, L14	$480,780	
3	Total Environmental Cost	L1 + L2	$787,392	
4	KPCo's Average Retail Allocation for 12 months ended August 2011	Exhibit LPM-5, L.15, C3	78.91%	
5	Net Annual Impact on the Kentucky Retail Customers	L3 X L4	$621,331	0.10%
6	KY Retail Allowances	Exhibit LPM-13, L17, C4	$4,381,681	0.77%
7	KY Retail Revenue Requirement for Big Sandy Environmental Additions	Exhibit LPM-2, L15, C3	$162,993,233	28.62%
8	Total Environmental Projects in this Filing	L5 + L6 + L7	$167,996,245	29.49%
9	Billed Revenues for 12 months ended August 2011	Exhibit LPM-5, L13, C3	$569,593,245	
10	Percent Increase	L8 / L9	29.49%	
		Usage in kWh:	**1,000**	
11	Monthly Effect on a Residential Customers		$ 28.88	
12	Annualize		12	
13	**Annual Effect on a Residential Customers**	L11 X L12	$ 346.56	

Revised Exhibit LPM-14

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-6. Provide the calculation supporting the 29.89 percent in column 7 under the heading "OPCo or I&M Percentage."

RESPONSE

The 29.89% represents the percentage of Ohio Power Company's portion of Amos Plant (867 MW) divided by the total Amos Plant (2,900 MW). The amount that is recoverable is based on the 29.89% that Ohio Power owns and provides to the pool.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to page 4 of the Direct Testimony of Robert L. Walton ("Walton Testimony"), lines 17-19. It states, "[t]he Big Sandy Unit 2 FGD retrofit project will be executed using the same phased approach that has been successfully employed by AEP on many past projects. The phased approach begins with Phase1, which consists primarily of a feasibility study." Considering the $15,212,425 cost of the preliminary scrubber analysis of 2004-2006 on Exhibit LPM-1, explain whether more than one approach was considered for the proposal to construct a scrubber at Big Sandy Unit 2.

RESPONSE

Considering that the design basis for the Big Sandy Unit 2 scrubber was and remains 98% removal efficiency when burning a fuel with up to 4.5 lb/mmBTU SO_2, a wet scrubber was the only technology available in the 2004-2006 time frame that could meet the requirements. Therefore, the "approach" was focused on the selection of the most cost effective wet scrubber technology (spray tower design versus a jet bubbling reactor) and the optimum site configuration for the overall scrubber installation.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 5 of the Walton Testimony, lines 3-5. It states, "[s]ince 2004, AEP has implemented this phased approach in the installation of FGD systems on over 8,400 MW of generation and SCR ["Selective Catalytic Reduction"] systems on approximately 2,400 MW."

a. Provide the names of the affected generating units and the generating capability of each unit.

b. Provide the length of time to install each FGD from the start of Phase 1 to the in-service date of each FGD.

c. Provide the in-service date of each affected unit's FGD.

d. Provide the cost per kW for each affected unit's FGD.

e. Provide a copy of the project schedule for each unit in a form comparable to Exhibit RLW-1.

RESPONSE

a-d. Please see Attachment 1 to this response.

e. The project schedules were not compiled in the same form as Exhibit RLW-1 for the past FGD projects. Please see Attachments 2 through 9 for schedules that are readily available.

WITNESS: Robert L Walton

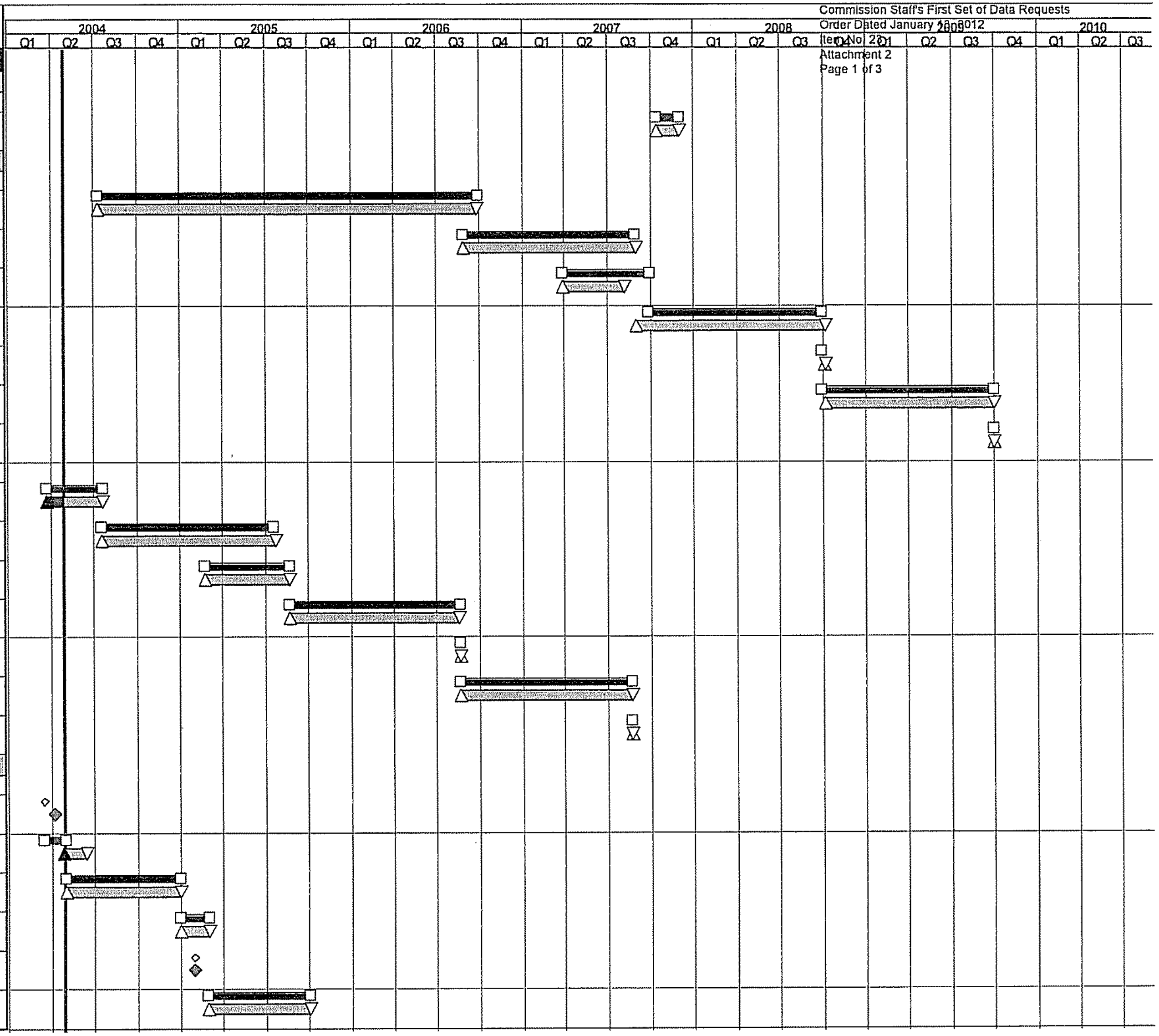
2004-2011 FGD Generation Projects

Project	Length	$/kw	MW	Phase I	Phase I (4)	Phase IIb	Actual	FGD In Service
		(FGD only)		($MM's)	($MM's)	($MM's)	($MM's)	
AM U1 FGD / Assoc / Landfill	78 months	385	800	255	306	250	308	2011
AM U2 FGD / Assoc / Landfill	67 months	385	800	255	306	250	308	2010
AM U3 FGD / Assoc / Landfill	56 months	568	1,300	462	554	569	739	2009
CD U1 FGD / Assoc / Landfill	54 months	513	600	309	371	329	308	2008
CV U4 FGD / SCR / Assoc / Landfill (3)	58 months	649	780	531	637	536	506	2009
ML U1 FGD / SCR / Assoc	59 months	668	800	401	481	444	534	2007
ML U2 FGD / SCR / Assoc	52 months	644	800	401	481	438	515	2006
MT FGD / Assoc / Landfill	44 months	443	1,300	394	473	539	576	2007
CD U2 FGD / Assoc	53 months	429	600	307	307	307	257	2008
CD U3 FGD / Assoc (2)	100 months	756	635	510	510	510	480	2012

Notes:
(1). Dollars amounts are total dollars including overheads and AFUDC.
(2). Actual cost is estimate, projects not yet in service
(3). CV U4-6 Landfill project is still in progress, Actuals represent only spent to date through Dec 2011.
(4). These Phase I estimates contain a 20% contingency allocation for comparative purposes to the Big Sandy Unit 2 Estimate

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated January [illegible] 2012
Item No. 2[illegible]
Attachment 2
Page 1 of 3

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Amos Plant Unit 3					
Scheduled Outages					
Level 2 Subset Activities					
AM3_9335	2007 GBIR Unit 3	15OCT07*	01DEC07	15OCT07*	01DEC07
FGD Landfill					
New Landfill					
AM123C0100	Initiate Siting Study & Secure Land	12JUL04*	25SEP06	12JUL04*	27SEP06
AM123C0200	Design Landfill	28AUG06*	30AUG07	28AUG06	28AUG07
AM123C0300	Prepare & Submit Application for Landfill Permit	28MAR07*	07AUG07	28MAR07	28SEP07
AM123C0400	Agency Review	31AUG07	05OCT08	28SEP07	29SEP08
AM123C0500	Receive Landfill Permit	05OCT08	05OCT08	29SEP08	29SEP08
AM123C0600	Construct Landfill	06OCT08	30SEP09	30SEP08	30SEP09
AM123C0800	Place Waste	30SEP09*	30SEP09	30SEP09	30SEP09
Phase C					
AM123N0100	Evaluate Existing Landfill	24MAR04A	19JUL04	24MAR04	19JUL04
AM123N0200	Design Landfill	19JUL04	23JUL05	19JUL04	19JUL05
AM123N0300	Prepare & Submit Application for Landfill Permit	24FEB05*	22AUG05	24FEB05	22AUG05
AM123N0400	Agency Review	22AUG05*	17AUG06	22AUG05	21AUG06
AM123N0500	Receive Landfill Permit	21AUG06*	21AUG06	21AUG06	21AUG06
AM123N0600	Construct Landfill	21AUG06*	20AUG07	21AUG06	20AUG07
AM123N0800	Place Waste	21AUG07*	21AUG07	21AUG07	21AUG07
Flue Gas Desulfurization					
Level 2 Subset Activities					
AM3_9349	Initiate CI for Phase I		07APR04A		15MAR04*
AM3_9350	Route CI for Approval	27APR04A	13JUN04	15MAR04*	01MAY04
AM3_9351	Phase 1 E&D	01MAY04*	31DEC04	01MAY04*	31DEC04
AM3_9298	Phase 2 CI Route & Approval	01JAN05*	01MAR05	01JAN05*	01MAR05
AM3_9301	Selection of OEM		28JAN05*		28JAN05*
AM3_9299	Phase 2 FGD E&D	01MAR05*	01OCT05	01MAR05*	01OCT05



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Finish Date	16OCT10
Data Date	29APR04
Run Date	30APR04 15:08

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Sheet 1A of 3B

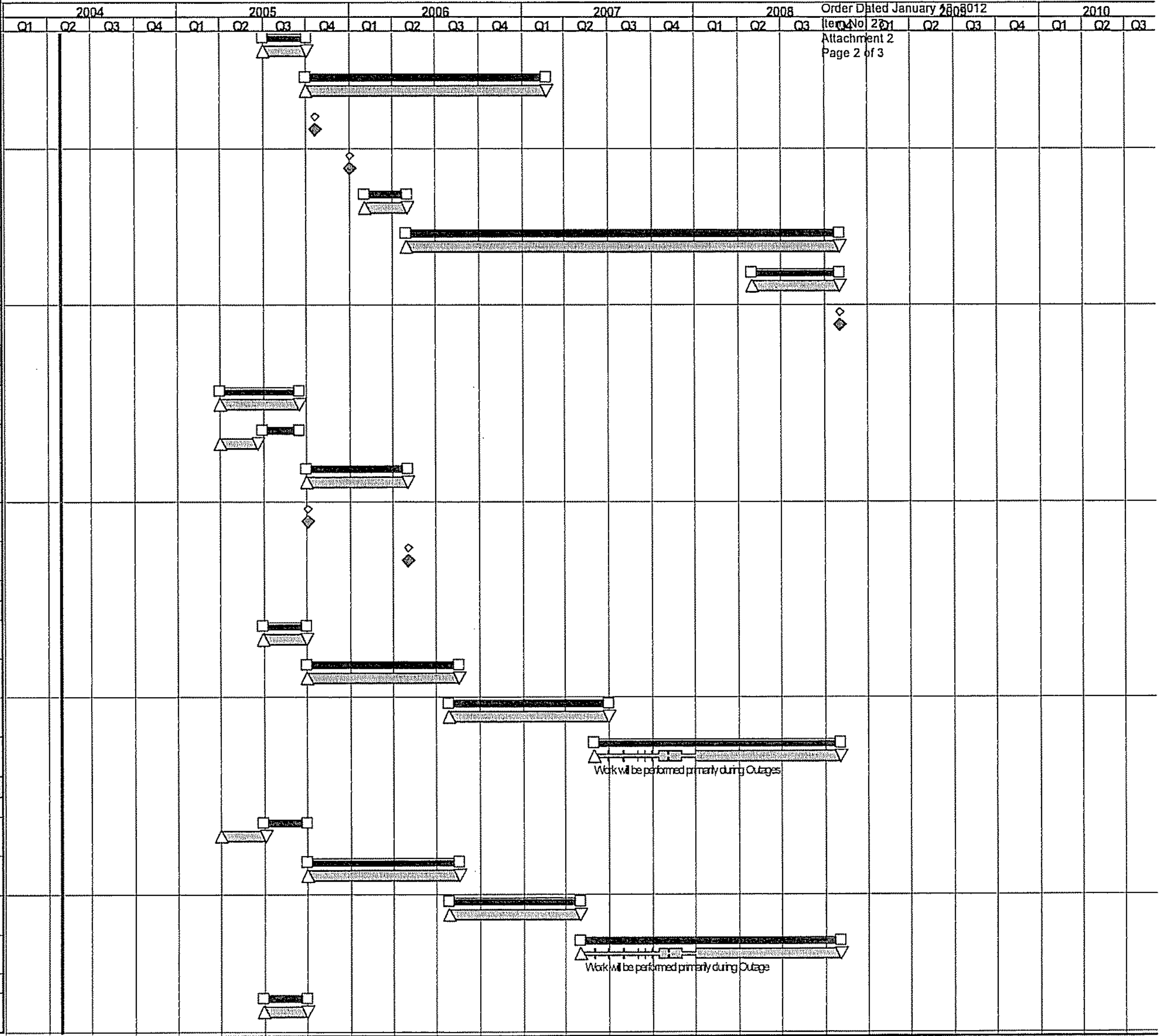
AEP
Environmental Projects Summary
Amos Unit 3

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
AM3_9320	Phase 3 CI Route & Approval	01JUL05*	01OCT05	01JUL05*	01OCT05
AM3_9323	Phase 3 FGD E&D	01OCT05*	22FEB07	01OCT05*	22FEB07
AM3_9318	Selection of Construction Manager		19OCT05*		19OCT05*
AM3_9321	Selection of FGD Constructor		01JAN06*		01JAN06*
AM3_9326	Relocations	01FEB06*	01MAY06	01FEB06*	01MAY06
AM3_9330	FGD Construction	01MAY06*	01NOV08	01MAY06*	01NOV08
AM3_9295	FGD Commissioning	01MAY08*	01NOV08	01MAY08*	01NOV08
AM3_9339	Initial FGD Operation		01NOV08*		01NOV08*
Air Permitting					
Level 2 Subset Activities					
AM3_9302	Perform Ambient Air Quality Modeling	01APR05*	15SEP05	01APR05*	15SEP05
AM3_9303	Prepare Air Permit Application	01APR05	18JUN05	29JUN05	15SEP05
AM3_9316	Agency Review	01OCT05*	01MAY06	01OCT05*	01MAY06
AM3_9317	Submit Air Permit Application		01OCT05*		01OCT05*
AM3_9329	Receive PTI & Commence Major Construction		01MAY06*		01MAY06*
Balanced Draft					
Level 2 Subset Activities					
AM3_9306	Release A/E to Commence Balanced Draft E&D	29JUN05*	30SEP05	29JUN05*	30SEP05
AM3_9310	AE / OEM Detailed Balanced Draft E&D	01OCT05*	18AUG06	01OCT05*	18AUG06
AM3_9324	Procure Balanced Draft Materials	28JUL06*	01JUL07	28JUL06*	01JUL07
AM3_9328	Perform Balanced Draft Modifications	31MAY07*	01NOV08	31MAY07*	01NOV08
Boiler Modifications					
Slag Control Devices					
AM3_9304	Release A/E for Slag Control Device E&D	01APR05	03JUL05	29JUN05	30SEP05
AM3_9348	Perform Detailed Slag Control	01OCT05*	18AUG06	01OCT05*	18AUG06
AM3_9311	Procure Slag Control Materials	28JUL06*	01MAY07	28JUL06*	01MAY07
AM3_9327	Install Slag Control Devices	01MAY07*	01NOV08	01MAY07*	01NOV08
Superheat Slag Monitoring System					
AM3_9305	Release A/E for Slag Monitoring E&D for CI	29JUN05*	30SEP05	29JUN05*	30SEP05



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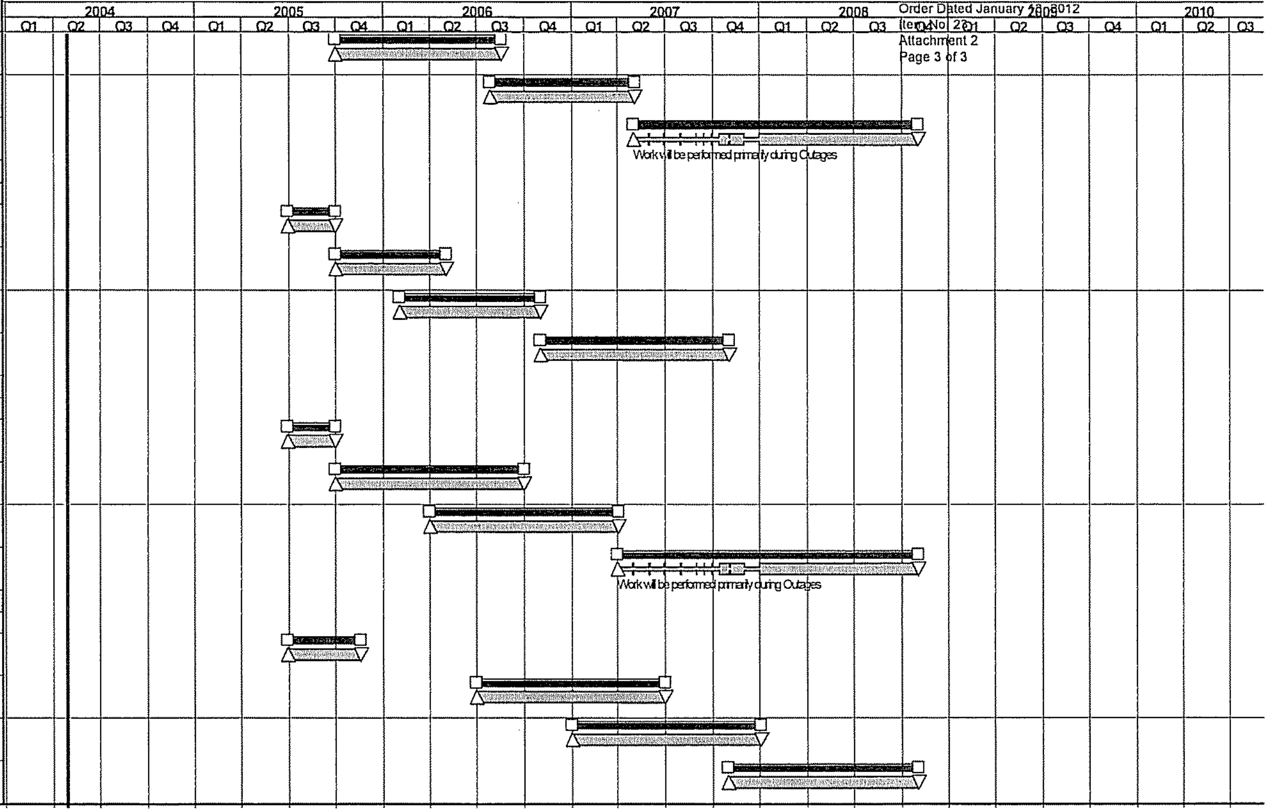
AEP
Environmental Projects Summary
Amos Unit 3

AEP AMERICAN® ELECTRIC POWER

Marian Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
AM3_9313	Perform Detailed Slag Monitoring E&D	01OCT05*	18AUG06	01OCT05*	18AUG06
AM3_9319	Procure Slag Monitoring Materials	28JUL06*	02MAY07	28JUL06*	02MAY07
AM3_9293	Install Slag Monitoring Devices	01MAY07*	01NOV08	01MAY07*	01NOV08
Coal Blending					
Level 2 Subset Activities					
AM3_9308	Release A/E to Evaluate Requirements	29JUN05	30SEP05	29JUN05	30SEP05
AM3_9315	Perform Detailed Coal Blending E&D	01OCT05*	01MAY06	01OCT05*	01MAY06
AM3_9325	Procure Coal Blending Materials	02FEB06*	01NOV06	02FEB06*	01NOV06
AM3_9337	Install Coal Blending Equipment	01NOV06*	01NOV07	01NOV06*	01NOV07
Control Modernization					
Level 2 Subset Activities					
AM3_9307	Release A/E to E/D Control System Modernization	29JUN05	29SEP05	29JUN05	29SEP05
AM3_9314	Perform Detailed Control Modernization E&D	01OCT05*	01OCT06	01OCT05*	01OCT06
AM3_9331	Procure Control System Equipment	01APR06*	01APR07	01APR06*	01APR07
AM3_9332	Install Control Modernization Modifications	01APR07*	01NOV08	01APR07*	01NOV08
SO3 Mitigation					
Level 2 Subset Activities					
AM3_9333	Release A/E for SO3 Mitigation E&D for CI	29JUN05*	18NOV05	29JUN05*	18NOV05
AM3_9334	SO3 Mitigation Engineering and Design	01JUL06*	01JUL07	01JUL06*	01JUL07
AM3_9340	Procure SO3 Mitigaton Equipment	01JAN07*	01JAN08	01JAN07*	01JAN08
AM3_9343	Install SO3 Mitigation System	01NOV07*	01NOV08	01NOV07*	01NOV08



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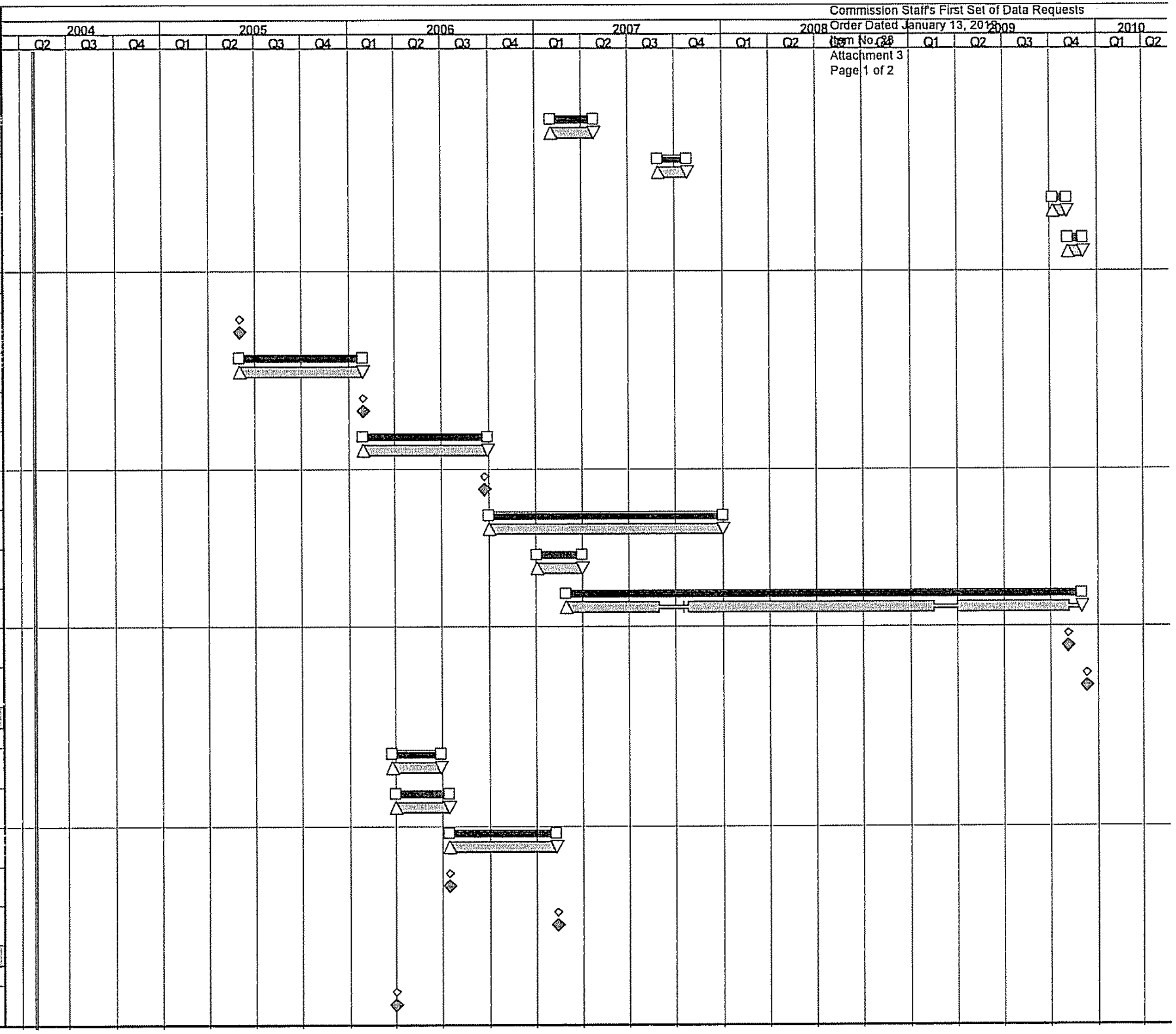
AEP
Environmental Projects Summary
Amos Unit 3

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Amos Plant Unit 1 & 2					
Scheduled Outages					
Level 2 Subset Activities					
A1_1001	2007 GBIR Unit 2	01FEB07*	26APR07	01FEB07*	26APR07
A1_9118	2007 GBIR Unit 1	30AUG07*	25OCT07	30AUG07*	25OCT07
A1_1002	FGD TIE-IN U2	07OCT09*	03NOV09	07OCT09*	03NOV09
A1_9134	FGD TIE-IN U1	06NOV09*	04DEC09	06NOV09*	04DEC09
Flue Gas Desulfurization					
Level 2 Subset Activities					
A1_9076	Phase I CI Approval		01JUN05*		01JUN05*
A1_9103	Phase I FGD , E&D	02JUN05	29JAN06	02JUN05	29JAN06
A1_9073	Phase 2 CI Approval		28JAN06*		28JAN06*
A1_9074	Phase 2 FGD E&D	29JAN06	28SEP06	29JAN06	28SEP06
A1_9099	Phase 3 CI Approval		22SEP06*		22SEP06*
A1_9101	Phase 3 FGD E&D	02OCT06*	31DEC07	02OCT06	31DEC07
A1_9106	Relocations	03JAN07*	31MAR07	03JAN07*	31MAR07
A1_9114	FGD Construction	01MAR07*	01DEC09	01MAR07*	01DEC09
A1_9130	Initial FGD Operation Unit 1		02NOV09*		02NOV09*
A1_9135	Initial FGD Operation Unit 2		10DEC09*		10DEC09*
Air Permitting					
Level 2 Subset Activities					
A1_9079	Perform Ambient Air Quality Modeling	24MAR06*	28JUN06	24MAR06*	28JUN06
A1_9080	Prepare Air Permit Application	31MAR06*	14JUL06	31MAR06*	14JUL06
A1_9095	Agency Review	14JUL06*	06FEB07	14JUL06*	06FEB07
A1_9096	Submit Air Permit Application		14JUL06*		14JUL06*
A1_9113	Receive PTI & Commence Major Construction		09FEB07*		09FEB07*
Balanced Draft					
Level 2 Subset Activities					
A1_9083	Release A/E to Commence Balanced Draft E&D		30MAR06*		30MAR06*



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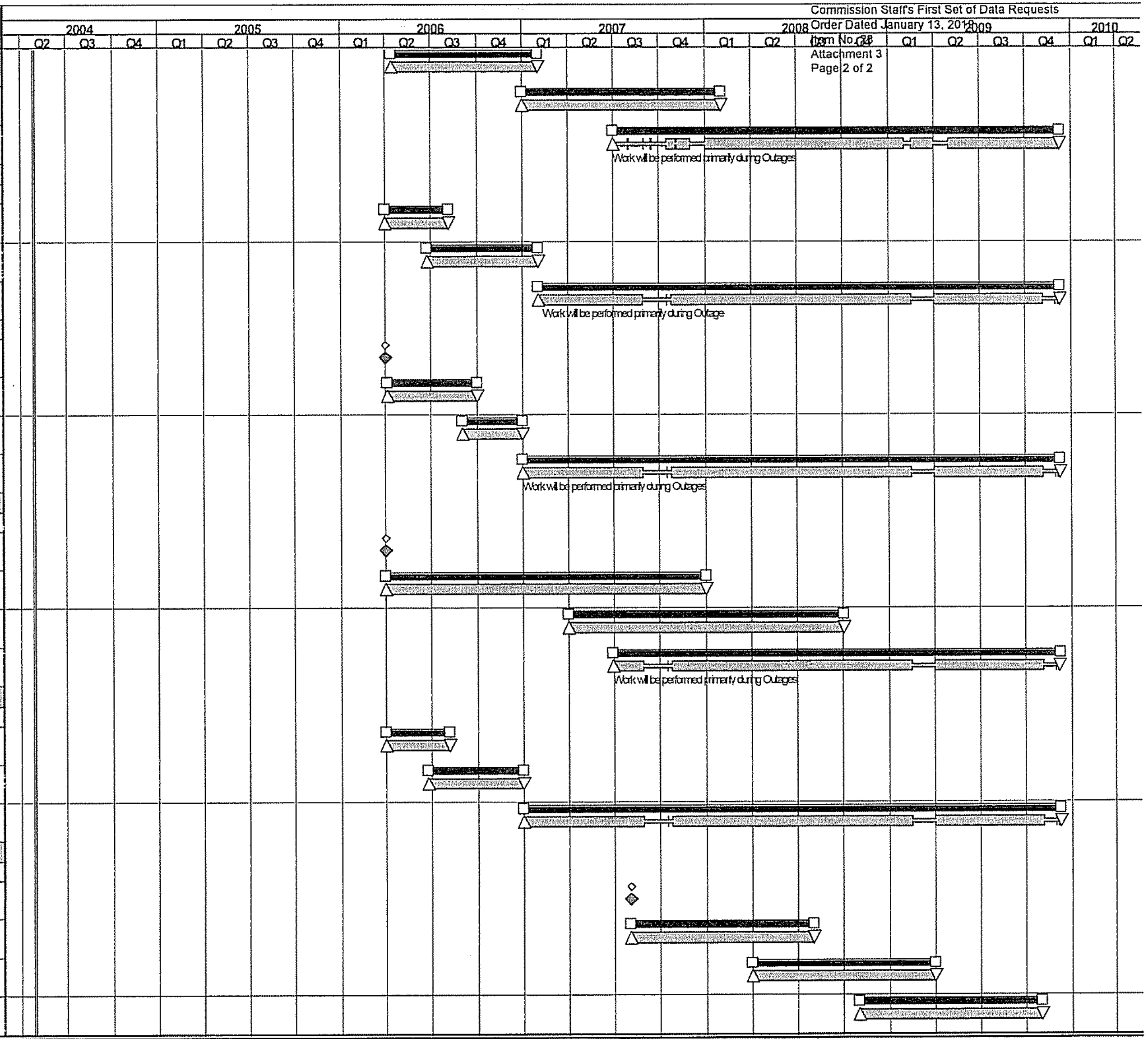
AEP
Environmental Projects Summary
Amos 1 & 2

AEP AMERICAN ELECTRIC POWER®

Marian Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
A1_9087	AE / OEM Detailed Balanced Draft E&D	15APR06*	01FEB07	15APR06*	01FEB07
A1_9088	Procure Balanced Draft Materials	01JAN07*	31JAN08	01JAN07*	31JAN08
A1_9109	Perform Balanced Draft Modifications	01JUL07*	10DEC09	01JUL07*	10DEC09
Boiler Modifications					
Slag Control Devices					
A1_9081	Release A/E for Slag Control Device E&D	31MAR06	05AUG06	31MAR06	05AUG06
A1_9089	Procure Slag Control Materials	24JUN06*	01FEB07	24JUN06*	01FEB07
A1_9107	Install Slag Control Devices	01FEB07*	10DEC09	01FEB07*	10DEC09
Superheat Slag Monitoring System					
A1_9082	Release A/E for Slag Monitoring E&D for CI		31MAR06*		31MAR06*
A1_9091	Perform Detailed Slag Monitoring E&D	06APR06*	01OCT06	06APR06*	01OCT06
A1_9098	Procure Slag Monitoring Materials	01SEP06*	31DEC06	01SEP06*	31DEC06
A1_9111	Install Slag Monitoring Devices	01JAN07*	10DEC09	01JAN07*	10DEC09
Control Modemization					
Level 2 Subset Activities					
A1_9084	Release A/E to E/D Control System Modemization		31MAR06*		31MAR06*
A1_9092	Perform Detailed Control Modemization E&D	01APR06*	01JAN08	01APR06*	01JAN08
A1_9115	Procure Control System Equipment	01APR07*	02OCT08	01APR07*	02OCT08
A1_9116	Install Control Modemization Modifications	30JUN07*	08DEC09	30JUN07*	09DEC09
Furnace Arch					
Level 2 Subset Activities					
A1_9086	Engineering & Design	01APR06*	05AUG06	01APR06*	05AUG06
A1_9090	Procurement	24JUN06	31DEC06	24JUN06	31DEC06
A1_9112	Installation (Outage Driven)	01JAN07*	10DEC09	01JAN07*	10DEC09
SO3 Mitigation					
Level 2 Subset Activities					
A1_9075	Release A/E for SO3 Mitigation E&D for CI		01AUG07*		01AUG07*
A1_9094	SO3 Mitigation Engineering and Design	02AUG07	01AUG08	02AUG07	01AUG08
A1_9117	Procure SO3 Mitigaton Equipment	01APR08*	01APR09	01APR08*	01APR09
A1_9121	Install SO3 Mitigation System	01NOV08*	01NOV09	01NOV08*	01NOV09



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Finish Date	16OCT10
Data Date	29APR04
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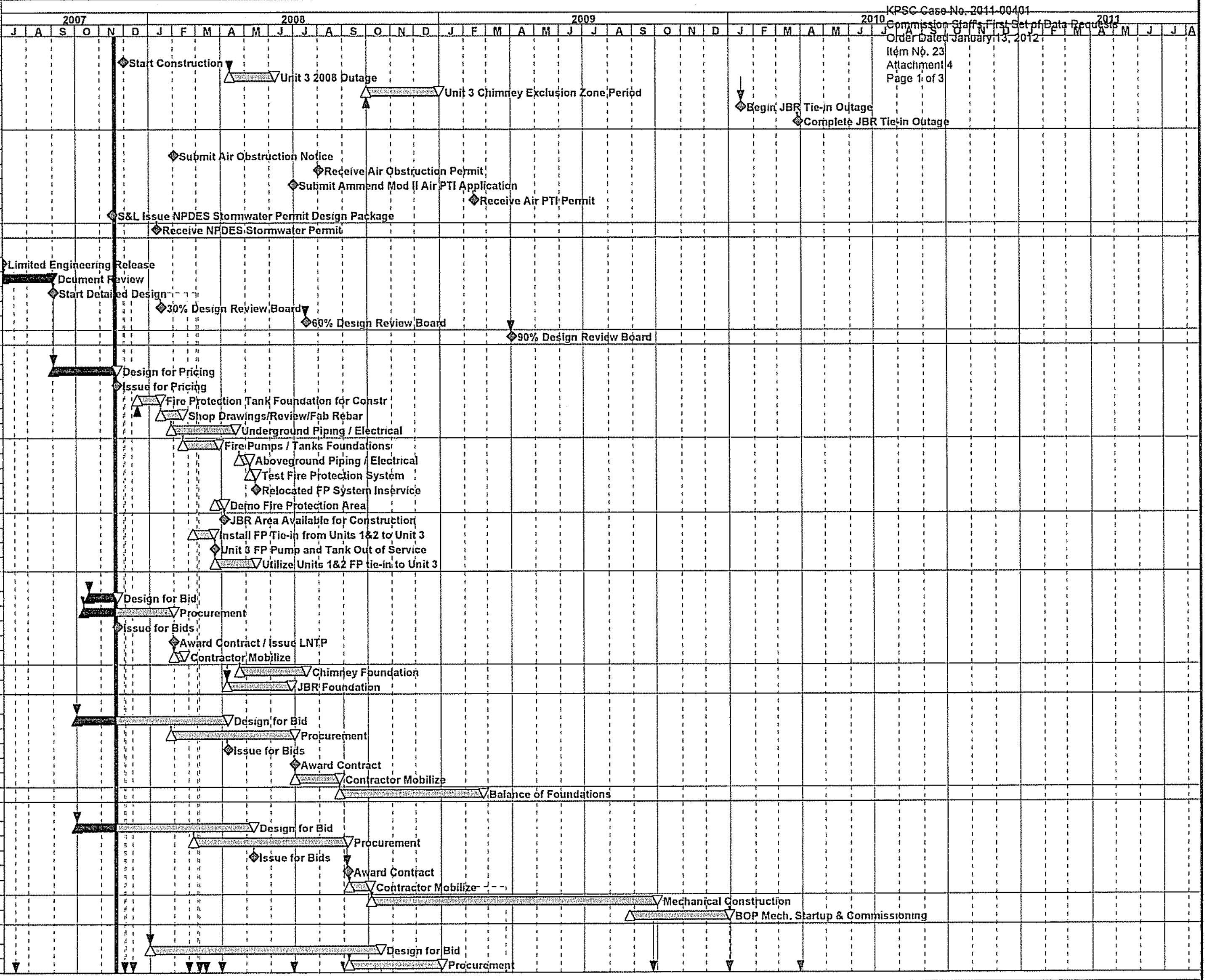
AEP
Environmental Projects Summary
Amos 1 & 2

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Project Milestones				
MS10	Start Construction	0	01DEC07*	
MS20	Unit 3 2008 Outage	57	13APR08	08JUN08
MS30	Unit 3 Chimney Exclusion Zone Period	66	01OCT08	31DEC08
MS40	Begin JBR Tie-in Outage	0	17JAN10	
MS50	Complete JBR Tie-in Outage	0		28MAR10
Critical Permits				
P100	Submit Air Obstruction Notice	0		01FEB08*
P110	Receive Air Obstruction Permit	0		01AUG08
P120	Submit Ammend Mod II Air PTI Application	0		01JUL08*
P130	Receive Air PTI Permit	0		13FEB09
P140	S&L Issue NPDES Stormwater Permit Design	0		16NOV07A
P150	Receive NPDES Stormwater Permit	0		11JAN08
Engineering Release / Design Review Boards				
10	Limited Engineering Release	0		29JUN07A
20	Dcument Review	45	02JUL07A	31AUG07A
30	Start Detailed Design	0	03SEP07A	
40	30% Design Review Board	0		16JAN08
50	60% Design Review Board	0		16JUL08
60	90% Design Review Board	0		01APR09
Fire Protection and Other Equipment Relocation				
100	Design for Pricing	110	03SEP07A	21NOV07
140	Issue for Pricing	0		21NOV07
200	Fire Protection Tank Foundation for Constr	21	17DEC07	14JAN08
285	Shop Drawings/Review/Fab Rebar	20	15JAN08	11FEB08
290	Underground Piping / Electrical	59	29JAN08	18APR08
291	Fire Pumps / Tanks Foundations	33	13FEB08	28MAR08
292	Aboveground Piping / Electrical	10	23APR08	06MAY08
293	Test Fire Protection System	5	07MAY08	13MAY08
294	Relocated FP System Inservice	0		13MAY08
295	Demo Fire Protection Area	10	24MAR08*	04APR08
296	JBR Area Available for Construction	0		04APR08
FP20	Install FP Tie-in from Units 1&2 to Unit 3	20	25FEB08*	21MAR08
FP30	Unit 3 FP Pump and Tank Out of Service	0	24MAR08	
FP40	Utilize Units 1&2 FP tie-in to Unit 3	37	24MAR08	13MAY08
Substructure & UG - Chimney / JBR				
300	Design for Bid	58	17OCT07A	21NOV07
310	Procurement	118	10OCT07A	30JAN08
340	Issue for Bids	0		21NOV07
370	Award Contract / Issue LNTP	0		30JAN08
380	Contractor Mobilize	10	31JAN08	13FEB08
390	Chimney Foundation	60	23APR08	15JUL08
395	JBR Foundation	60	07APR08	27JUN08
Substructure & UG - Balance				
400	Design for Bid	136	01OCT07A	07APR08
410	Procurement	111	28JAN08	30JUN08
440	Issue for Bids	0		07APR08
470	Award Contract	0		30JUN08
480	Contractor Mobilize	40	01JUL08	25AUG08
490	Balance of Foundations	130	26AUG08	23FEB09
Mechanical Construction				
600	Design for Bid	160	01OCT07A	09MAY08
610	Procurement	140	25FEB08	05SEP08
640	Issue for Bids	0		09MAY08
670	Award Contract	0		05SEP08
680	Contractor Mobilize	20	08SEP08	03OCT08
690	Mechanical Construction	258	06OCT08	30SEP09
695	BOP Mech. Startup & Commissioning	89	27AUG09	29DEC09
Electrical Aboveground				
900	Design for Bid	209	01JAN08	17OCT08
910	Procurement	85	08SEP08	02JAN09



Start Date 01JUL07
Finish Date 25MAR11
Data Date 19NOV07
Run Date 19NOV07 17:09

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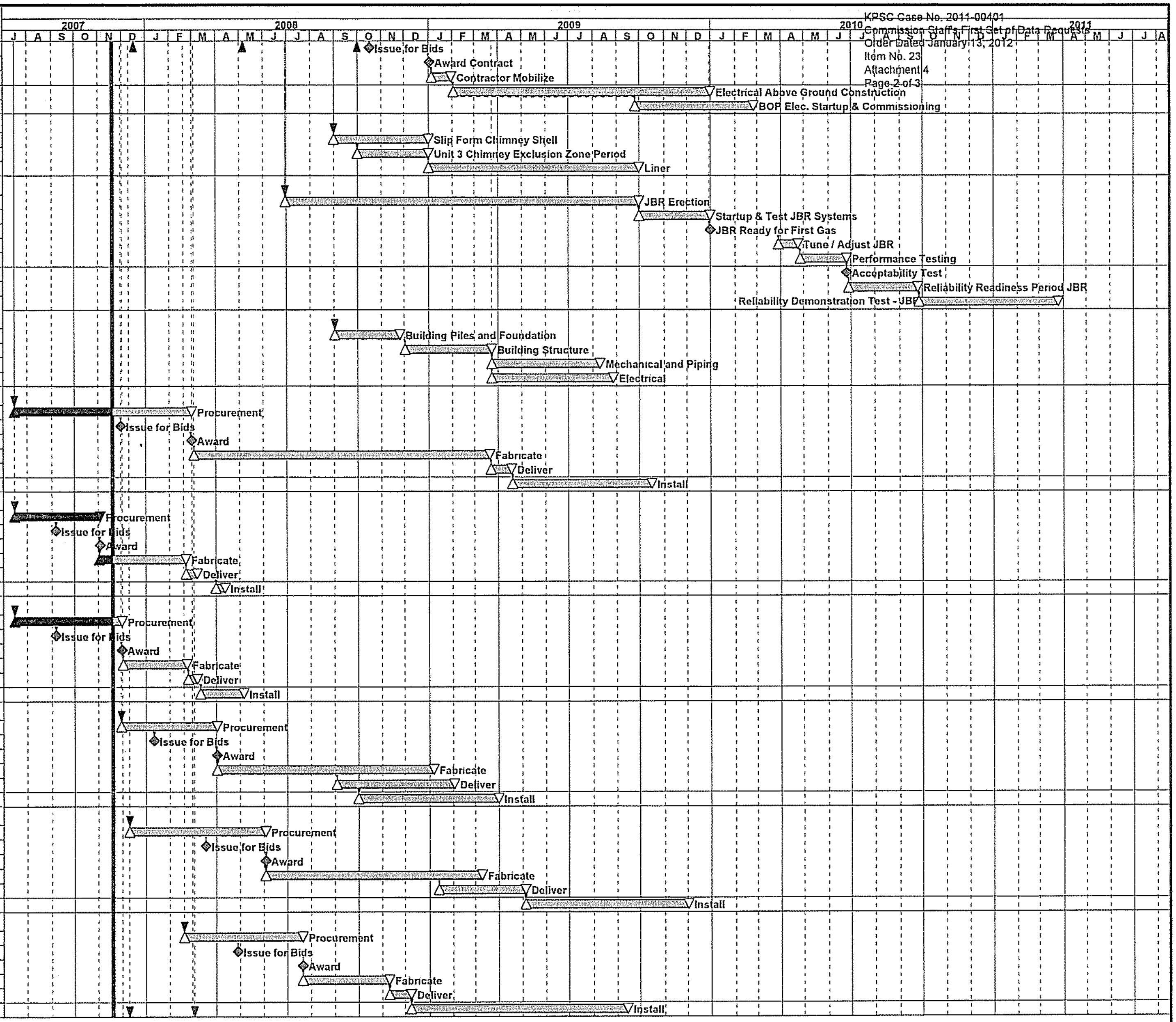
Level 1 Project Schedule
AEP
Cardinal Unit 3 FGD

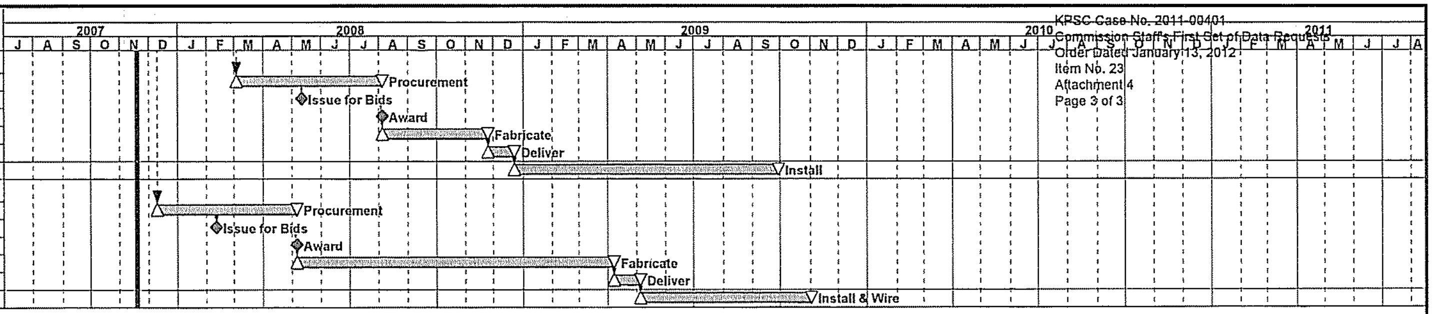
Sheet 1 of 3

Sargent & Lundy LLC

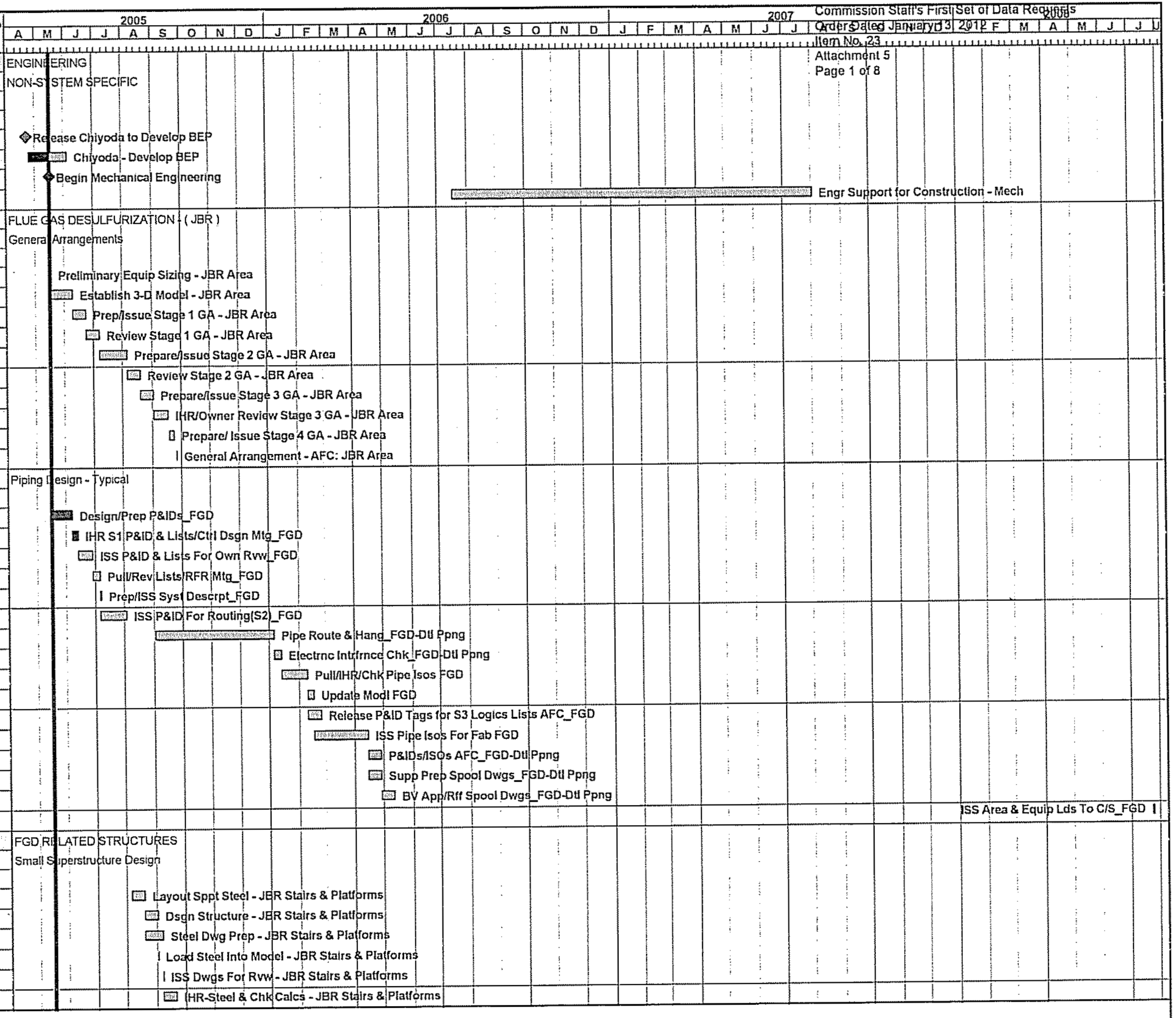
Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
940	Issue for Bids	0		17OCT08
970	Award Contract	0		02JAN09
980	Contractor Mobilize	20	05JAN09	30JAN09
990	Electrical Above Ground Construction	239	02FEB09	31DEC09
995	BOP Elec. Startup & Commissioning	110	25SEP09	25FEB10
Chimney				
1000	Slip Form Chimney Shell	88	01SEP08*	31DEC08
1005	Unit 3 Chimney Exclusion Zone Period	66	01OCT08	31DEC08
1010	Liner	195	01JAN09	30SEP09
JBR Construction				
1100	JBR Erection	327	30JUN08	29SEP09
1110	Startup & Test JBR Systems	66	30SEP09	30DEC09
1120	JBR Ready for First Gas	0		30DEC09
1130	Tune / Adjust JBR	20	29MAR10	23APR10
1140	Performance Testing	45	26APR10	25JUN10
1150	Acceptability Test	0		25JUN10
1160	Reliability Readiness Period JBR	65	28JUN10	24SEP10
1170	Reliability Demonstration Test - JBR	130	27SEP10	25MAR11
FGD Common Building Construction				
1200	Building Piles and Foundation	60	02SEP08	24NOV08
1210	Building Structure	80	02DEC08	23MAR09
1220	Mechanical and Piping	100	24MAR09	10AUG09
1230	Electrical	113	24MAR09	27AUG09
Procurement - ID Fans				
P05.10	Procurement	130	16JUL07A	29FEB08
P05.20	Issue for Bids	0	30NOV07	
P05.30	Award	0		29FEB08
P05.40	Fabricate	275	03MAR08	20MAR09
P05.50	Deliver	20	23MAR09	17APR09
P05.60	Install	130	20APR09	16OCT09
Procurement - Fire Protection Pumps				
P10.10	Procurement	75	16JUL07A	02NOV07A
P10.20	Issue for Bids	0	07SEP07A	
P10.30	Award	0		02NOV07A
P10.40	Fabricate	80	02NOV07A	21FEB08
P10.50	Deliver	11	22FEB08	07MAR08
P10.60	Install	10	31MAR08	11APR08
Procurement - Field Erected Tanks				
P15.10	Procurement	70	16JUL07A	30NOV07
P15.20	Issue for Bids	0	07SEP07A	
P15.30	Award	0		30NOV07
P15.40	Fabricate	60	03DEC07	22FEB08
P15.50	Deliver	10	25FEB08	07MAR08
P15.60	Install	40	12MAR08	06MAY08
Procurement - Structural Steel				
P20.10	Procurement	88	30NOV07	01APR08
P20.20	Issue for Bids	0	11JAN08	
P20.30	Award	0		01APR08
P20.40	Fabricate	200	02APR08	06JAN09
P20.50	Deliver	109	03SEP08	02FEB09
P20.60	Install	130	01OCT08	31MAR09
Procurement - Ductwork				
P25.10	Procurement	126	11DEC07	03JUN08
P25.20	Issue for Bids	0	18MAR08	
P25.30	Award	0		03JUN08
P25.40	Fabricate	200	04JUN08	10MAR09
P25.50	Deliver	80	14JAN09	05MAY09
P25.60	Install	150	06MAY09	01DEC09
Procurement - Fabricated FRP Pipe				
P30.10	Procurement	110	19FEB08	21JUL08
P30.20	Issue for Bids	0	28APR08	
P30.30	Award	0		21JUL08
P30.40	Fabricate	80	22JUL08	10NOV08
P30.50	Deliver	20	11NOV08	08DEC08
P30.60	Install	200	09DEC08	14SEP09



Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
Procurement - Carbon Steel Pipe				
P35.10	Procurement	110	04MAR08	04AUG08
P35.20	Issue for Bids	0	12MAY08	
P35.30	Award	0		04AUG08
P35.40	Fabricate	80	05AUG08	24NOV08
P35.50	Deliver	20	25NOV08	22DEC08
P35.60	Install	200	23DEC08	28SEP09
Procurement - DCS				
P45.10	Procurement	105	11DEC07	05MAY08
P45.20	Issue for Bids	0	11FEB08	
P45.30	Award	0		05MAY08
P45.40	Fabricate	240	06MAY08	06APR09
P45.50	Deliver	20	07APR09	04MAY09
P45.60	Install & Wire	130	05MAY09	02NOV09



Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
ENGINEERING						
NON-SYSTEM SPECIFIC						
OF00002-00	Release Chiyoda to Develop BEP	22APR05A		0		
OF000-05	Chiyoda - Develop BEP	25APR05A	03JUN05	36		
OF00002-10	Begin Mechanical Engineering	16MAY05		0	C	
OFCAAA2-97	Engr Support for Construction - Mech	17JUL06	01AUG07	262*	C	
FLUE GAS DESULFURIZATION - (JBR)						
General Arrangements						
OFCCC2-01	Preliminary Equip Sizing - JBR Area	17MAY05	17MAY05	1	C	
OFCCC2-02	Establish 3-D Model - JBR Area	18MAY05	08JUN05	15	C	
OFCCC2-07	Prep/Issue Stage 1 GA - JBR Area	09JUN05	22JUN05	10	C	
OFCCC2-12	Review Stage 1 GA - JBR Area	23JUN05	07JUL05	10	C	
OFCCC2-17	Prepare/Issue Stage 2 GA - JBR Area	08JUL05	04AUG05	20	C	
OFCCC2-22	Review Stage 2 GA - JBR Area	05AUG05	18AUG05	10	C	
OFCCC2-27	Prepare/Issue Stage 3 GA - JBR Area	19AUG05	01SEP05	10	C	
OFCCC2-32	IHR/Owner Review Stage 3 GA - JBR Area	02SEP05	16SEP05	10	C	
OFCCC2-37	Prepare/ Issue Stage 4 GA - JBR Area	19SEP05	23SEP05	5	C	
OFCCC2-99	General Arrangement - AFC: JBR Area	26SEP05	26SEP05	1	C	
Piping Design - Typical						
OFCCC2A01	Design/Prep P&IDs_FGD	16MAY05	06JUN05	15	C	
OFCCC2A11	IHR S1 P&ID & Lists/Ctrl Dsgn Mtg_FGD	07JUN05	13JUN05	5	C	
OFCCC2A10	ISS P&ID & Lists For Own Rvw_FGD	14JUN05	27JUN05	10	C	
OFCCC2A18	Pull/Rev Lists/RFR Mtg_FGD	28JUN05	05JUL05	5	C	
OFCCC2A99	Prep/ISS Syst Descrpt_FGD	06JUL05	07JUL05	2	C	
OFCCC2A15	ISS P&ID For Routing(S2)_FGD	06JUL05	02AUG05	20	C	
OFCCC2A26	Pipe Route & Hang_FGD-Dtl Ppng	02SEP05	05JAN06	80	C	
OFCCC2A32	Electrnc Intrfrnce Chk_FGD-Dtl Ppng	06JAN06	12JAN06	5	C	
OFCCC2A43	Pull/IHR/Chk Pipe Isos FGD	13JAN06	09FEB06	20	C	
OFCCC2A45	Update Modl FGD	10FEB06	16FEB06	5	C	
OFCCC2A16	Release P&ID Tags for S3 Logics Lists AFC_FGD	10FEB06	23FEB06	10	C	
OFCCC2A49	ISS Pipe Isos For Fab FGD	17FEB06	13APR06	40	C	
OFCCC2A59	P&IDs/ISOs AFC_FGD-Dtl Ppng	14APR06	27APR06	10	C	
OFCCC2A91	Supp Prep Spool Dwgs_FGD-Dtl Ppng	14APR06	27APR06	10	C	
OFCCC2A97	BV App/Rff Spool Dwgs_FGD-Dtl Ppng	28APR06	11MAY06	10	C	
OFCCC2A24	ISS Area & Equip Lds To C/S_FGD	24JUL08	24JUL08	1	C	
FGD RELATED STRUCTURES						
Small Superstructure Design						
OFCCC1A04	Layout Sppt Steel - JBR Stairs & Platforms	05AUG05	18AUG05	10	B	
OFCCC1A10	Dsgn Structure - JBR Stairs & Platforms	19AUG05	01SEP05	10	B	
OFCCC1A16	Steel Dwg Prep - JBR Stairs & Platforms	19AUG05	06SEP05	12	B	
OFCCC1A14	Load Steel Into Model - JBR Stairs & Platforms	02SEP05	02SEP05	1	B	
OFCCC1A22	ISS Dwgs For Rvw - JBR Stairs & Platforms	07SEP05	07SEP05	1	B	
OFCCC1A24	IHR-Steel & Chk Calcs - JBR Stairs & Platforms	08SEP05	21SEP05	10	B	



Data Date 16MAY05
Run Date 02MAY05 16:13

▨ Early Bar
▬ Progress Bar
■ Critical Activity

TEM2

Sheet 1 of 8

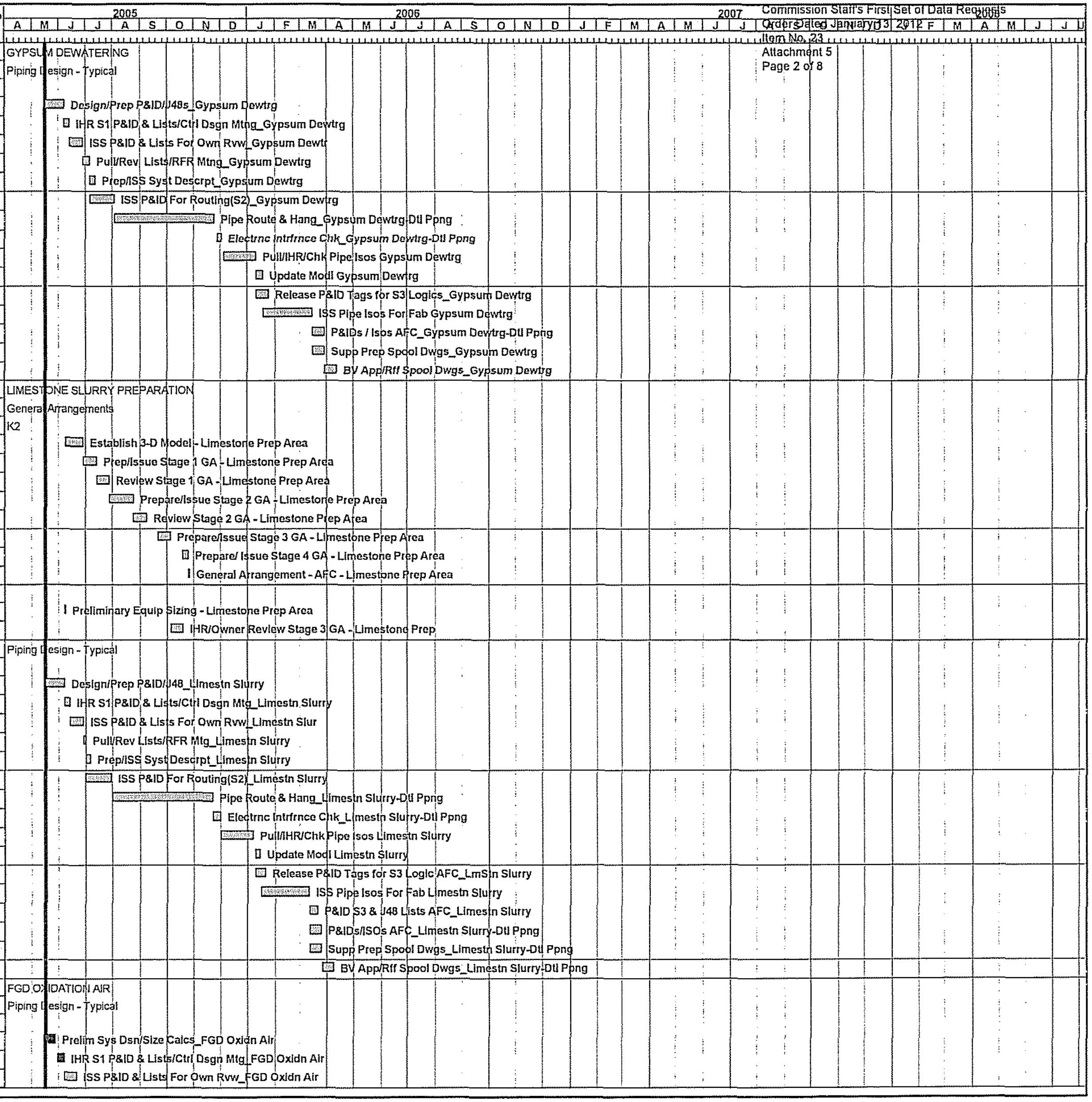
Black & Veatch

AEP Cardinal

FGD OEM Schedule

Date	Revision	Checked	Approved

Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
GYPSUM DEWATERING						
Piping Design - Typical						
OFASE2A01	Design/Prep P&ID/J48s_Gypsum Dewtrg	16MAY05	06JUN05	15	C	
OFASE2A11	IHR S1 P&ID & Lists/Ctrl Dsgn Mtng_Gypsum Dewtrg	07JUN05	13JUN05	5	C	
OFASE2A10	ISS P&ID & Lists For Own Rvw_Gypsum Dewtr	14JUN05	27JUN05	10	C	
OFASE2A18	Pull/Rev Lists/RFR Mtng_Gypsum Dewtrg	28JUN05	05JUL05	5	C	
OFASE2A99	Prep/ISS Syst Descrpt_Gypsum Dewtrg	06JUL05	12JUL05	5	C	
OFASE2A15	ISS P&ID For Routing(S2)_Gypsum Dewtrg	06JUL05	02AUG05	20	C	
OFASE2A26	Pipe Route & Hang_Gypsum Dewtrg-Dtl Ppng	03AUG05	23NOV05	80	C	
OFASE2A32	Electrnc Intrfrnce Chk_Gypsum Dewtrg-Dtl Ppng	28NOV05	02DEC05	5	C	
OFASE2A43	Pull/IHR/Chk Pipe Isos Gypsum Dewtrg	05DEC05	10JAN06	20	C	
OFASE2A45	Update Modl Gypsum Dewtrg	11JAN06	17JAN06	5	C	
OFASE2A16	Release P&ID Tags for S3 Logics_Gypsum Dewtrg	11JAN06	24JAN06	10	C	
OFASE2A49	ISS Pipe Isos For Fab Gypsum Dewtrg	18JAN06	14MAR06	40	C	
OFASE2A59	P&IDs / Isos AFC_Gypsum Dewtrg-Dtl Ppng	15MAR06	28MAR06	10	C	
OFASE2A91	Supp Prep Spool Dwgs_Gypsum Dewtrg	15MAR06	28MAR06	10	C	
OFASE2A97	BV App/Rlf Spool Dwgs_Gypsum Dewtrg	29MAR06	11APR06	10	C	
LIMESTONE SLURRY PREPARATION						
General Arrangements						
K2						
OFBMC2-02	Establish 3-D Model - Limestone Prep Area	08JUN05	28JUN05	15	C	
OFBMC2-07	Prep/Issue Stage 1 GA - Limestone Prep Area	29JUN05	13JUL05	10	C	
OFBMC2-12	Review Stage 1 GA - Limestone Prep Area	14JUL05	27JUL05	10	C	
OFBMC2-17	Prepare/Issue Stage 2 GA - Limestone Prep Area	28JUL05	24AUG05	20	C	
OFBMC2-22	Review Stage 2 GA - Limestone Prep Area	25AUG05	08SEP05	10	C	
OFBMC2-27	Prepare/Issue Stage 3 GA - Limestone Prep Area	21SEP05	04OCT05	10	C	
OFBMC2-37	Prepare/ Issue Stage 4 GA - Limestone Prep Area	19OCT05	25OCT05	5	C	
OFBMC2-99	General Arrangement - AFC - Limestone Prep Area	26OCT05	26OCT05	1	C	
OFBMC2-01	Preliminary Equip Sizing - Limestone Prep Area	07JUN05	07JUN05	1	C	
OFBMC2-32	IHR/Owner Review Stage 3 GA - Limestone Prep	05OCT05	18OCT05	10	C	
Piping Design - Typical						
OFBMC2A01	Design/Prep P&ID/J48_Limestn Slurry	16MAY05	06JUN05	15	C	
OFBMC2A11	IHR S1 P&ID & Lists/Ctrl Dsgn Mtg_Limestn Slurry	07JUN05	13JUN05	5	C	
OFBMC2A10	ISS P&ID & Lists For Own Rvw_Limestn Slur	14JUN05	27JUN05	10	C	
OFBMC2A18	Pull/Rev Lists/RFR Mtg_Limestn Slurry	28JUN05	30JUN05	3	C	
OFBMC2A99	Prep/ISS Syst Descrpt_Limestn Slurry	01JUL05	05JUL05	2	C	
OFBMC2A15	ISS P&ID For Routing(S2)_Limestn Slurry	01JUL05	29JUL05	20	C	
OFBMC2A26	Pipe Route & Hang_Limestn Slurry-Dtl Ppng	01AUG05	21NOV05	80	C	
OFBMC2A32	Electrnc Intrfrnce Chk_Limestn Slurry-Dtl Ppng	22NOV05	30NOV05	5	C	
OFBMC2A43	Pull/IHR/Chk Pipe Isos Limestn Slurry	01DEC05	06JAN06	20	C	
OFBMC2A45	Update Modl Limestn Slurry	09JAN06	13JAN06	5	C	
OFBMC2A16	Release P&ID Tags for S3 Logic AFC_LmStn Slurry	09JAN06	20JAN06	10	C	
OFBMC2A49	ISS Pipe Isos For Fab Limestn Slurry	16JAN06	10MAR06	40	C	
OFBMC2A19	P&ID S3 & J48 Lists AFC_Limestn Slurry	13MAR06	20MAR06	6	C	
OFBMC2A59	P&IDs/ISOs AFC_Limestn Slurry-Dtl Ppng	13MAR06	24MAR06	10	C	
OFBMC2A91	Supp Prep Spool Dwgs_Limestn Slurry-Dtl Ppng	13MAR06	24MAR06	10	C	
OFBMC2A97	BV App/Rlf Spool Dwgs_Limestn Slurry-Dtl Ppng	27MAR06	07APR06	10	C	
FGD OXIDATION AIR						
Piping Design - Typical						
OFCAD2A01	Prelim Sys Dsn/Size Calcs_FGD Oxidn Air	16MAY05	27MAY05	10	C	
OFCAD2A11	IHR S1 P&ID & Lists/Ctrl Dsgn Mtg_FGD Oxidn Air	31MAY05	06JUN05	5	C	
OFCAD2A10	ISS P&ID & Lists For Own Rvw_FGD Oxidn Air	07JUN05	20JUN05	10	C	



KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated January 3, 2012
Item No. 23
Attachment 5
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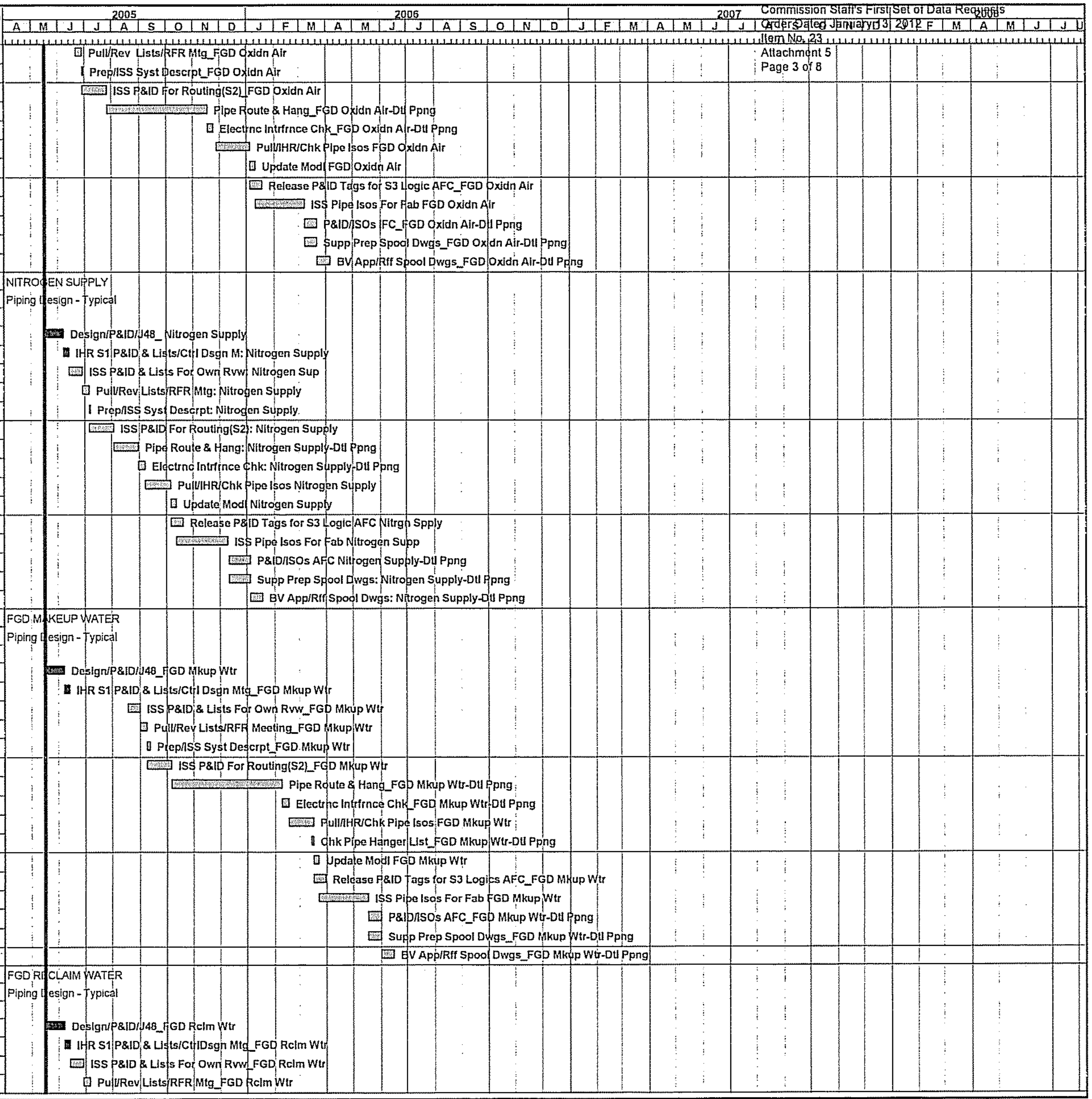
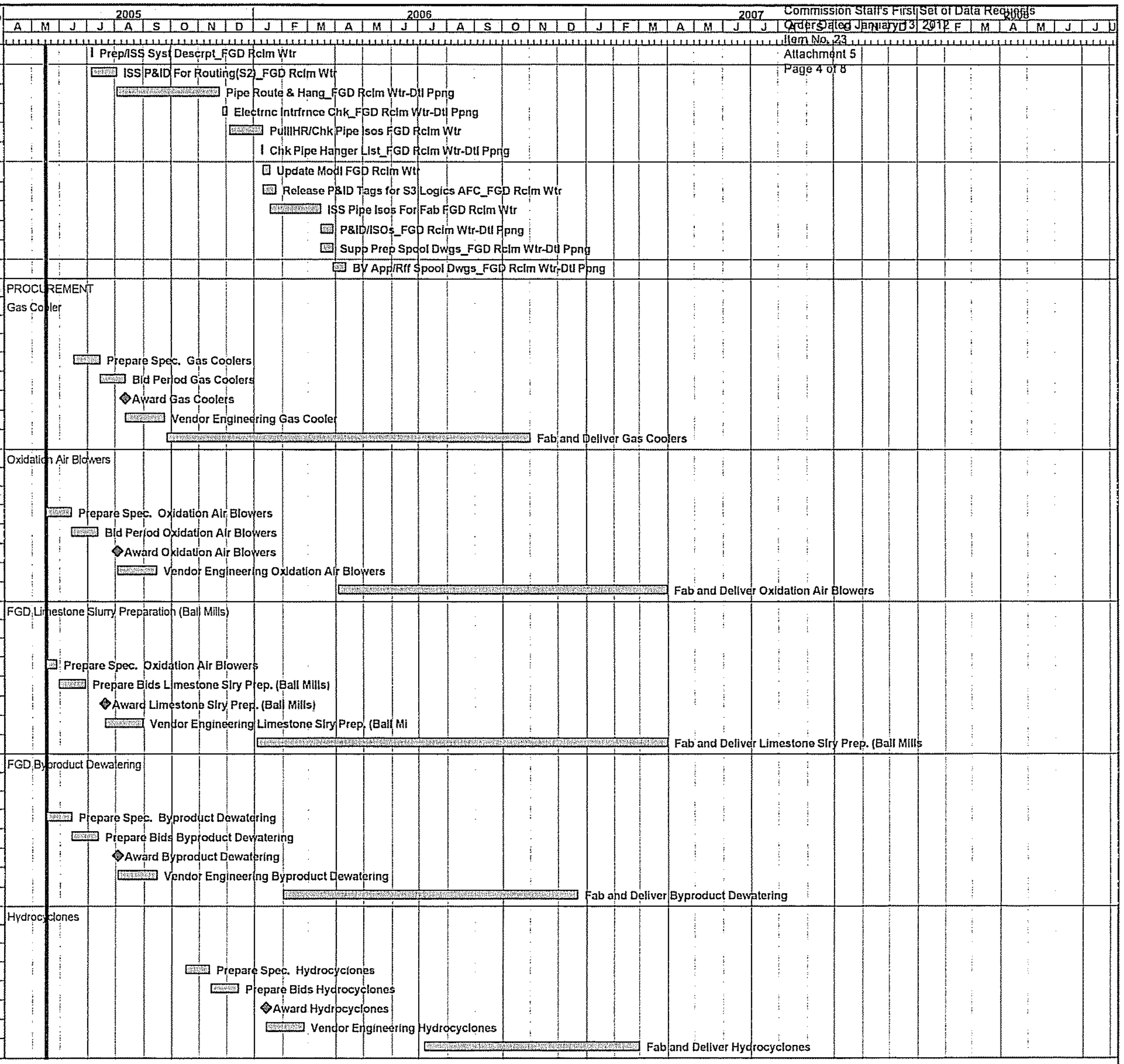
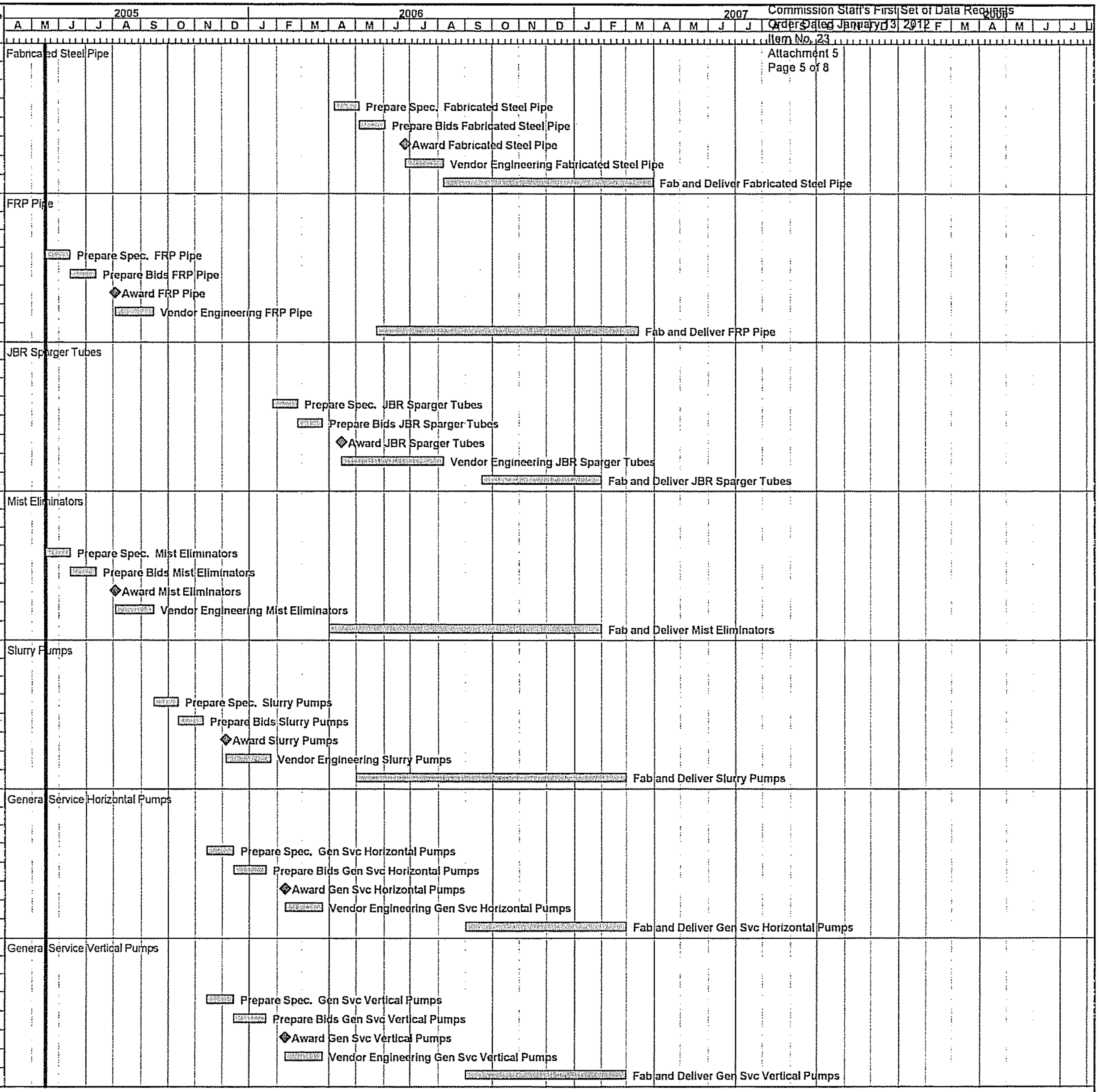
Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
OFCAD2A18	Pull/Rev Lists/RFR Mtg_FGD Oxidn Air	21JUN05	27JUN05	5	C	
OFCAD2A99	Prep/ISS Syst Descrpt_FGD Oxidn Air	28JUN05	29JUN05	2	C	
OFCAD2A15	ISS P&ID For Routing(S2)_FGD Oxidn Air	28JUN05	26JUL05	20	C	
OFCAD2A26	Pipe Route & Hang_FGD Oxidn Air-Dtl Ppng	27JUL05	16NOV05	80	C	
OFCAD2A32	Electrnc Intrfrnce Chk_FGD Oxidn Air-Dtl Ppng	17NOV05	23NOV05	5	C	
OFCAD2A43	Pull/IHR/Chk Pipe Isos FGD Oxidn Air	28NOV05	03JAN06	20	C	
OFCAD2A45	Update Modl FGD Oxidn Air	04JAN06	10JAN06	5	C	
OFCAD2A16	Release P&ID Tags for S3 Logic AFC_FGD Oxidn Air	04JAN06	17JAN06	10	C	
OFCAD2A49	ISS Pipe Isos For Fab FGD Oxidn Air	11JAN06	07MAR06	40	C	
OFCAD2A59	P&ID/ISOs IFC_FGD Oxidn Air-Dtl Ppng	08MAR06	21MAR06	10	C	
OFCAD2A91	Supp Prep Spool Dwgs_FGD Oxidn Air-Dtl Ppng	08MAR06	21MAR06	10	C	
OFCAD2A97	BV App/Rlf Spool Dwgs_FGD Oxidn Air-Dtl Ppng	22MAR06	04APR06	10	C	
NITROGEN SUPPLY						
Piping Design - Typical						
OFCGD2A01	Design/P&ID/J48_ Nitrogen Supply	16MAY05	06JUN05	15	C	
OFCGD2A11	IHR S1 P&ID & Lists/Ctrl Dsgn M: Nitrogen Supply	07JUN05	13JUN05	5	C	
OFCGD2A10	ISS P&ID & Lists For Own Rvw: Nitrogen Sup	14JUN05	27JUN05	10	C	
OFCGD2A18	Pull/Rev Lists/RFR Mtg: Nitrogen Supply	28JUN05	05JUL05	5	C	
OFCGD2A99	Prep/ISS Syst Descrpt: Nitrogen Supply	06JUL05	07JUL05	2	C	
OFCGD2A15	ISS P&ID For Routing(S2): Nitrogen Supply	06JUL05	02AUG05	20	C	
OFCGD2A26	Pipe Route & Hang: Nitrogen Supply-Dtl Ppng	03AUG05	30AUG05	20	C	
OFCGD2A32	Electrnc Intrfrnce Chk: Nitrogen Supply-Dtl Ppng	31AUG05	07SEP05	5	C	
OFCGD2A43	Pull/IHR/Chk Pipe Isos Nitrogen Supply	08SEP05	05OCT05	20	C	
OFCGD2A45	Update Modl Nitrogen Supply	06OCT05	12OCT05	5	C	
OFCGD2A16	Release P&ID Tags for S3 Logic AFC Nitrgn Spply	06OCT05	19OCT05	10	C	
OFCGD2A49	ISS Pipe Isos For Fab Nitrogen Supp	13OCT05	09DEC05	40	C	
OFCGD2A59	P&ID/ISOs AFC Nitrogen Supply-Dtl Ppng	12DEC05	03JAN06	10	C	
OFCGD2A91	Supp Prep Spool Dwgs: Nitrogen Supply-Dtl Ppng	12DEC05	03JAN06	10	C	
OFCGD2A97	BV App/Rlf Spool Dwgs: Nitrogen Supply-Dtl Ppng	04JAN06	17JAN06	10	C	
FGD MAKEUP WATER						
Piping Design - Typical						
OFWSG2A01	Design/P&ID/J48_FGD Mkup Wtr	16MAY05	06JUN05	15	C	
OFWSG2A11	IHR S1 P&ID & Lists/Ctrl Dsgn Mtg_FGD Mkup Wtr	07JUN05	13JUN05	5	C	
OFWSG2A10	ISS P&ID & Lists For Own Rvw_FGD Mkup Wtr	18AUG05	31AUG05	10	C	
OFWSG2A18	Pull/Rev Lists/RFR Meeting_FGD Mkup Wtr	01SEP05	08SEP05	5	C	
OFWSG2A99	Prep/ISS Syst Descrpt_FGD Mkup Wtr	09SEP05	12SEP05	2	C	
OFWSG2A15	ISS P&ID For Routing(S2)_FGD Mkup Wtr	09SEP05	06OCT05	20	C	
OFWSG2A26	Pipe Route & Hang_FGD Mkup Wtr-Dtl Ppng	07OCT05	08FEB06	80	C	
OFWSG2A32	Electrnc Intrfrnce Chk_FGD Mkup Wtr-Dtl Ppng	09FEB06	15FEB06	5	C	
OFWSG2A43	Pull/IHR/Chk Pipe Isos FGD Mkup Wtr	16FEB06	15MAR06	20	C	
OFWSG2A65	Chk Pipe Hanger List_FGD Mkup Wtr-Dtl Ppng	14MAR06	15MAR06	2	C	
OFWSG2A45	Update Modl FGD Mkup Wtr	16MAR06	22MAR06	5	C	
OFWSG2A16	Release P&ID Tags for S3 Logics AFC_FGD Mkup Wtr	16MAR06	29MAR06	10	C	
OFWSG2A49	ISS Pipe Isos For Fab FGD Mkup Wtr	23MAR06	17MAY05	40	C	
OFWSG2A59	P&ID/ISOs AFC_FGD Mkup Wtr-Dtl Ppng	18MAY06	01JUN06	10	C	
OFWSG2A91	Supp Prep Spool Dwgs_FGD Mkup Wtr-Dtl Ppng	18MAY06	01JUN06	10	C	
OFWSG2A97	BV App/Rlf Spool Dwgs_FGD Mkup Wtr-Dtl Ppng	02JUN06	15JUN06	10	C	
FGD RECLAIM WATER						
Piping Design - Typical						
OFWSJ2A01	Design/P&ID/J48_FGD Rclm Wtr	16MAY05	06JUN05	15	C	
OFWSJ2A11	IHR S1 P&ID & Lists/CtrlDsgn Mtg_FGD Rclm Wtr	07JUN05	13JUN05	5	C	
OFWSJ2A10	ISS P&ID & Lists For Own Rvw_FGD Rclm Wtr	14JUN05	27JUN05	10	C	
OFWSJ2A18	Pull/Rev Lists/RFR Mtg_FGD Rclm Wtr	28JUN05	05JUL05	5	C	



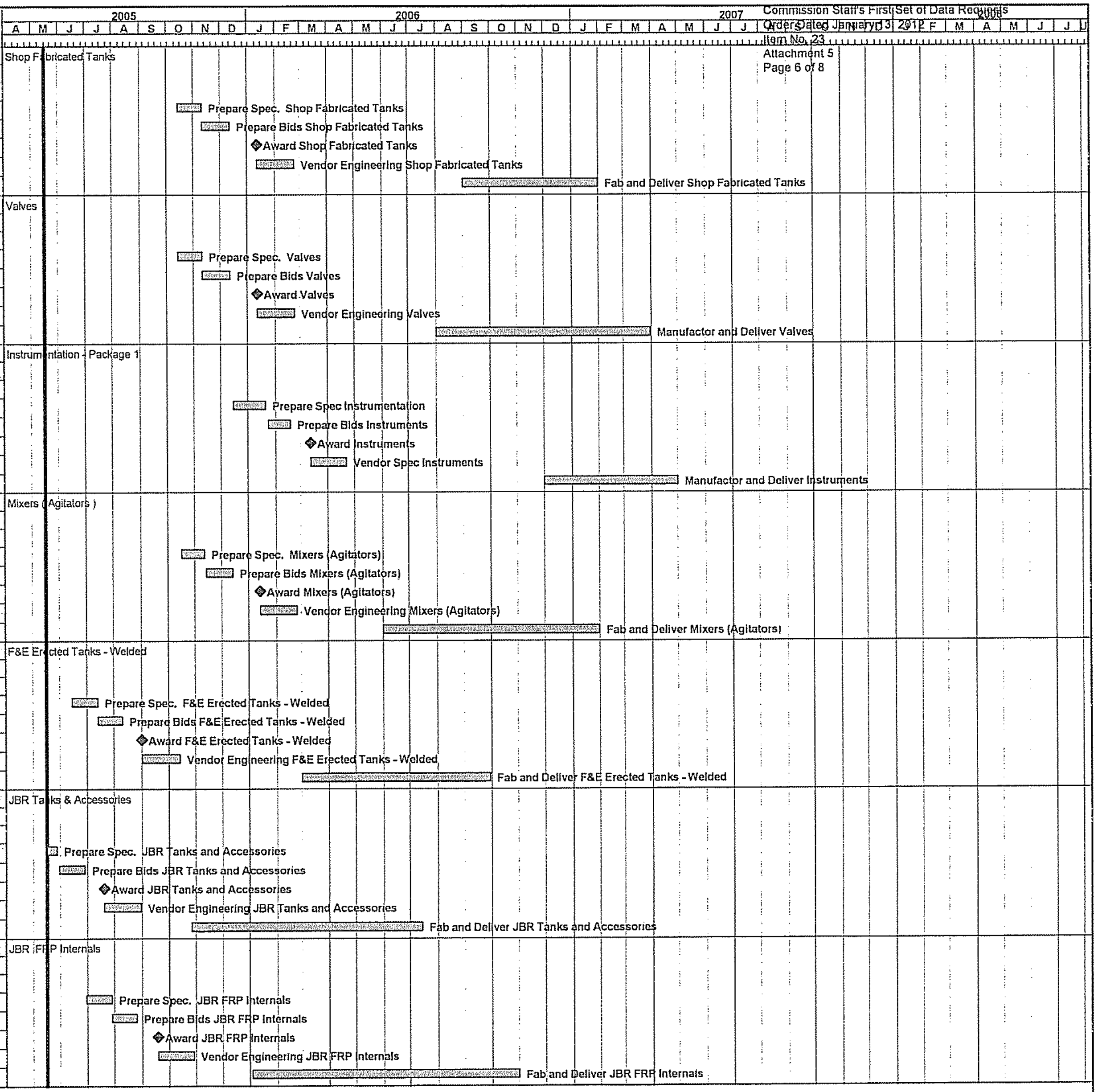
Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
OFWSJ2A99	Prep/ISS Syst Descrpt_FGD Rclm Wtr	06JUL05	07JUL05	2	C	
OFWSJ2A15	ISS P&ID For Routing(S2)_FGD Rclm Wtr	06JUL05	02AUG05	20	C	
OFWSJ2A26	Pipe Route & Hang_FGD Rclm Wtr-Dtl Ppng	03AUG05	23NOV05	80	C	
OFWSJ2A32	Electrnc Intrfrnce Chk_FGD Rclm Wtr-Dtl Ppng	28NOV05	02DEC05	5	C	
OFWSJ2A43	PullHR/Chk Pipe Isos FGD Rclm Wtr	05DEC05	10JAN06	20	C	
OFWSJ2A65	Chk Pipe Hanger List_FGD Rclm Wtr-Dtl Ppng	09JAN06	10JAN06	2	C	
OFWSJ2A45	Update Modl FGD Rclm Wtr	11JAN06	17JAN06	5	C	
OFWSJ2A16	Release P&ID Tags for S3 Logics AFC_FGD Rclm Wtr	11JAN06	24JAN06	10	C	
OFWSJ2A49	ISS Pipe Isos For Fab FGD Rclm Wtr	18JAN06	14MAR06	40	C	
OFWSJ2A59	P&ID/ISOs_FGD Rclm Wtr-Dtl Ppng	15MAR06	28MAR06	10	C	
OFWSJ2A91	Supp Prep Spool Dwgs_FGD Rclm Wtr-Dtl Ppng	15MAR06	28MAR06	10	C	
OFWSJ2A97	BV App/Rff Spool Dwgs_FGD Rclm Wtr-Dtl Ppng	29MAR06	11APR06	10	C	
PROCUREMENT						
Gas Cooler						
OF62051200	Prepare Spec. Gas Coolers	16JUN05	14JUL05	20		
OF62051210	Bid Period Gas Coolers	15JUL05	11AUG05	20		
OF62051220	Award Gas Coolers	12AUG05		0		
OF62051230	Vendor Engineering Gas Cooler	12AUG05	23SEP05	30		
OF62051240	Fab and Deliver Gas Coolers	27SEP05	31OCT06	274		
Oxidation Air Blowers						
OF62040900	Prepare Spec. Oxidation Air Blowers	16MAY05	13JUN05	20		
OF62040905	Bid Period Oxidation Air Blowers	14JUN05	12JUL05	20		
OF62040910	Award Oxidation Air Blowers	03AUG05		0		
OF62040915	Vendor Engineering Oxidation Air Blowers	03AUG05	14SEP05	30		
OF62040920	Fab and Deliver Oxidation Air Blowers	03APR06	30MAR07	249		
FGD Limestone Slurry Preparation (Ball Mills)						
OF62180900	Prepare Spec. Oxidation Air Blowers	16MAY05	27MAY05	10		
OF62180905	Prepare Bids Limestone Slry Prep. (Ball Mills)	31MAY05	27JUN05	20		
OF62180910	Award Limestone Slry Prep. (Ball Mills)	20JUL05		0		
OF62180915	Vendor Engineering Limestone Slry Prep. (Ball Mi	20JUL05	30AUG05	30		
OF62180920	Fab and Deliver Limestone Slry Prep. (Ball Mills	03JAN06	30MAR07	313		
FGD Byproduct Dewatering						
OF628X900	Prepare Spec. Byproduct Dewatering	16MAY05	13JUN05	20		
OF628X905	Prepare Bids Byproduct Dewatering	14JUN05	12JUL05	20		
OF628X910	Award Byproduct Dewatering	03AUG05		0		
OF628X915	Vendor Engineering Byproduct Dewatering	03AUG05	14SEP05	30		
OF628X920	Fab and Deliver Byproduct Dewatering	01FEB06	22DEC06	228		
Hydrocyclones						
OF6218900	Prepare Spec. Hydrocyclones	17OCT05	11NOV05	20		
OF6218905	Prepare Bids Hydrocyclones	14NOV05	13DEC05	20		
OF6218910	Award Hydrocyclones	13JAN06		0		
OF6218915	Vendor Engineering Hydrocyclones	13JAN06	23FEB06	30		
OF6218920	Fab and Deliver Hydrocyclones	07JUL06	28FEB07	160		



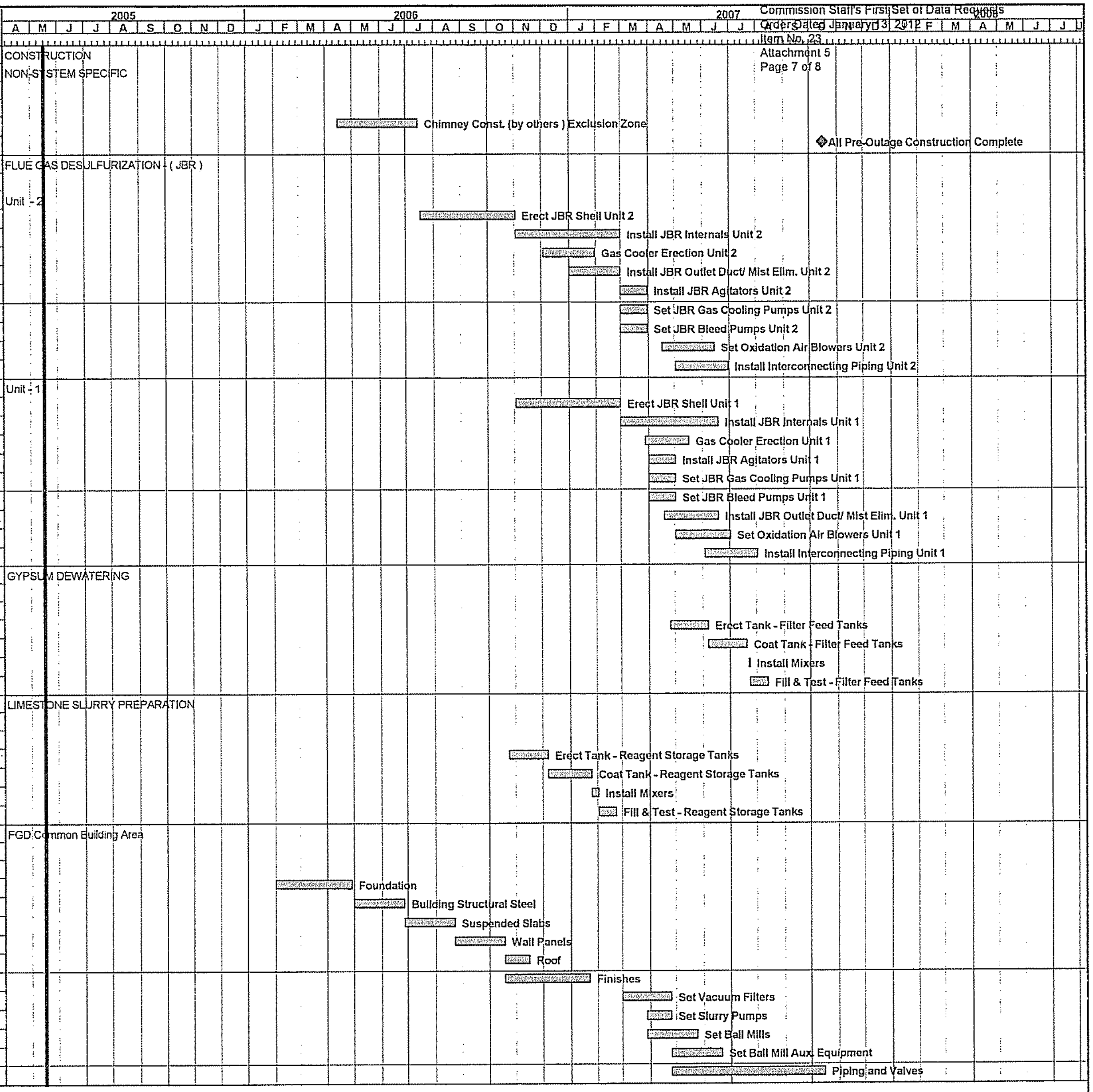
Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
Fabricated Steel Pipe						
OF622A900	Prepare Spec. Fabricated Steel Pipe	07APR06	04MAY06	20		
OF622A905	Prepare Bids Fabricated Steel Pipe	05MAY06	02JUN06	20		
OF622A910	Award Fabricated Steel Pipe	26JUN06		0		
OF622A915	Vendor Engineering Fabricated Steel Pipe	26JUN06	07AUG06	30		
OF622A920	Fab and Deliver Fabricated Steel Pipe	08AUG06	30MAR07	160		
FRP Pipe						
62220900	Prepare Spec. FRP Pipe	16MAY05	13JUN05	20		
62220905	Prepare Bids FRP Pipe	14JUN05	12JUL05	20		
62220910	Award FRP Pipe	03AUG05		0		
62220915	Vendor Engineering FRP Pipe	03AUG05	14SEP05	30		
62220920	Fab and Deliver FRP Pipe	24MAY06	14MAR07	200		
JBR Sparger Tubes						
OF62221900	Prepare Spec. JBR Sparger Tubes	27JAN06	23FEB06	20		
OF62221905	Prepare Bids JBR Sparger Tubes	24FEB06	23MAR06	20		
OF62221910	Award JBR Sparger Tubes	14APR06		0		
OF62221915	Vendor Engineering JBR Sparger Tubes	14APR06	07AUG06	80		
OF62221920	Fab and Deliver JBR Sparger Tubes	20SEP06	31JAN07	88		
Mist Eliminators						
OF62241900	Prepare Spec. Mist Eliminators	16MAY05	13JUN05	20		
OF62241905	Prepare Bids Mist Eliminators	14JUN05	12JUL05	20		
OF62241910	Award Mist Eliminators	03AUG05		0		
OF62241915	Vendor Engineering Mist Eliminators	03AUG05	14SEP05	30		
OF62241920	Fab and Deliver Mist Eliminators	31MAR06	31JAN07	208		
Slurry Pumps						
OF62262900	Prepare Spec. Slurry Pumps	15SEP05	12OCT05	20		
OF62262905	Prepare Bids Slurry Pumps	13OCT05	09NOV05	20		
OF62262910	Award Slurry Pumps	05DEC05		0		
OF62262915	Vendor Engineering Slurry Pumps	05DEC05	24JAN06	30		
OF62262920	Fab and Deliver Slurry Pumps	01MAY06	28FEB07	207		
General Service Horizontal Pumps						
OF62261900	Prepare Spec. Gen Svc Horizontal Pumps	14NOV05	13DEC05	20		
OF62261905	Prepare Bids Gen Svc Horizontal Pumps	14DEC05	19JAN06	20		
OF62261910	Award Gen Svc Horizontal Pumps	10FEB06		0		
OF62261915	Vendor Engineering Gen Svc Horizontal Pumps	10FEB06	23MAR06	30		
OF62261920	Fab and Deliver Gen Svc Horizontal Pumps	01SEP06	28FEB07	120		
General Service Vertical Pumps						
OF6226A900	Prepare Spec. Gen Svc Vertical Pumps	14NOV05	13DEC05	20		
OF6226A905	Prepare Bids Gen Svc Vertical Pumps	14DEC05	19JAN06	20		
OF6226A910	Award Gen Svc Vertical Pumps	10FEB06		0		
OF6226A915	Vendor Engineering Gen Svc Vertical Pumps	10FEB06	23MAR06	30		
OF6226A920	Fab and Deliver Gen Svc Vertical Pumps	01SEP06	28FEB07	120		



Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
Shop Fabricated Tanks						
OF62360900	Prepare Spec. Shop Fabricated Tanks	14OCT05	10NOV05	20		
OF62360905	Prepare Bids Shop Fabricated Tanks	11NOV05	12DEC05	20		
OF62360910	Award Shop Fabricated Tanks	12JAN06		0		
OF62360915	Vendor Engineering Shop Fabricated Tanks	12JAN06	22FEB06	30		
OF62360920	Fab and Deliver Shop Fabricated Tanks	01SEP06	31JAN07	100		
Valves						
OF6238B900	Prepare Spec. Valves	14OCT05	10NOV05	20		
OF6238B905	Prepare Bids Valves	11NOV05	12DEC05	20		
OF6238B910	Award Valves	12JAN06		0		
OF6238B915	Vendor Engineering Valves	12JAN06	22FEB06	30		
OF6238B920	Manufactor and Deliver Valves	01AUG06	30MAR07	165		
Instrumentation - Package 1						
640500900	Prepare Spec Instrumentation	15DEC05	20JAN06	20		
640500905	Prepare Bids Instruments	23JAN06	17FEB06	20		
640500910	Award Instruments	13MAR06		0		
640500915	Vendor Spec Instruments	13MAR06	21APR06	30		
640500920	Manufactor and Deliver Instruments	01DEC06	30APR07	101		
Mixers (Agitators)						
OF65070900	Prepare Spec. Mixers (Agitators)	17OCT05	11NOV05	20		
OF65070905	Prepare Bids Mixers (Agitators)	14NOV05	13DEC05	20		
OF65070910	Award Mixers (Agitators)	13JAN06		0		
OF65070915	Vendor Engineering Mixers (Agitators)	13JAN06	23FEB06	30		
OF65070920	Fab and Deliver Mixers (Agitators)	01JUN06	31JAN07	165		
F&E Erected Tanks - Welded						
OF72360A00	Prepare Spec. F&E Erected Tanks - Welded	15JUN05	13JUL05	20		
OF72360A05	Prepare Bids F&E Erected Tanks - Welded	14JUL05	10AUG05	20		
OF72360A10	Award F&E Erected Tanks - Welded	01SEP05		0		
OF72360A15	Vendor Engineering F&E Erected Tanks - Welded	01SEP05	13OCT05	30		
OF72360A20	Fab and Deliver F&E Erected Tanks - Welded	01MAR06	29SEP06	150		
JBR Tanks & Accessories						
OF72360900	Prepare Spec. JBR Tanks and Accessories	16MAY05	27MAY05	10		
OF72360905	Prepare Bids JBR Tanks and Accessories	31MAY05	27JUN05	20		
OF72360910	Award JBR Tanks and Accessories	20JUL05		0		
OF72360915	Vendor Engineering JBR Tanks and Accessories	20JUL05	30AUG05	30		
OF72360920	Fab and Deliver JBR Tanks and Accessories	27OCT05	14JUL06	176		
JBR FRP Internals						
OF7260950	Prepare Spec. JBR FRP Internals	30JUN05	28JUL05	20		
OF7260955	Prepare Bids JBR FRP Internals	29JUL05	25AUG05	20		
OF7260960	Award JBR FRP Internals	19SEP05		0		
OF7260965	Vendor Engineering JBR FRP Internals	19SEP05	28OCT05	30		
OF7260970	Fab and Deliver JBR FRP Internals	03JAN06	31OCT06	213		



Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
CONSTRUCTION						
NON-SYSTEM SPECIFIC						
OFCCC1-100	Chimney Const. (by others) Exclusion Zone	14APR06	14JUL06	64		
OFMS000-0Z	All Pre-Outage Construction Complete		15OCT07	0		
FLUE GAS DESULFURIZATION - (JBR)						
Unit - 2						
OFCCC2-200	Erect JBR Shell Unit 2	17JUL06	01NOV06	77		
OFCCC2-205	Install JBR Internals Unit 2	02NOV06	28FEB07	77		
OFCCC2-210	Gas Cooler Erection Unit 2	04DEC06	29JAN07	35		
OFCCC2-215	Install JBR Outlet Duct/ Mist Elim. Unit 2	02JAN07	28FEB07	42		
OFCCC2-220	Install JBR Agitators Unit 2	01MAR07	30MAR07	22		
OFCCC2-225	Set JBR Gas Cooling Pumps Unit 2	01MAR07	30MAR07	22		
OFCCC2-230	Set JBR Bleed Pumps Unit 2	01MAR07	30MAR07	22		
OFCCC2-235	Set Oxidation Air Blowers Unit 2	16APR07	14JUN07	43		
OFCCC2-240	Install Interconnecting Piping Unit 2	02MAY07	29JUN07	42		
Unit - 1						
OFCCC1-200	Erect JBR Shell Unit 1	02NOV06	28FEB07	77		
OFCCC1-205	Install JBR Internals Unit 1	01MAR07	18JUN07	77		
OFCCC1-210	Gas Cooler Erection Unit 1	29MAR07	16MAY07	35		
OFCCC1-220	Install JBR Agitators Unit 1	02APR07	01MAY07	22		
OFCCC1-225	Set JBR Gas Cooling Pumps Unit 1	02APR07	01MAY07	22		
OFCCC1-230	Set JBR Bleed Pumps Unit 1	02APR07	01MAY07	22		
OFCCC1-215	Install JBR Outlet Duct/ Mist Elim. Unit 1	19APR07	18JUN07	42		
OFCCC1-235	Set Oxidation Air Blowers Unit 1	02MAY07	02JUL07	43		
OFCCC1-240	Install Interconnecting Piping Unit 1	04JUN07	01AUG07	42		
GYPSUM DEWATERING						
OFFWC-113	Erect Tank - Filter Feed Tanks	26APR07	07JUN07	30	C	
OFFWC-114	Coat Tank - Filter Feed Tanks	08JUN07	20JUL07	30	C	
OFFWC-115	Install Mixers	23JUL07	23JUL07	1		
OFFWC-117	Fill & Test - Filter Feed Tanks	24JUL07	13AUG07	15	C	
LIMESTONE SLURRY PREPARATION						
OFBMC-113	Erect Tank - Reagent Storage Tanks	24OCT06	06DEC06	30	C	
OFBMC-114	Coat Tank - Reagent Storage Tanks	07DEC06	25JAN07	30	C	
OFBMC-115	Install Mixers	26JAN07	01FEB07	5	C	
OFBMC-117	Fill & Test - Reagent Storage Tanks	02FEB07	22FEB07	15	C	
FGD Common Building Area						
OFBSM-01	Foundation	01FEB06	28APR06	63		
OFBSM-11	Building Structural Steel	01MAY06	26JUN06	40		
OFBSM-21	Suspended Slabs	27JUN06	22AUG06	40		
OFBSM-31	Wall Panels	23AUG06	18OCT06	40		
OFBSM-41	Roof	19OCT06	15NOV06	20		
OFBSM-51	Finishes	19OCT06	22JAN07	60		
OFBSM-60	Set Vacuum Filters	01MAR07	25APR07	40		
OFBSM-85	Set Slurry Pumps	29MAR07	25APR07	20		
OFBSM-65	Set Ball Mills	29MAR07	23MAY07	40		
OFBSM-70	Set Ball Mill Aux. Equipment	26APR07	21JUN07	40		
OFBSM-90	Piping and Valves	26APR07	15OCT07	120		



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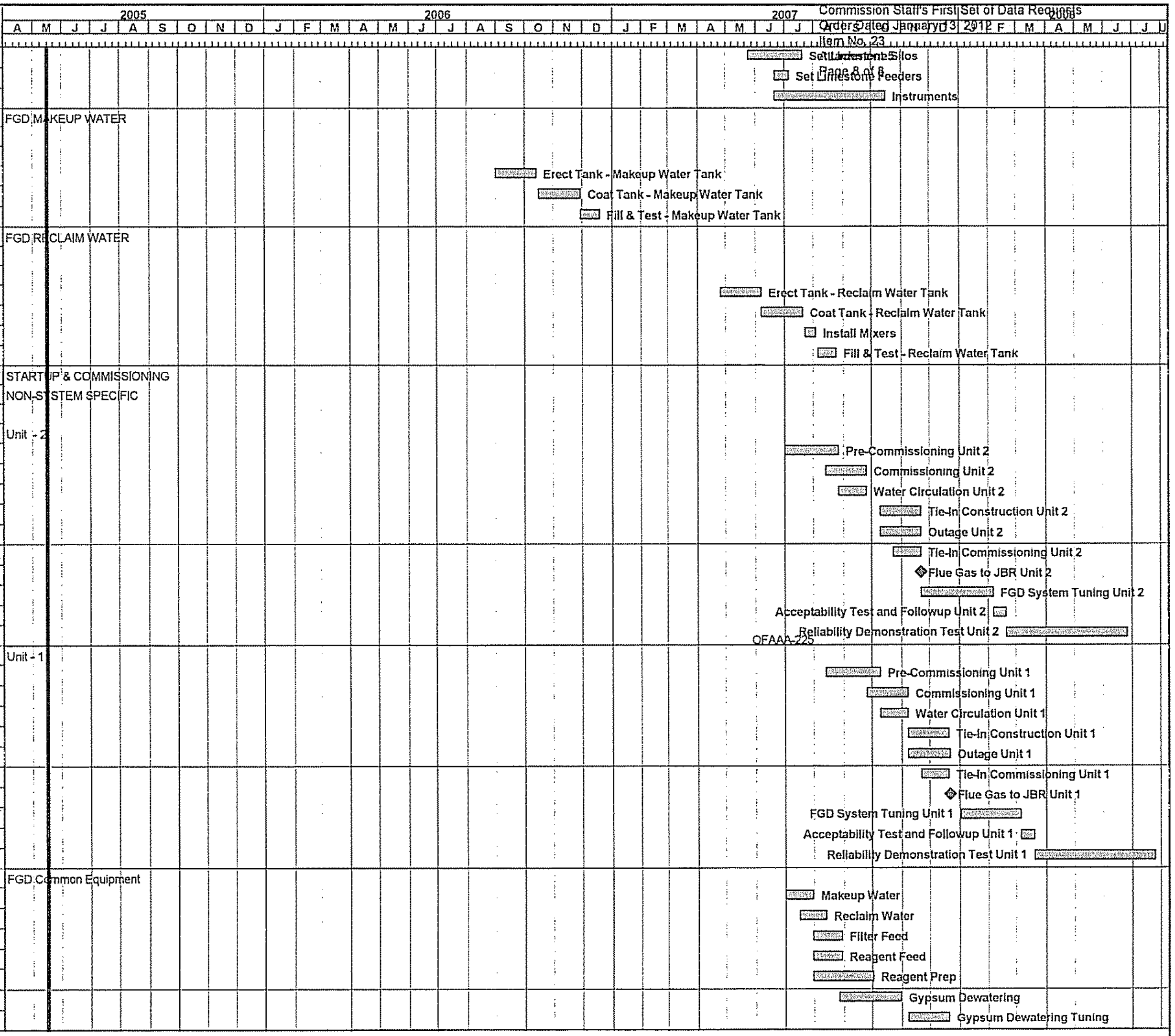
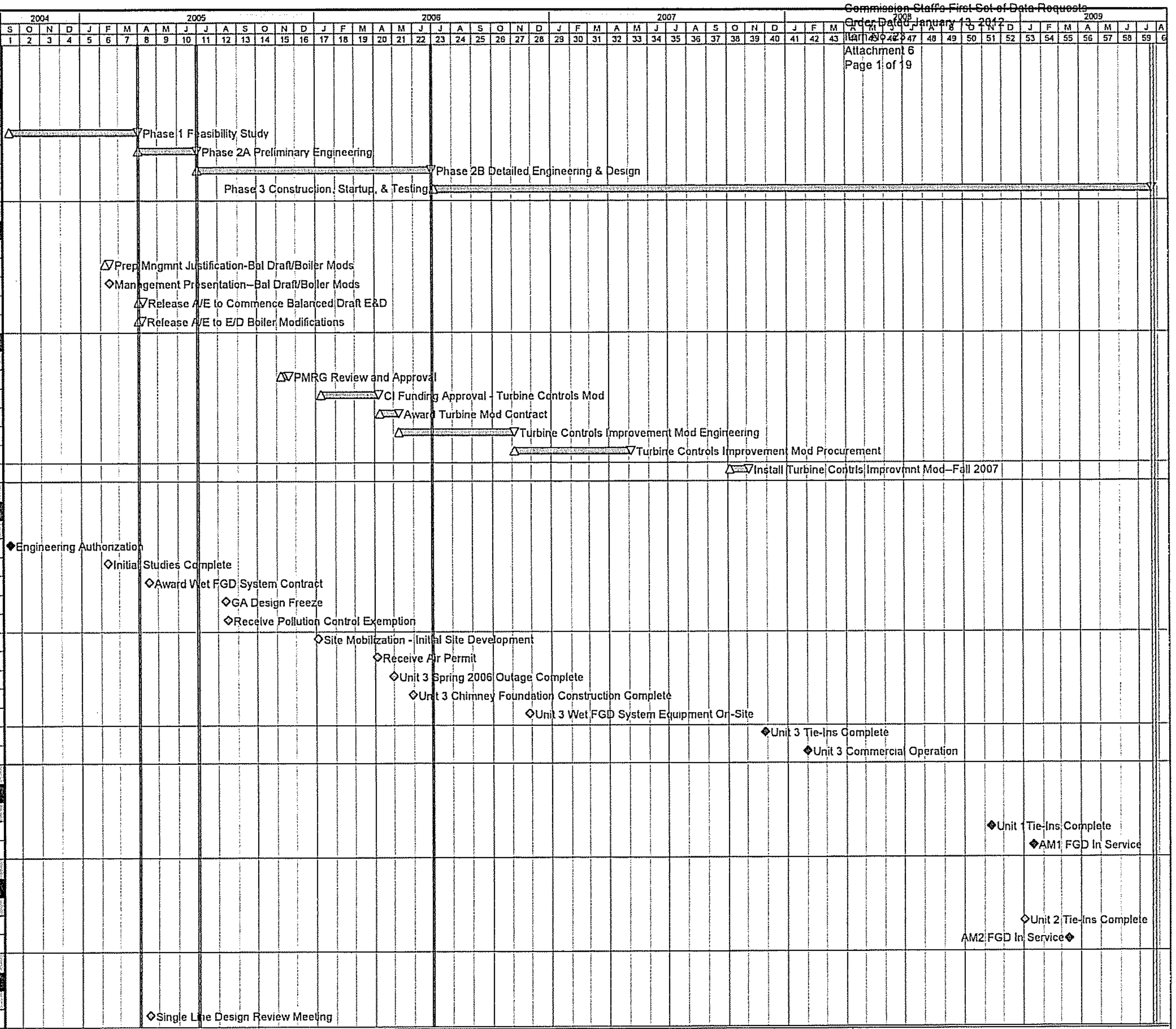
Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	DISC	TEMP
OFBSM-75	Set Limestone Silos	24MAY07	20JUL07	40		
OFBSM-80	Set Limestone Feeders	22JUN07	05JUL07	10		
OFBSM-95	Instruments	22JUN07	15OCT07	80		
FGD MAKEUP WATER						
OFWSG-113	Erect Tank - Makeup Water Tank	01SEP06	13OCT06	30		
OFWSG-114	Coat Tank - Makeup Water Tank	16OCT06	28NOV06	30		
OFWSG-117	Fill & Test - Makeup Water Tank	29NOV06	19DEC06	15		
FGD RECLAIM WATER						
OFWSJ-113	Erect Tank - Reclaim Water Tank	26APR07	07JUN07	30		
OFWSJ-114	Coat Tank - Reclaim Water Tank	08JUN07	20JUL07	30		
OFWSJ-124	Install Mixers	23JUL07	03AUG07	10		
OFWSJ-117	Fill & Test - Reclaim Water Tank	06AUG07	24AUG07	15		
STARTUP & COMMISSIONING						
NON-SYSTEM SPECIFIC						
Unit - 2						
OFAAA-200	Pre-Commissioning Unit 2	02JUL07	27AUG07	40		
OFAAA-205	Commissioning Unit 2	14AUG07	25SEP07	30		
OFAAA-210	Water Circulation Unit 2	28AUG07	25SEP07	20		
OFAAA-220	Tie-In Construction Unit 2	10OCT07	20NOV07	30		
OFAAA-215	Outage Unit 2	10OCT07	21NOV07	31		
OFAAA-225	Tie-In Commissioning Unit 2	24OCT07	20NOV07	20		
OFAAA-231	Flue Gas to JBR Unit 2	22NOV07		0		
OFAAA-235	FGD System Tuning Unit 2	22NOV07	05FEB08	45		
OFAAA-240	Acceptability Test and Followup Unit 2	06FEB08	19FEB08	10		
OFAAA-245	Reliability Demonstration Test Unit 2	20FEB08	25JUN08	90		
Unit - 1						
OFAAA-300	Pre-Commissioning Unit 1	14AUG07	09OCT07	40		
OFAAA-305	Commissioning Unit 1	26SEP07	06NOV07	30		
OFAAA-310	Water Circulation Unit 1	10OCT07	06NOV07	20		
OFAAA-320	Tie-In Construction Unit 1	07NOV07	20DEC07	30		
OFAAA-315	Outage Unit 1	07NOV07	21DEC07	31		
OFAAA-325	Tie-In Commissioning Unit 1	21NOV07	20DEC07	20		
OFAAA-330	Flue Gas to JBR Unit 1	22DEC07		0		
OFAAA-335	FGD System Tuning Unit 1	02JAN08	04MAR08	45		
OFAAA-340	Acceptability Test and Followup Unit 1	05MAR08	18MAR08	10		
OFAAA-345	Reliability Demonstration Test Unit 1	19MAR08	24JUL08	90		
FGD Common Equipment						
OFAAA-355	Makeup Water	02JUL07	30JUL07	20		
OFAAA-365	Reclaim Water	17JUL07	13AUG07	20		
OFAAA-375	Filter Feed	31JUL07	29AUG07	22		
OFAAA-385	Reagent Feed	31JUL07	29AUG07	22		
OFAAA-395	Reagent Prep	31JUL07	01OCT07	44		
OFAAA-405	Gypsum Dewatering	28AUG07	30OCT07	45		
OFAAA-415	Gypsum Dewatering Tuning	07NOV07	20DEC07	30		



Act. ID	Activity Description	Orig Dur	Start	Finish
00 MILESTONES / STUDIES / PERMITTING				
PH PROJECT PHASES				
C Common				
MS0002	Phase 1 Feasibility Study	140	13SEP04*	31MAR05
MS0004	Phase 2A Preliminary Engineering	63	01APR05	30JUN05
MS0006	Phase 2B Detailed Engineering & Design	253	01JUL05	30JUN06
MS0008	Phase 3 Construction, Startup, & Testing	783	03JUL06	23JUL09
GNL GENERAL ENGINEERING				
B280 Boiler Modifications				
C Common				
SLB180.02	Prep Mngmnt Justification-Bal Draft/Boiler Mods	5	08FEB05*	14FEB05
MS03XXX	Management Presentation--Bal Draft/Boiler Mods	0	15FEB05	
SLB170.04	Release A/E to Commence Balanced Draft E&D	5	01APR05*	07APR05
SLB180.05	Release A/E to E/D Boiler Modifications	5	01APR05*	05APR05
B290 Turbine Controls Modification - Unit 3				
C Common				
AEPM1010	PMRG Review and Approval	12	07NOV05*	18NOV05
AEPM1012	CI Funding Approval - Turbine Controls Mod	90	09JAN06*	08APR06
AEPM1016	Award Turbine Mod Contract	30	10APR06*	09MAY06
AEPM1014	Turbine Controls Improvement Mod Engineering	180	09MAY06	04NOV06
PRPM1018	Turbine Controls Improvement Mod Procurement	180	05NOV06	03MAY07
CNPM1020	Install Turbine Contrls Improvmnt Mod--Fall 2007	30	05OCT07*	03NOV07
M3 MILESTONES - UNIT 3				
MS01 Project Milestones				
C Common				
MS0010	Engineering Authorization	0	13SEP04*	
MS0030	Initial Studies Complete	0		11FEB05
MS0020	Award Wet FGD System Contract	0		15APR05
MS0050	GA Design Freeze	0		12AUG05
MS1450	Receive Pollution Control Exemption	0		16AUG05
MS0060	Site Mobilization - Initial Site Development	0		02JAN06
MS1470	Receive Air Permit	0		04APR06
MS0080	Unit 3 Spring 2006 Outage Complete	0		30APR06
MS0070	Unit 3 Chimney Foundation Construction Complete	0		30MAY06
MS0090	Unit 3 Wet FGD System Equipment On-Site	0		27NOV06
MS0100	Unit 3 Tie-Ins Complete	0		26NOV07
MS0110	Unit 3 Commercial Operation	0		31JAN08*
M1 MILESTONES - UNIT 1				
MS01 Project Milestones				
1 Unit 1				
M10100	Unit 1Tie-Ins Complete	0		10NOV08
M11600	AM1 FGD In Service	0		16JAN09
M2 MILESTONES - UNIT 2				
MS01 Project Milestones				
2 Unit 2				
M11100	Unit 2 Tie-Ins Complete	0		02JAN09
M11610	AM2 FGD In Service	0		11MAR09
MS DESIGN REVIEW MEETINGS				
MS02 Design Review Meetings				
C Common				
MS0220	Single Line Design Review Meeting	0		15APR05



Project: SUMH
Layout: LT-E1
Run Date: 30DEC04 09:29

Schedule Summary
Progress Bar
Critical Activity

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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	N/A	
01NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

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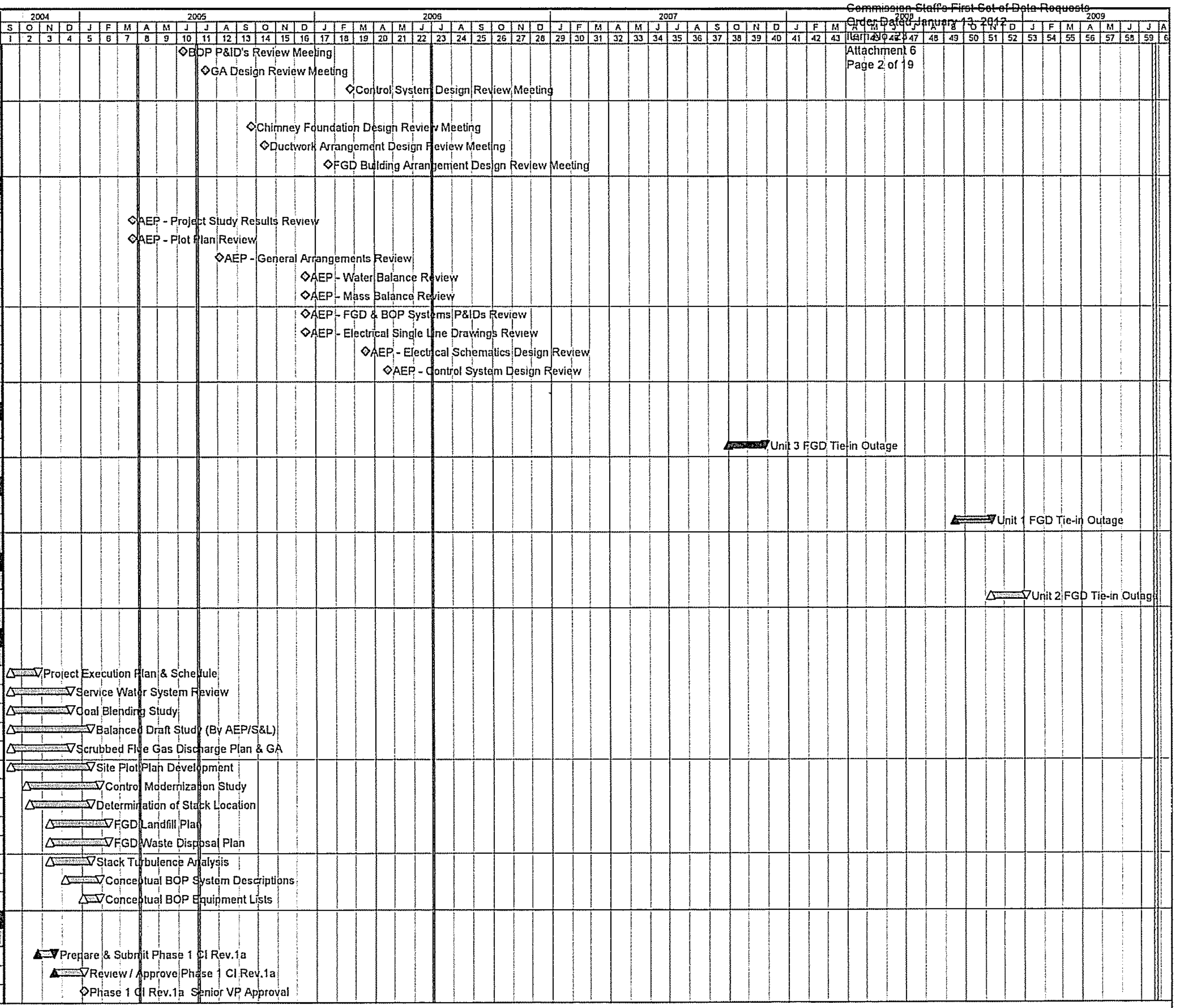
Act. ID	Activity Description	Orig Dur	Start	Finish
MS0230	BOP P&ID's Review Meeting	0		10JUN05
MS0210	GA Design Review Meeting	0		15JUL05
MS0270	Control System Design Review Meeting	0		24FEB06
3 Unit 3				
MS0240	Chimney Foundation Design Review Meeting	0		23SEP05
MS0250	Ductwork Arrangement Design Review Meeting	0		14OCT05
MS0260	FGD Building Arrangement Design Review Meeting	0		20JAN06
MS03 AEP Design Review				
C Common				
MS0400	AEP - Project Study Results Review	0		22MAR05
MS0430	AEP - Plot Plan Review	0		22MAR05
MS0440	AEP - General Arrangements Review	0		04AUG05
MS0410	AEP - Water Balance Review	0		14DEC05
MS0420	AEP - Mass Balance Review	0		14DEC05
MS0450	AEP - FGD & BOP Systems P&IDs Review	0		14DEC05
MS0470	AEP - Electrical Single Line Drawings Review	0		14DEC05
MS0480	AEP - Electrical Schematics Design Review	0		17MAR06*
MS0490	AEP - Control System Design Review	0		21APR06
S3 PRE-COMMISSIONING / START-UP UNIT 3				
SU98 System Start-up, Testing & Checkout				
3 Unit 3				
CN90200	Unit 3 FGD Tie-in Outage	56	02OCT07	26NOV07
S1 PRE-COMMISSIONING / START-UP UNIT 1				
SU98 System Start-up, Testing & Checkout				
1 Unit 1				
C190200	Unit 1 FGD Tie-in Outage	56	16SEP08*	10NOV08
S2 PRE-COMMISSIONING / START-UP UNIT 2				
SU98 System Start-up, Testing & Checkout				
2 Unit 2				
C290200	Unit 2 FGD Tie-in Outage	56	10NOV08*	04JAN09
PS PROJECT FUNDING				
B100 General Studies / Preliminary Engineering				
C Common				
ENB100.00	Project Execution Plan & Schedule	31	13SEP04	25OCT04
ENB110.00	Service Water System Review	68	13SEP04	15DEC04
ENB140.00	Coal Blending Study	68	13SEP04	15DEC04
ENB170.00	Balanced Draft Study (By AEP/S&L)	90	13SEP04	14JAN05
ENB190.00	Scrubbed Flue Gas Discharge Plan & GA	68	13SEP04	15DEC04
ENB230.00	Site Plot Plan Development	90	13SEP04	14JAN05
ENB160.00	Control Modernization Study	81	08OCT04	28JAN05
ENB210.00	Determination of Stack Location	69	12OCT04	14JAN05
ENB200.00	FGD Landfill Plan	66	12NOV04	11FEB05
ENB205.00	FGD Waste Disposal Plan	66	12NOV04	11FEB05
ENB220.00	Stack Turbulence Analysis	46	12NOV04	14JAN05
ENB260.00	Conceptual BOP System Descriptions	40	06DEC04	28JAN05
ENB270.00	Conceptual BOP Equipment Lists	20	03JAN05	28JAN05
B314 Phase 1 CI Rev.1a				
C Common				
AM123_5076	Prepare & Submit Phase 1 CI Rev.1a	20	25OCT04A	19NOV04A
AM123_5077	Review / Approve Phase 1 CI Rev.1a	28	19NOV04A	03JAN05
AM123_5078	Phase 1 CI Rev.1a Senior VP Approval	0		03JAN05



Project: SUMH
Layout: LT-E1
Run Date: 30DEC04 09:29

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▭ Schedule Summary
▬ Progress Bar
▬ Critical Activity

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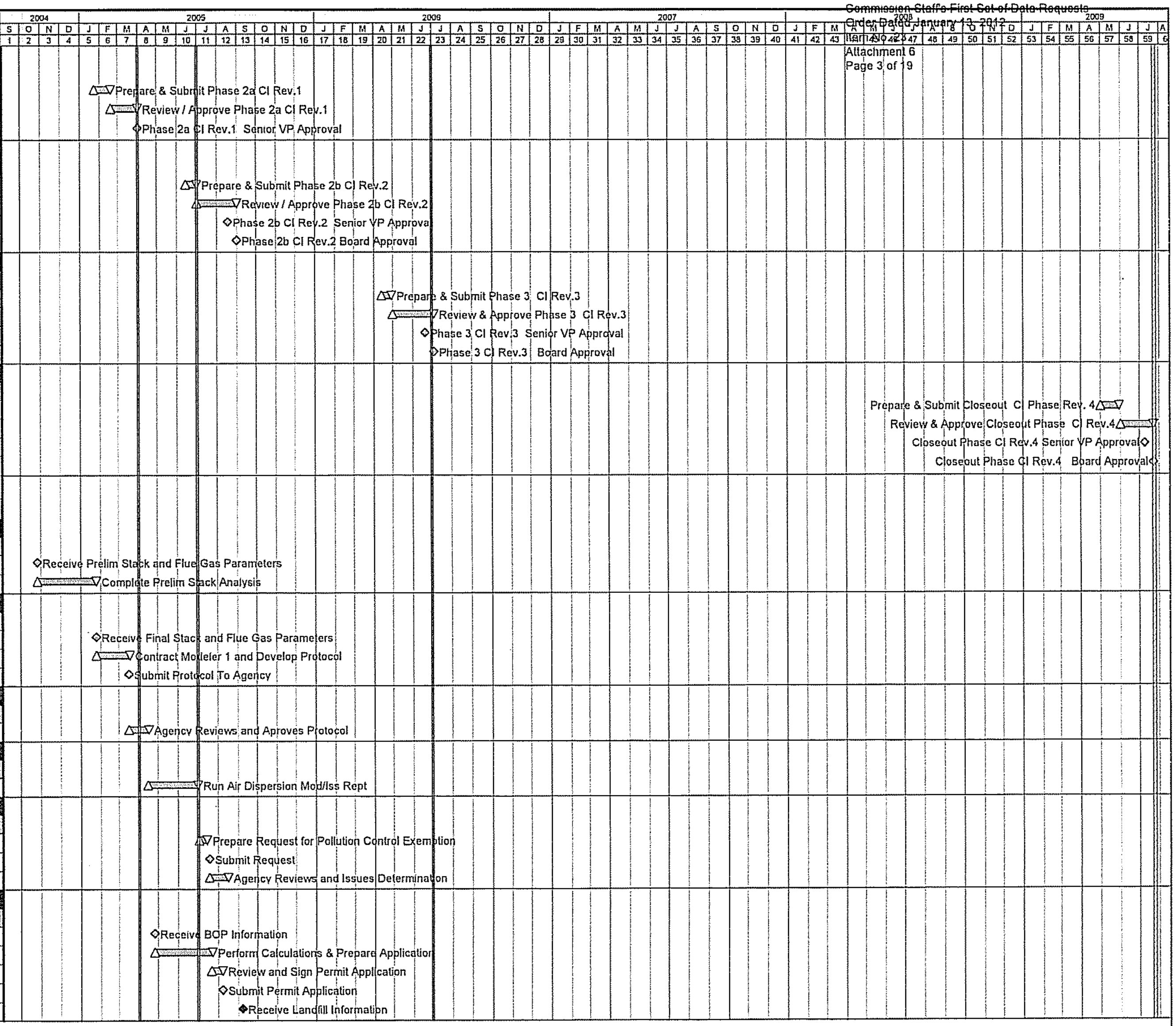
American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	N/A	
21NOV04	Preliminary Issue	DJS	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

Act. ID	Activity Description	Orig Dur	Start	Finish
B316 Phase 2a CI Rev.1				
C Common				
AM123_5080	Prepare & Submit Phase 2a CI Rev.1	20	24JAN05*	18FEB05
AM123_5095	Review / Approve Phase 2a CI Rev.1	30	18FEB05	31MAR05
AM123_5090	Phase 2a CI Rev.1 Senior VP Approval	0		31MAR05
B318 Phase 2b CI Rev.2				
C Common				
AM123_5160	Prepare & Submit Phase 2b CI Rev.2	12	15JUN05*	30JUN05
AM123_5165	Review / Approve Phase 2b CI Rev.2	43	01JUL05	31AUG05
AM123_5166	Phase 2b CI Rev.2 Senior VP Approval	0		17AUG05
AM123_9275	Phase 2b CI Rev.2 Board Approval	0		31AUG05
B322 Phase 3 CI Rev.3				
C Common				
AM123_5130	Prepare & Submit Phase 3 CI Rev.3	11	14APR06*	28APR06
AM123_5135	Review & Approve Phase 3 CI Rev.3	45	01MAY06	03JUL06
AM123_5136	Phase 3 CI Rev.3 Senior VP Approval	0		19JUN06
AM123_9260	Phase 3 CI Rev.3 Board Approval	0		03JUL06
B324 CI Phase Rev. 4				
C Common				
AM123_5180	Prepare & Submit Closeout CI Phase Rev. 4	21	01MAY09*	29MAY09
AM123_5185	Review & Approve Closeout Phase CI Rev.4	39	01JUN09	23JUL09
AM123_5137	Closeout Phase CI Rev.4 Senior VP Approval	0		09JUL09
AM123_5290	Closeout Phase CI Rev.4 Board Approval	0		23JUL09
08 ENVIRONMENTAL (PERMITS)				
AIR AIR ISSUES				
AEP02 Stack Option Modeling				
C Common				
AIRP3550	Receive Prelim Stack and Flue Gas Parameters	0	27OCT04	
AIRP3560	Complete Prelim Stack Analysis	65	27OCT04	25JAN05
AEP03 Air Modeling Protocal Submittal				
C Common				
AIRP3570	Receive Final Stack and Flue Gas Parameters	0	26JAN05	
AIRP3580	Contract Modeler 1 and Develop Protocol	37	26JAN05	17MAR05
AIRP3590	Submit Protocol To Agency	0	17MAR05	
AEP04 Agency Reviews and Approves Protocal				
C Common				
AIRP3600	Agency Reviews and Aproves Protocol	22	17MAR05	15APR05
AEP05 Conduct Air Modeling				
C Common				
AIRP3610	Run Air Dispersion Mod/Iss Rept	56	15APR05	01JUL05
AEP06 Pollution Control Exemption				
C Common				
AIRP3612	Prepare Request for Pollution Control Exemption	10	04JUL05	15JUL05
AIRP3614	Submit Request	0	18JUL05	
AIRP3616	Agency Reviews and Issues Determination	22	18JUL05	16AUG05
AEP07 Submit Air Permit Application				
C Common				
AIRP3620	Receive BOP Information	0	25APR05	
AIRP3630	Perform Calculations & Prepare Application	65	25APR05	22JUL05
AIRP3640	Review and Sign Permit Application	12	22JUL05	08AUG05
AIRP3650	Submit Permit Application	0	09AUG05	
AIRP3800	Receive Landfill Information	0	09SEP05*	



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Schedule Summary
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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
27OCT04	Initial Draft	N/A	
01NOV04	Preliminary Issue	DJS	
30NOV04	Preliminary Project Schedule	MSS	
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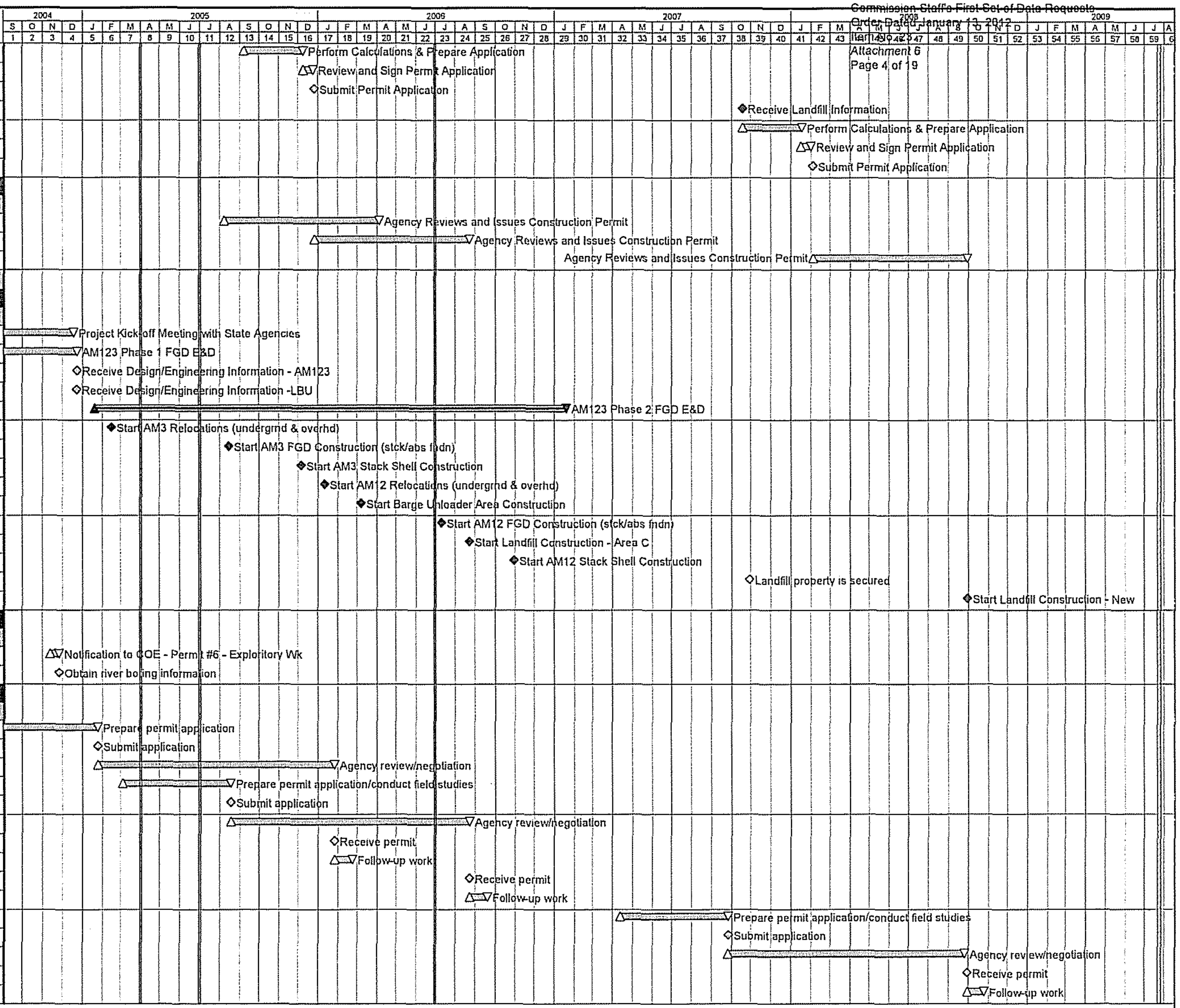
Act. ID	Activity Description	Orig Dur	Start	Finish
AIRP3810	Perform Calculations & Prepare Application	65	09SEP05	08DEC05
AIRP3820	Review and Sign Permit Application	12	08DEC05	23DEC05
AIRP3830	Submit Permit Application	0	26DEC05	
AIRP3700	Receive Landfill Information	0	19OCT07*	
AIRP3710	Perform Calculations & Prepare Application	65	19OCT07	17JAN08
AIRP3720	Review and Sign Permit Application	12	17JAN08	01FEB08
AIRP3730	Submit Permit Application	0	04FEB08	
AEP08 Receive Construction Permit				
C Common				
AIRP3660	Agency Reviews and Issues Construction Permit	171	09AUG05	04APR06
AIRP3840	Agency Reviews and Issues Construction Permit	171	26DEC05	21AUG06
AIRP3740	Agency Reviews and Issues Construction Permit	171	04FEB08	29SEP08
H20 WATER ISSUES				
AEP01 Preliminary Activities				
C Common				
ENRM3959	Project Kick-off Meeting with State Agencies	120	05JUL04A	17DEC04
ENRM3962	AM123 Phase 1 FGD E&D	89	23AUG04A	23DEC04
ENRM4010	Receive Design/Engineering Information - AM123	0	24DEC04	
ENRM4119	Receive Design/Engineering Information -LBU	0	24DEC04	
ENRM3966	AM123 Phase 2 FGD E&D	520	21JAN05*	18JAN07
ENRM3970	Start AM3 Relocations (undergrnd & overhd)	0	15FEB05*	
ENRM3972	Start AM3 FGD Construction (stck/abs fndn)	0	16AUG05*	
ENRM3974	Start AM3 Stack Shell Construction	0	06DEC05*	
ENRM3976	Start AM12 Relocations (undergrnd & overhd)	0	10JAN06*	
ENRM3982	Start Barge Unloader Area Construction	0	09MAR06*	
ENRM3978	Start AM12 FGD Construction (stck/abs fndn)	0	11JUL06*	
ENRM3984	Start Landfill Construction - Area C	0	22AUG06*	
ENRM3980	Start AM12 Stack Shell Construction	0	31OCT06*	
ENRM4288	Landfill property is secured	0	29OCT07	
ENRM3986	Start Landfill Construction - New	0	29SEP08*	
AEP09 COE Nationwide Permit #6				
C Common				
ENRM4130	Notification to COE - Permit #6 - Explorit ory Wk	10	12NOV04	25NOV04
ENRM4131	Obtain river boring information	0	26NOV04	
AEP10 COE Section 10/404 Permit & 401 Certification				
C Common				
ENRM4140	Prepare permit application	120	10AUG04A	24JAN05
ENRM4150	Submit application	0	25JAN05	
ENRM4160	Agency review/negotiation	262	25JAN05	25JAN06
ENRM4520	Prepare permit application/conduct field studies	120	04MAR05	18AUG05
ENRM4530	Submit application	0	19AUG05	
ENRM4540	Agency review/negotiation	262	19AUG05	21AUG06
ENRM4170	Receive permit	0	26JAN06	
ENRM4180	Follow-up work	20	26JAN06	22FEB06
ENRM4550	Receive permit	0	22AUG06	
ENRM4560	Follow-up work	20	22AUG06	18SEP06
ENRM4290	Prepare permit application/conduct field studies	120	12APR07	26SEP07
ENRM4300	Submit application	0	27SEP07	
ENRM4310	Agency review/negotiation	262	27SEP07	26SEP08
ENRM4320	Receive permit	0	29SEP08	
ENRM4330	Follow-up work	20	29SEP08	24OCT08



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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

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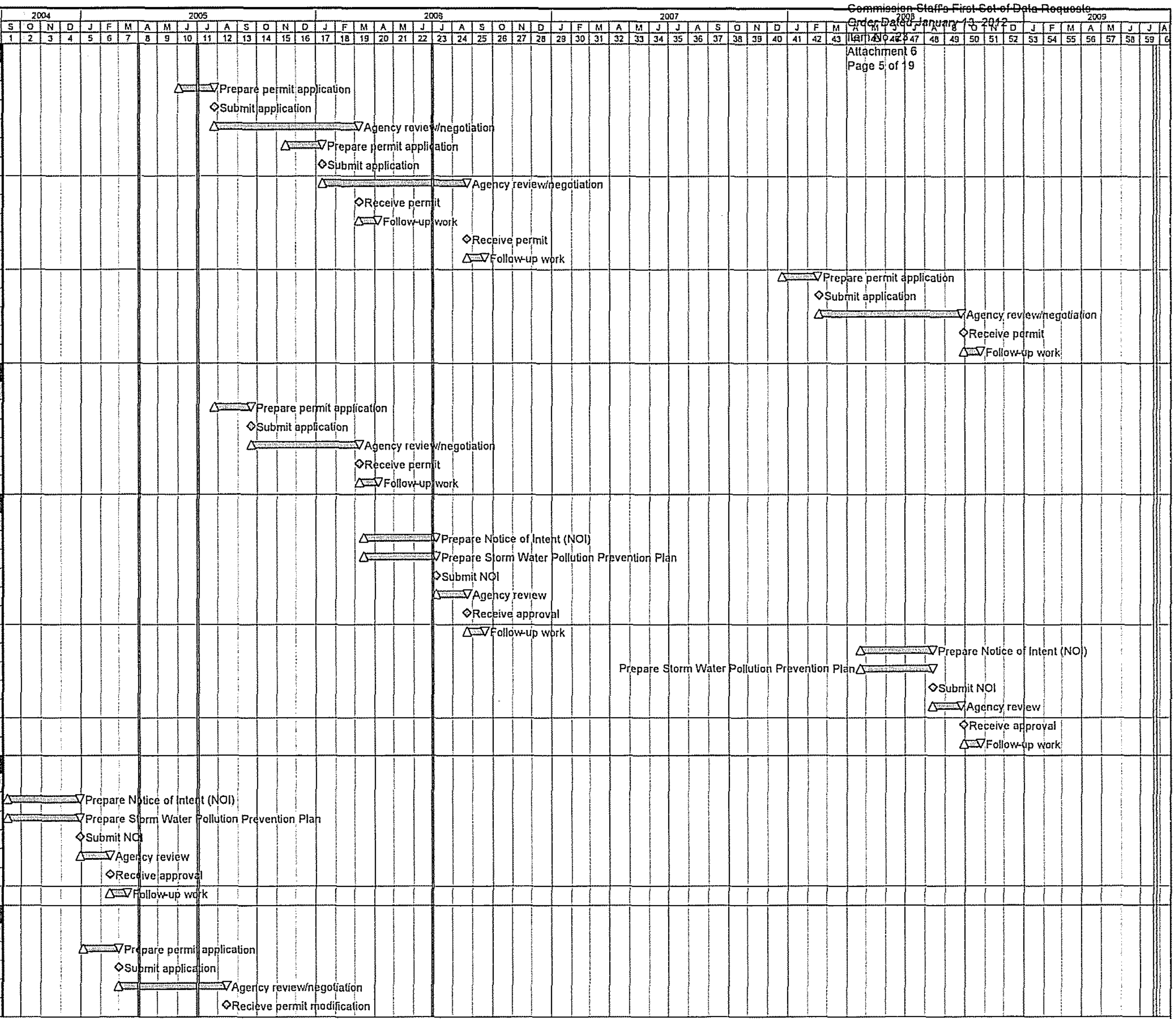
Act. ID	Activity Description	Orig Dur	Start	Finish
AEP11 Public Lands Corporation Permit (WV only)				
C Common				
ENRM4190	Prepare permit application	40	02JUN05	27JUL05
ENRM4200	*Submit application*	0	28JUL05	
ENRM4210	Agency review/negotiation	160	28JUL05	08MAR06
ENRM4570	Prepare permit application	40	15NOV05	09JAN06
ENRM4580	Submit application	0	10JAN06	
ENRM4590	Agency review/negotiation	160	10JAN06	21AUG06
ENRM4220	*Receive permit*	0	09MAR06	
ENRM4230	Follow-up work	20	09MAR06	05APR06
ENRM4600	Receive permit	0	22AUG06	
ENRM4610	Follow-up work	20	22AUG06	18SEP06
ENRM4400	Prepare permit application	40	24DEC07	15FEB08
ENRM4410	Submit application	0	18FEB08	
ENRM4420	Agency review/negotiation	160	18FEB08	26SEP08
ENRM4430	Receive permit	0	29SEP08	
ENRM4440	Follow-up work	20	29SEP08	24OCT08
AEP12 State/Local Floodplain Construction Permit				
C Common				
ENRM4240	Prepare permit application	40	28JUL05	21SEP05
ENRM4250	Submit application	0	22SEP05	
ENRM4260	Agency review/negotiation	120	22SEP05	08MAR06
ENRM4270	Receive permit	0	09MAR06	
ENRM4280	Follow-up work	20	09MAR06	05APR06
AEP13 Permit Part of Landfill Permit				
C Common				
ENRM4900	Prepare Notice of Intent (NOI)	80	16MAR06	05JUL06
ENRM4902	Prepare Storm Water Pollution Prevention Plan	80	16MAR06	05JUL06
ENRM4904	Submit NOI	0	06JUL06	
ENRM4906	Agency review	33	*06JUL06*	*21AUG06*
ENRM4908	Receive approval	0	22AUG06	
ENRM4910	Follow-up work	20	22AUG06	18SEP06
ENRM4340	Prepare Notice of Intent (NOI)	80	23APR08	12AUG08
ENRM4350	Prepare Storm Water Pollution Prevention Plan	80	23APR08	12AUG08
ENRM4360	*Submit NOI*	0	13AUG08	
ENRM4370	Agency review	33	13AUG08	26SEP08
ENRM4380	Receive approval	0	29SEP08	
ENRM4390	Follow-up work	20	29SEP08	24OCT08
AEP14 General Storm Water Construction Permit				
C Common				
ENRM4800	Prepare Notice of Intent (NOI)	80	09SEP04	29DEC04
ENRM4810	Prepare Storm Water Pollution Prevention Plan	80	09SEP04	29DEC04
ENRM4820	Submit NOI	0	30DEC04	
ENRM4830	Agency review	33	30DEC04	14FEB05
ENRM4840	Receive approval	0	15FEB05	
ENRM4850	Follow-up work	20	15FEB05	14MAR05
AEP15 NPDES Modification				
C Common				
ENRM4020	Prepare permit application	40	04JAN05	28FEB05
ENRM4030	Submit application	0	01MAR05	
ENRM4040	Agency review/negotiation	120	01MAR05	15AUG05
ENRM4050	Recieve permit modification	0	16AUG05	



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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

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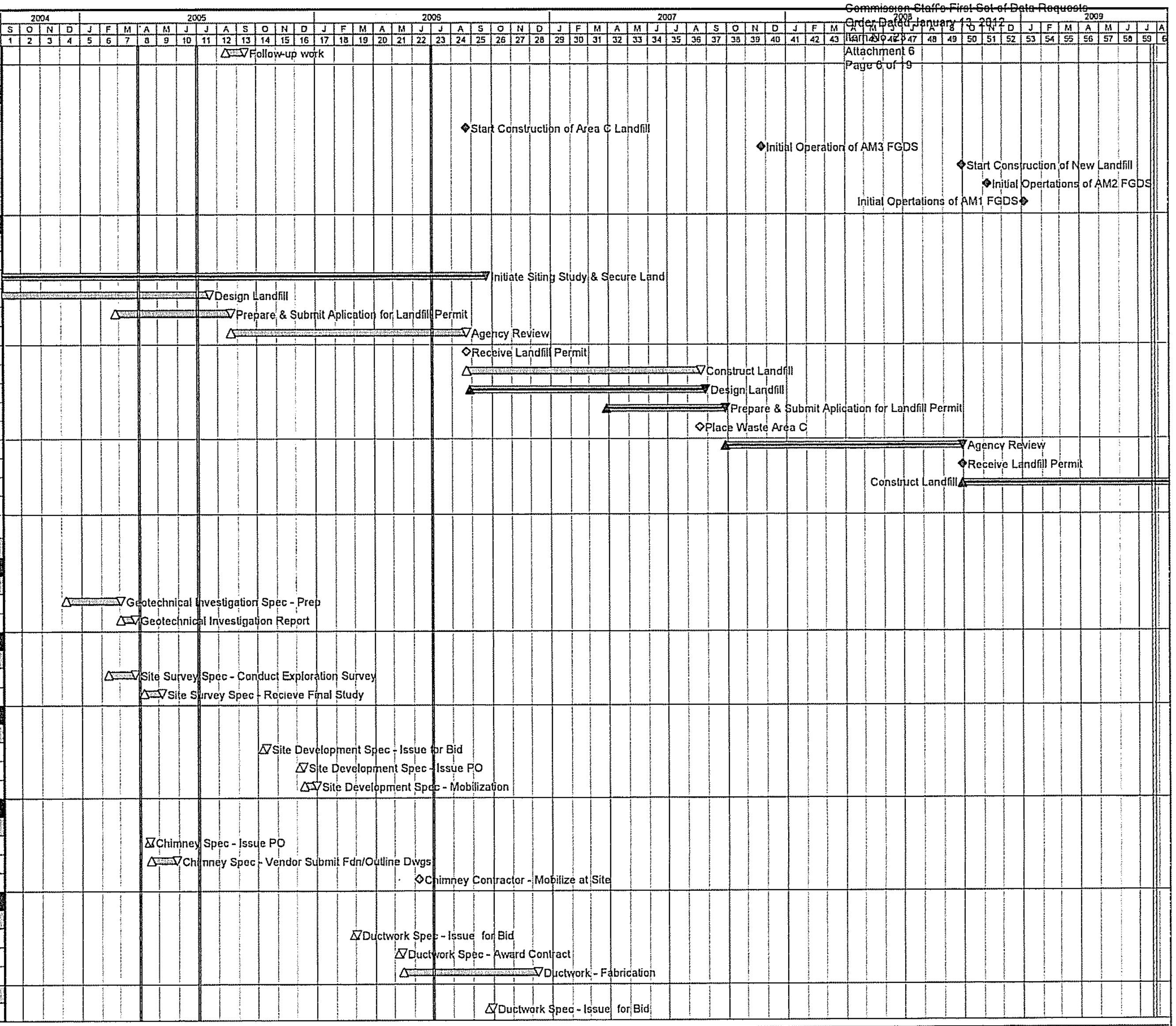
Act. ID	Activity Description	Orig Dur	Start	Finish
ENRM4060	Follow-up work	20	16AUG05	12SEP05
WST WASTE ISSUES/GEOTECH				
AEP16 Preliminary Milestones				
C Common				
AM123N001	Start Construction of Area C Landfill	0	22AUG06*	
AM123N002	Initial Operation of AM3 FGDS	0	25NOV07*	
AM123C001	Start Construction of New Landfill	0	29SEP08*	
AM123C003	Initial Opertations of AM2 FGDS	0	08NOV08*	
AM123C002	Initial Opertations of AM1 FGDS	0	04JAN09*	
AEP17 Permit/Construct				
C Common				
AM123N0100	Evaluate Existing Landfill	84	24MAR04A	19JUL04A
AM123C0100	Initiate Siting Study & Secure Land	575	12JUL04A	22SEP06
AM123N0200	Design Landfill	262	19JUL04A	19JUL05
AM123N0300	Prepare & Submit Aplication for Landfill Permit	128	24FEB05	22AUG05
AM123N0400	Agency Review	262	22AUG05	22AUG06
AM123N0500	Receive Landfill Permit	0	22AUG06	
AM123N0600	Construct Landfill	260	22AUG06	20AUG07
AM123C0200	Design Landfill	262	28AUG06	28AUG07
AM123C0300	Prepare & Submit Aplication for Landfill Permit	133	28MAR07	28SEP07
AM123N0800	Place Waste Area C	0	20AUG07	
AM123C0400	Agency Review	262	28SEP07	29SEP08
AM123C0500	Receive Landfill Permit	0	29SEP08	
AM123C0600	Construct Landfill	262	29SEP08	29SEP09
AM123C0800	Place Waste New Landfill	0	29SEP09	
02 PROCUREMENT				
SP CIVIL / STRUCTURAL PROCUREMENT				
D800 Soil Boring/Testing Spec				
C Common				
END800.05	Geotechnical Investigation Spec - Prep	60	08DEC04	01MAR05
END800.20	Geotechnical Investigation Report	18	02MAR05	25MAR05
D810 Topographic Survey				
C Common				
END810.20	Site Survey Spec - Conduct Exploration Survey	30	11FEB05	24MAR05
END810.40	Site Survey Spec - Recieve Final Study	20	08APR05	05MAY05
D815 Initial Site Development Spec				
C Common				
END815.30	Site Development Spec - Issue for Bid	5	10OCT05	14OCT05
END815.60	Site Development Spec - Issue PO	5	05DEC05	09DEC05
END815.9M	Site Development Spec - Mobilization	15	12DEC05	30DEC05
D820 Chimney & Liner Supply & Erection Spec				
C Common				
END820.60	Chimney Spec - Issue PO	2	14APR05	15APR05*
END820.70	Chimney Spec - Vendor Submit Fdn/Outline Dwgs	30	18APR05	27MAY05
END820.9M	Chimney Contractor - Mobilize at Site	0		07JUN06
D830 Ductwork Fabrication Spec				
3 Unit 3				
END830.30	Ductwork Spec - Issue for Bid	5	27FEB06	03MAR06
END830.60	Ductwork Spec - Award Contract	5	08MAY06	12MAY06
END830.99	Ductwork - Fabrication	150	15MAY06	08DEC06
1 Unit 1				
E1D830.30	Ductwork Spec - Issue for Bid	5	25SEP06	29SEP06



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Schedule Summary
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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

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22OCT04	Initial Draft	HJA	
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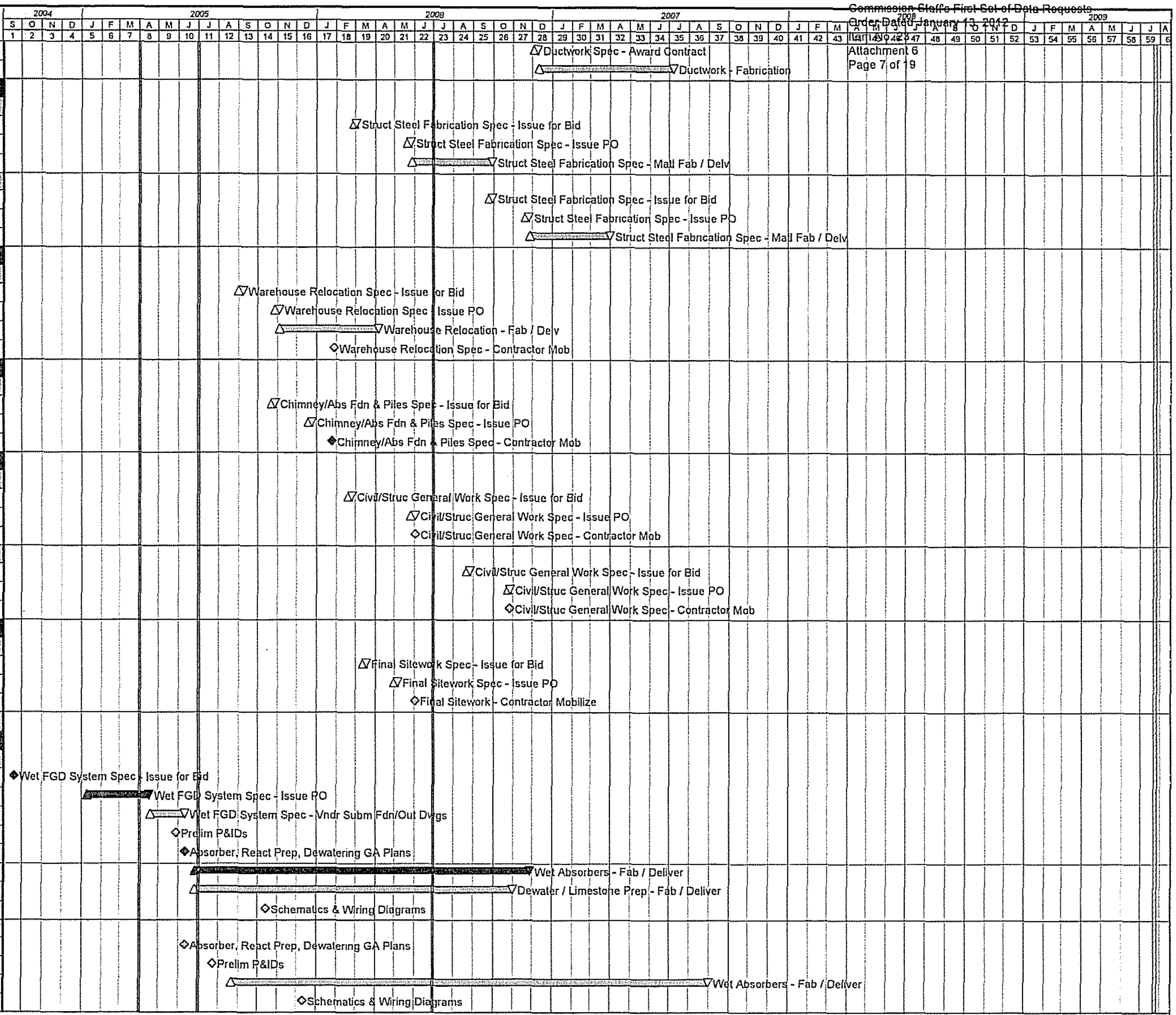
Act. ID	Activity Description	Orig Dur	Start	Finish
E1D830.60	Ductwork Spec - Award Contract	5	04DEC06	08DEC06
E1D830.99	Ductwork - Fabrication	150	11DEC06	06JUL07
D840 Structural Steel Fabrication Spec				
3 Unit 3				
END840.30	Struct Steel Fabrication Spec - Issue for Bid	5	27FEB06	03MAR06
END840.60	Struct Steel Fabrication Spec - Issue PO	5	22MAY06	26MAY06
END840.99	Struct Steel Fabrication Spec - Matl Fab / Delv	90	29MAY06	29SEP06
1 Unit 1				
E1D840.30	Struct Steel Fabrication Spec - Issue for Bid	5	25SEP06	29SEP06
E1D840.60	Struct Steel Fabrication Spec - Issue PO	5	20NOV06	24NOV06
E1D840.99	Struct Steel Fabrication Spec - Matl Fab / Delv	90	27NOV06	30MAR07
D850 Pre-Engineered Buildings Spec				
C Common				
END850.30	Warehouse Relocation Spec - Issue for Bid	5	02SEP05	08SEP05
END850.60	Warehouse Relocation Spec - Issue PO	5	28OCT05	03NOV05
END850.99	Warehouse Relocation - Fab / Delv	110	04NOV05	06APR06
END850.9M	Warehouse Relocation Spec - Contractor Mob	0	27JAN06	
D910 Chimney/Absorber Area Foundations and Piles				
C Common				
END910.30	Chimney/Abs Fdn & Piles Spec - Issue for Bid	5	24OCT05	28OCT05
END910.60	Chimney/Abs Fdn & Piles Spec - Issue PO	5	19DEC05	23DEC05
END910.9M	Chimney/Abs Fdn & Piles Spec - Contractor Mob	0		24JAN06
D920 Civil/Struct General Work Spec				
3 Unit 3				
END920.30	Civil/Struc General Work Spec - Issue for Bid	5	20FEB06	24FEB06
END920.60	Civil/Struc General Work Spec - Issue PO	5	26MAY06	01JUN06
END920.9M	Civil/Struc General Work Spec - Contractor Mob	0		01JUN06
1 Unit 1				
E1D920.30	Civil/Struc General Work Spec - Issue for Bid	5	21AUG06	25AUG06
E1D920.60	Civil/Struc General Work Spec - Issue PO	5	23OCT06	27OCT06
E1D920.9M	Civil/Struc General Work Spec - Contractor Mob	0		27OCT06
D930 Rivers Cells for Barge Unloading Spec				
C Common				
END930.30	Final Sitework Spec - Issue for Bid	5	13MAR06	17MAR06
END930.60	Final Sitework Spec - Issue PO	5	01MAY06	05MAY06
END930.9M	Final Sitework - Contractor Mobilize	0		02JUN06
MP MECHANICAL PROCUREMENT				
N800 Wet FGD System Spec				
C Common				
AEN800.30	Wet FGD System Spec - Issue for Bid	0		17SEP04
AEN800.60	Wet FGD System Spec - Issue PO	70	10JAN05	15APR05
ENN800.70	Wet FGD System Spec - Vndr Subm Fdn/Out Dwgs	40	18APR05	10JUN05
ENN800.K	Prelim P&IDs	0		27MAY05
ENN800.J	Absorber, React Prep, Dewatering GA Plans	0		10JUN05
ENN800.98	Wet Absorbers - Fab / Deliver	371	27JUN05	27NOV06
ENN800.99	Dewater / Limestone Prep - Fab / Deliver	352	27JUN05	31OCT06
ENN800.AF	Schematics & Wiring Diagrams	0		14OCT05
1 Unit 1				
E1N800.J	Absorber, React Prep, Dewatering GA Plans	0		10JUN05
E1N800.K	Prelim P&IDs	0		22JUL05
E1N800.98	Wet Absorbers - Fab / Deliver	530	22AUG05	31AUG07
E1N800.AF	Schematics & Wiring Diagrams	0		09DEC05



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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

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01NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
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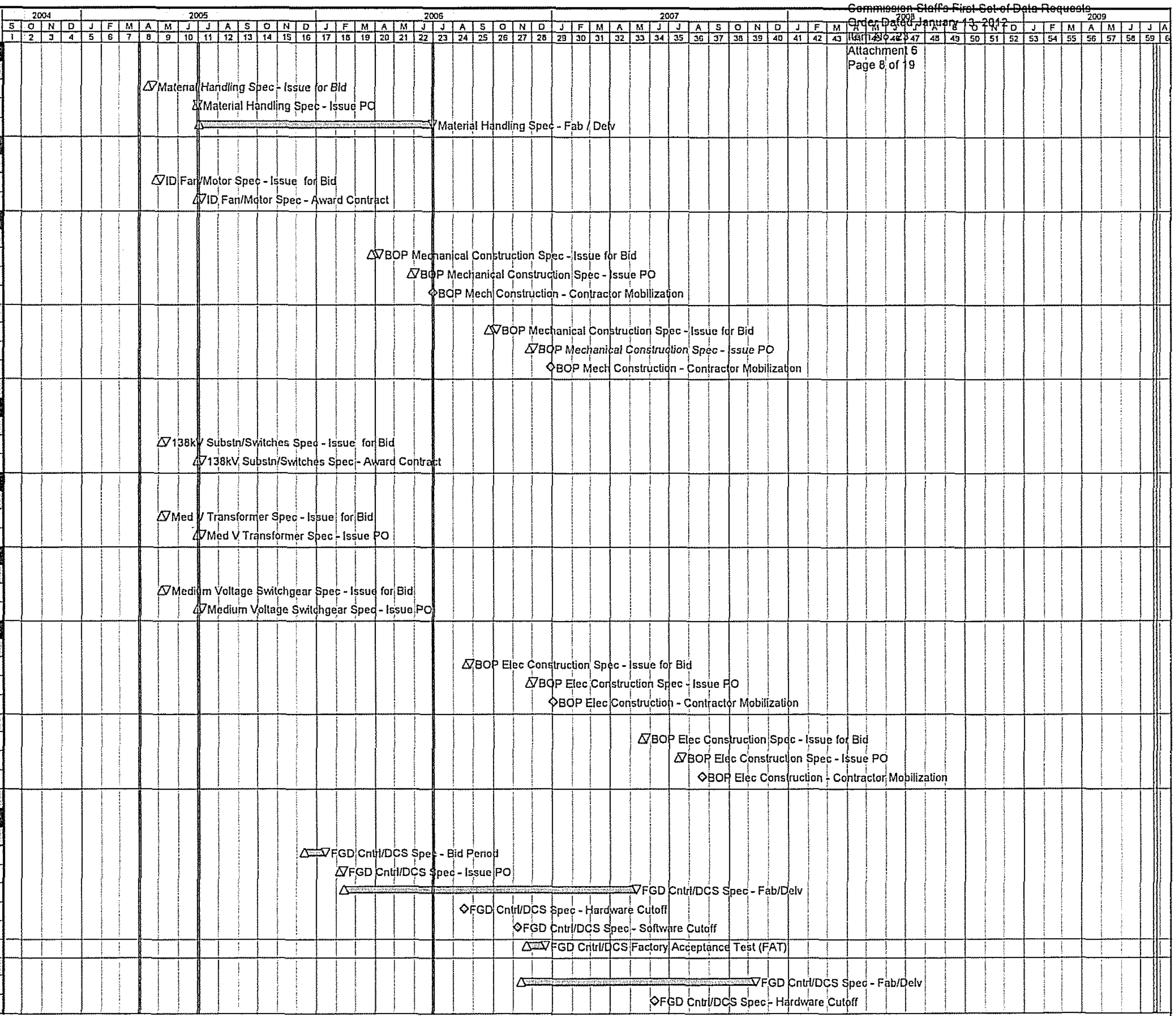
Act. ID	Activity Description	Orig Dur	Start	Finish
N810 Material Handling System Spec				
C Common				
ENN810.30	Material Handling Spec - Issue for Bid	5	14APR05	20APR05
ENN810.60	Material Handling Spec - Issue PO	2	30JUN05	01JUL05
ENN810.99	Material Handling Spec - Fab / Delv	260	04JUL05	30JUN06
N815 ID Fan/Motor Spec				
C Common				
ENN815.30	ID Fan/Motor Spec - Issue for Bid	5	27APR05	03MAY05
ENN815.60	ID Fan/Motor Spec - Award Contract	5	29JUN05	05JUL05
N900 General Installation Spec-Mechanical				
3 Unit 3				
ENN900.30	BOP Mechanical Construction Spec - Issue for Bid	10	27MAR06	07APR06
ENN900.60	BOP Mechanical Construction Spec - Issue PO	5	29MAY06	02JUN06
ENN900.9M	BOP Mech Construction - Contractor Mobilization	0		30JUN06
1 Unit 1				
E1N900.30	BOP Mechanical Construction Spec - Issue for Bid	10	25SEP06	06OCT06
E1N900.60	BOP Mechanical Construction Spec - Issue PO	5	27NOV06	01DEC06
E1N900.9M	BOP Mech Construction - Contractor Mobilization	0		29DEC06
EP ELECTRICAL PROCUREMENT				
F810 138kV Substation/Switches Spec				
C Common				
ENF810.30	138kV Substn/Switches Spec - Issue for Bid	5	05MAY05	11MAY05
ENF810.60	138kV Substn/Switches Spec - Award Contract	5	29JUN05	05JUL05*
F820 Medium Voltage Transformer Spec				
C Common				
ENF820.30	Med V Transformer Spec - Issue for Bid	5	05MAY05	11MAY05
ENF820.60	Med V Transformer Spec - Issue PO	5	29JUN05	05JUL05*
F830 Medium Voltage Switchgear Spec				
C Common				
ENF830.30	Medium Voltage Switchgear Spec - Issue for Bid	5	05MAY05	11MAY05
ENF830.60	Medium Voltage Switchgear Spec - Issue PO	5	29JUN05	05JUL05*
F900 General Electrical Installation Spec				
3 Unit 3				
ENF900.30	BOP Elec Construction Spec - Issue for Bid	5	21AUG06	25AUG06
ENF900.60	BOP Elec Construction Spec - Issue PO	5	27NOV06	01DEC06
ENF900.9M	BOP Elec Construction - Contractor Mobilization	0		01JAN07
1 Unit 1				
E1F900.30	BOP Elec Construction Spec - Issue for Bid	5	21MAY07	25MAY07
E1F900.60	BOP Elec Construction Spec - Issue PO	5	16JUL07	20JUL07
E1F900.9M	BOP Elec Construction - Contractor Mobilization	0		20AUG07
IP I&C PROCUREMENT				
J810 FGD Ctrl Sys/DCS Spec				
C Common				
ENJ810.40	FGD Cntrl/DCS Spec - Bid Period	25	12DEC05	13JAN06
ENJ810.60	FGD Cntrl/DCS Spec - Issue PO	5	06FEB06	10FEB06
ENJ810.99	FGD Cntrl/DCS Spec - Fab/Delv	325	13FEB06	11MAY07
ENJ810.92	FGD Cntrl/DCS Spec - Hardware Cutoff	0		16AUG06
ENJ810.96	FGD Cntrl/DCS Spec - Software Cutoff	0		08NOV06
ENJ810.98	FGD Cntrl/DCS Factory Acceptance Test (FAT)	22	22NOV06	21DEC06
1 Unit 1				
E1J810.99	FGD Cntrl/DCS Spec - Fab/Delv	260	14NOV06	12NOV07
E1J810.92	FGD Cntrl/DCS Spec - Hardware Cutoff	0		08JUN07



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Schedule Summary
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American Electric Power
AMOS FGD Retrofit Projectect
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Sargent & Lundy^{LLC}

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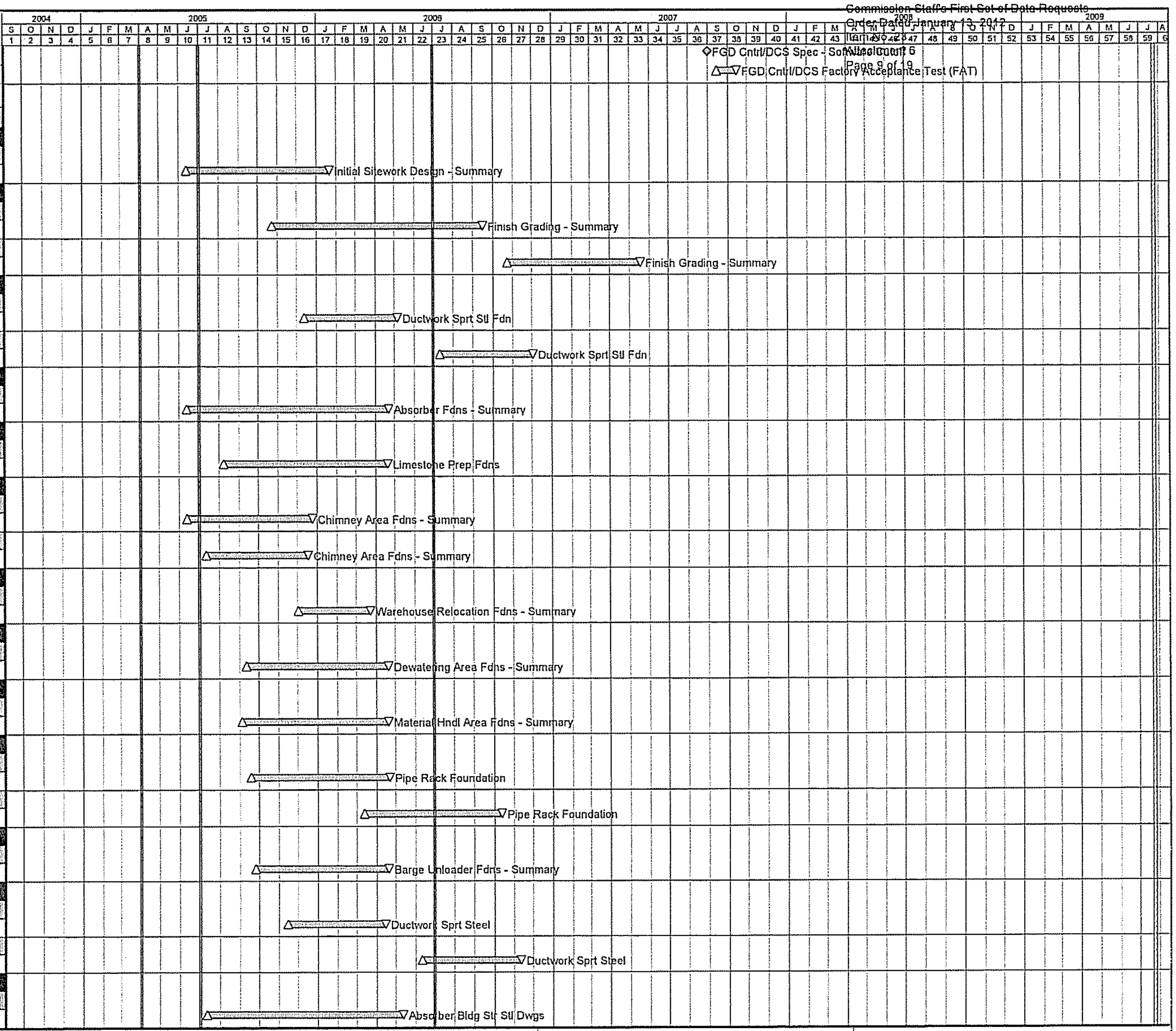
Act. ID	Activity Description	Orig Dur	Start	Finish
E1J810.96	FGD Cntrl/DCS Spec - Software Cutoff	0		31AUG07
E1J810.98	FGD Cntrl/DCS Factory Acceptance Test (FAT)	22	14SEP07	15OCT07
01 ENGINEERING				
SC CIVIL / STRUCTURAL DESIGN				
C010 Initial Sitework				
C Common				
ENC010.00	Initial Sitework Design - Summary	160	13JUN05	20JAN06
C080 Finish Grading				
3 Unit 3				
ENC080.00	Finish Grading - Summary	235	24OCT05	15SEP06
1 Unit 1				
E1C080.00	Finish Grading - Summary	150	23OCT06	18MAY07
C210 Duct Sprt Steel Fdn Dwgs				
3 Unit 3				
ENC210.00	Ductwork Sprt Stl Fdn	105	12DEC05	05MAY06
1 Unit 1				
E1C210.00	Ductwork Sprt Stl Fdn	105	10JUL06	01DEC06
C215 Absorber Fdn				
3 Unit 3				
ENC215.00	Absorber Fdns - Summary	225	13JUN05	21APR06
C225 Limestone Prep Area Fdn Dwgs				
C Common				
ENC225.00	Limestone Prep Fdns	184	08AUG05	20APR06
C230 Chimney Fdn Dwg				
3 Unit 3				
ENC230.00	Chimney Area Fdns - Summary	140	13JUN05	23DEC05
1 Unit 1				
E1C230.00	Chimney Area Fdns - Summary	115	11JUL05	16DEC05
C234 Warehouse Relocation Fdns				
C Common				
ENC234.00	Warehouse Relocation Fdns - Summary	80	02DEC05	23MAR06
C240 Gypsum Dewatering Area Fdn Dwgs				
C Common				
ENC240.00	Dewatering Area Fdns - Summary	159	12SEP05	20APR06
C260 Material Handling Area Fdn Dwgs				
C Common				
ENC260.00	Material Hndl Area Fdns - Summary	164	05SEP05	20APR06
C270 Pipe Rack Fnd Dwgs				
3 Unit 3				
ENC270.00	Pipe Rack Foundation	155	19SEP05	21APR06
1 Unit 1				
E1C270.00	Pipe Rack Foundation	155	13MAR06	13OCT06
C285 Barge Unloader Fdns				
C Common				
ENC285.00	Barge Unloader Fdns - Summary	149	26SEP05	20APR06
C310 Ductwork Support Steel Dwgs				
3 Unit 3				
ENC310.00	Ductwork Sprt Steel	110	14NOV05	14APR06
1 Unit 1				
E1C310.00	Ductwork Sprt Steel	110	12JUN06	10NOV06
C315 Absorber Bldg Steel Dwgs				
3 Unit 3				
ENC315.00	Absorber Bldg Str Stl Dwgs	220	11JUL05	12MAY06



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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	N/A	
01NOV04	Preliminary Issue	DJG	
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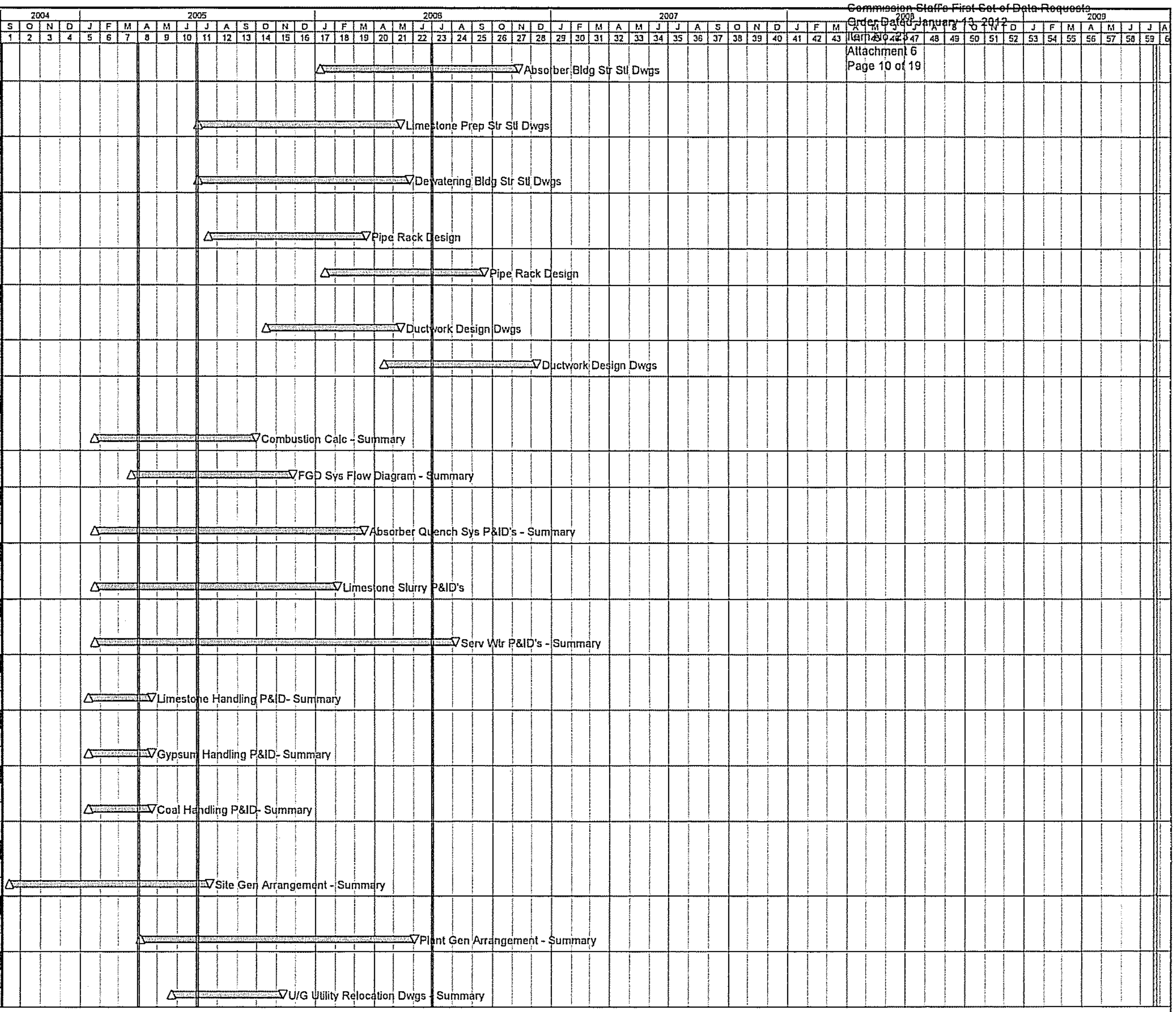
Act. ID	Activity Description	Orig Dur	Start	Finish
1 Unit 1				
E1C315.00	Absorber Bldg Str Stl Dwgs	220	09JAN06	10NOV06
C325 Limestone Prep Bldg Steel Dwgs				
C Common				
ENC325.00	Limestone Prep Str Stl Dwgs	225	04JUL05	12MAY06
C340 Dewatering Bldg Steel Dwgs				
C Common				
ENC340.00	Dewatering Bldg Str Stl Dwgs	235	04JUL05	26MAY06
C370 Pipe Rack Steel Dwgs				
3 Unit 3				
ENC370.00	Pipe Rack Design	176	18JUL05	20MAR06
1 Unit 1				
E1C370.00	Pipe Rack Design	176	16JAN06	18SEP06
C410 Detail Ductwork Design				
3 Unit 3				
ENC410.00	Ductwork Design Dwgs	150	17OCT05	12MAY06
1 Unit 1				
E1C410.00	Ductwork Design Dwgs	170	17APR06	08DEC06
ME MECHANICAL ENGINEERING				
M110 FGD Sys Flow Diagram				
3 Unit 3				
ENM003.00	Combustion Calc - Summary	180	24JAN05	30SEP05
1 Unit 1				
E1M110.00	FGD Sys Flow Diagram - Summary	180	21MAR05	25NOV05
M115 Absorber Bleed Slurry Sys P&ID				
C Common				
ENM115.00	Absorber Quench Sys P&ID's - Summary	299	24JAN05	16MAR06
M125 Limestone Slurry System P&ID				
C Common				
ENM125.00	Limestone Slurry P&ID's	270	24JAN05	03FEB06
M154 Service Water P&IDs				
C Common				
ENM154.00	Serv Wtr P&ID's - Summary	400	24JAN05	04AUG06
M160 Limestone Handling Flow Diagram				
C Common				
ENM160.00	Limestone Handling P&ID- Summary	70	13JAN05	20APR05
M170 Gypsum Handling Flow Diagram				
C Common				
ENM170.00	Gypsum Handling P&ID- Summary	70	13JAN05	20APR05
M175 Coal Handling Flow Diagram				
C Common				
ENM175.00	Coal Handling P&ID- Summary	70	13JAN05	20APR05
MD MECHANICAL DESIGN				
M001 Site Arrangement Dwgs				
C Common				
ENM001.00	Site Gen Arrangement - Summary	223	13SEP04	20JUL05
M010 Plant General Arrangements				
3 Unit 3				
ENM010.00	Plant Gen Arrangement - Summary	305	04APR05	02JUN06
M015 Underground Utility Relocation Dwgs				
3 Unit 3				
ENM015.00	U/G Utility Relocation Dwgs - Summary	125	23MAY05	11NOV05



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Sargent & Lundy LLC

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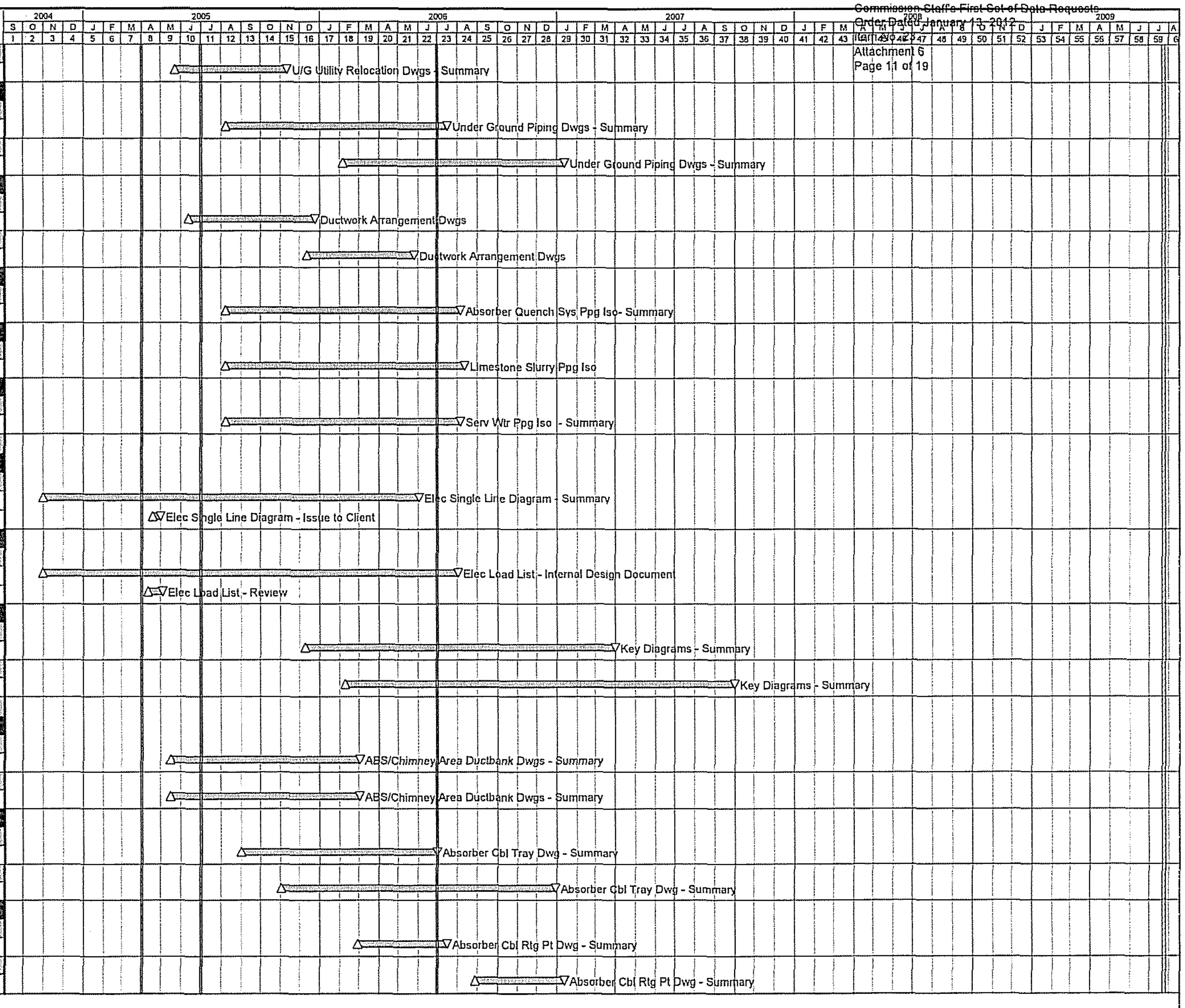
Act. ID	Activity Description	Orig Dur	Start	Finish
1 Unit 1				
E1M015.00	U/G Utility Relocation Dwgs - Summary	125	23MAY05	11NOV05
M080 Underground Piping Dwgs				
3 Unit 3				
ENM080.00	Under Ground Piping Dwgs - Summary	245	08AUG05	14JUL06
1 Unit 1				
E1M080.00	Under Ground Piping Dwgs - Summary	245	06FEB06	12JAN07
M210 Ductwork Arrangement Dwgs				
3 Unit 3				
ENM210.00	Ductwork Arrangement Dwgs	140	13JUN05	23DEC05
1 Unit 1				
E1M210.00	Ductwork Arrangement Dwgs	120	12DEC05	26MAY06
M215 Absorber Bleed Slurry Sys Ppg Dsg				
C Common				
ENM215.00	Absorber Quench Sys Ppg Iso- Summary	260	08AUG05	04AUG06
M225 Limestone Slurry System Ppg Dsg				
C Common				
ENM225.00	Limestone Slurry Ppg Iso	265	08AUG05	11AUG06
M254 Service Water System Ppg Dsg				
C Common				
ENM254.00	Serv Wtr Ppg Iso - Summary	260	08AUG05	04AUG06
EE ELECTRICAL ENGINEERING				
E001 Single Line Diagram				
3 Unit 3				
ENE001.00	Elec Single Line Diagram - Summary	414	01NOV04	01JUN06
ENE001.20	Elec Single Line Diagram - Issue to Client	10	18APR05	29APR05
E003 Elec Load List (Internal Design Doc)				
3 Unit 3				
ENE003.00	Elec Load List - Internal Design Document	457	01NOV04	01AUG06
ENE003.15	Elec Load List - Review	15	12APR05	02MAY05
E004 Key Diagrams				
3 Unit 3				
ENE004.00	Key Diagrams - Summary	342	08DEC05	30MAR07
1 Unit 1				
E1E004.00	Key Diagrams - Summary	429	08FEB06	01OCT07
ED ELECTRICAL DESIGN				
E010 FGD/Chimney Area Ductbank Dwgs				
3 Unit 3				
ENE010.00	ABS/Chimney Area Ductbank Dwgs - Summary	209	16MAY05	02MAR06
1 Unit 1				
E1E010.00	ABS/Chimney Area Ductbank Dwgs - Summary	209	16MAY05	02MAR06
E115 Absorber Area Cable Tray Dwgs				
3 Unit 3				
ENE115.00	Absorber Cbl Tray Dwg - Summary	217	01SEP05	30JUN06
1 Unit 1				
E1E115.00	Absorber Cbl Tray Dwg - Summary	303	02NOV05	29DEC06
E215 Absorber Area Tray Routing Dwgs				
3 Unit 3				
ENE215.00	Absorber Cbl Rtg Pt Dwg - Summary	100	27FEB06	14JUL06
1 Unit 1				
E1E215.00	Absorber Cbl Rtg Pt Dwg - Summary	100	28AUG06	12JAN07



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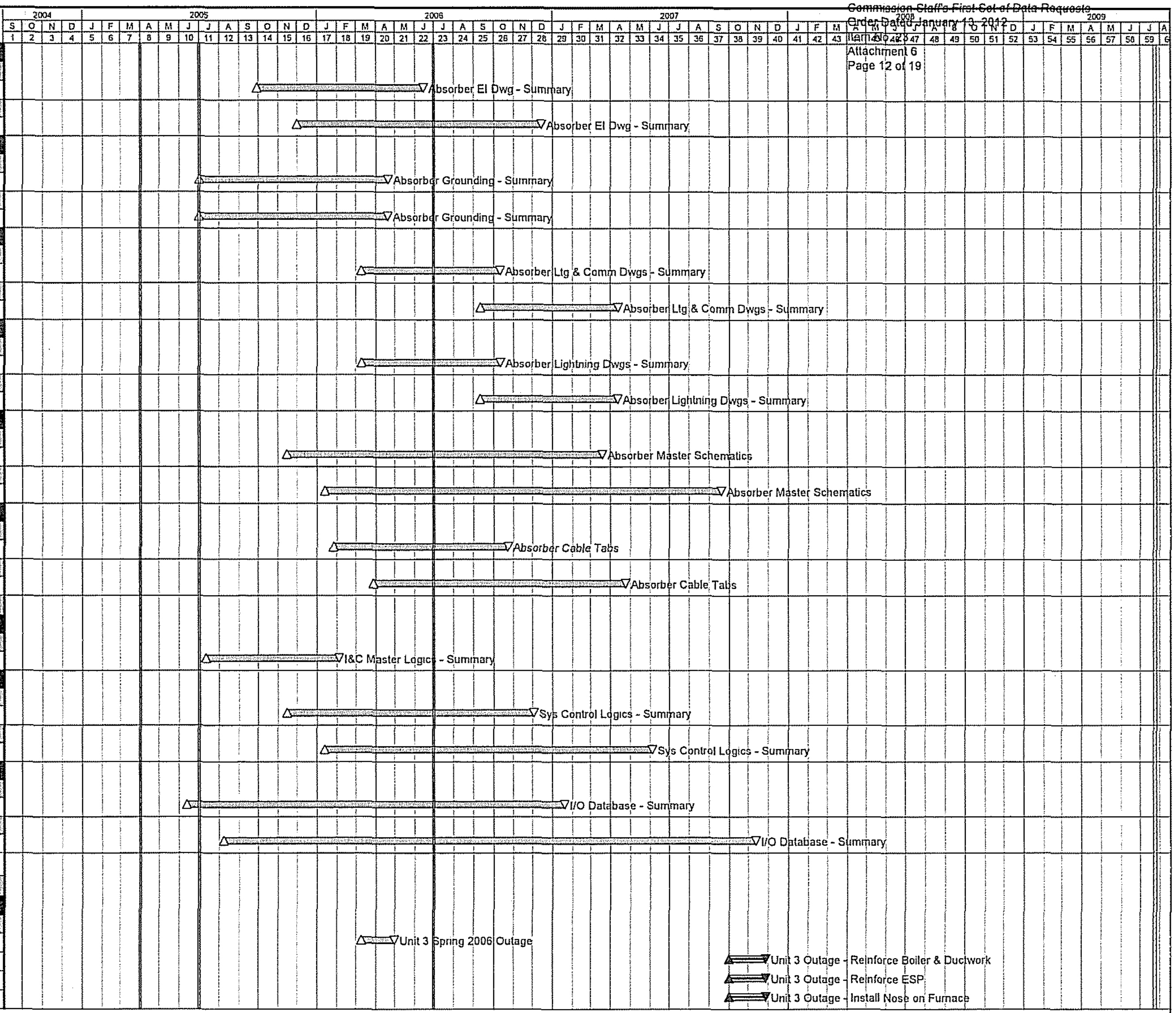
Act. ID	Activity Description	Orig Dur	Start	Finish
E315 Absorber Area Elec Inst Dwgs				
3 Unit 3				
ENE315.00	Absorber El Dwg - Summary	185	29SEP05	14JUN06
1 Unit 1				
E1E315.00	Absorber El Dwg - Summary	272	30NOV05	14DEC06
E415 Absorber Area Grounding Dwgs				
3 Unit 3				
ENE415.00	*Absorber Grounding - Summary*	210	01JUL05	20APR06
1 Unit 1				
E1E415.00	Absorber Grounding - Summary	210	01JUL05	20APR06
E615 Absorber Area Lighting Dwgs				
3 Unit 3				
ENE615.00	Absorber Ltg & Comm Dwgs - Summary	154	10MAR06	11OCT06
1 Unit 1				
E1E615.00	Absorber Ltg & Comm Dwgs - Summary	154	11SEP06	12APR07
E616 Absorber Lightning Dwgs				
3 Unit 3				
ENE616.00	*Absorber Lightning Dwgs - Summary*	154	*10MAR06*	11OCT06
1 Unit 1				
E1E616.00	Absorber Lightning Dwgs - Summary	154	11SEP06	12APR07
E7Y1D Aborber Master Schematics				
3 Unit 3				
ENE7Y1.00	Absorber Master Schematics	351	14NOV05	19MAR07
1 Unit 1				
E1E7Y1.00	Absorber Master Schematics	438	13JAN06	18SEP07
E8Y1D Absorber Cable Tabs				
3 Unit 3				
ENE8Y1.00	Absorber Cable Tabs	193	26JAN06	23OCT06
1 Unit 1				
E1E8Y1.00	Absorber Cable Tabs	280	29MAR06	24APR07
IC I&C ENGINEERING / DESIGN				
J080 I&C Master Logics				
C Common				
ENJ080.00	I&C Master Logics - Summary	150	11JUL05	03FEB06
J100 System Control Logics				
3 Unit 3				
ENJ100.00	Sys Control Logics - Summary	275	14NOV05	01DEC06
1 Unit 1				
E1J100.00	Sys Control Logics - Summary	362	13JAN06	04JUN07
J400 DCS I/O Database				
3 Unit 3				
ENJ400.00	I/O Database - Summary	420	13JUN05	19JAN07
1 Unit 1				
E1J400.00	I/O Database - Summary	591	08AUG05	12NOV07
03 CONSTRUCTION				
S3 PRE-COMMISSIONING / START-UP UNIT 3				
SU98 System Start-up, Testing & Checkout				
3 Unit 3				
CN90100	Unit 3 Spring 2006 Outage	51	11MAR06*	30APR06
CN90210	Unit 3 Outage - Reinforce Boiler & Ductwork	56	02OCT07	26NOV07
CN90220	Unit 3 Outage - Reinforce ESP	56	02OCT07	26NOV07
CN90230	Unit 3 Outage - Install Nose on Furnace	56	02OCT07	26NOV07



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Sargent & Lundy LLC

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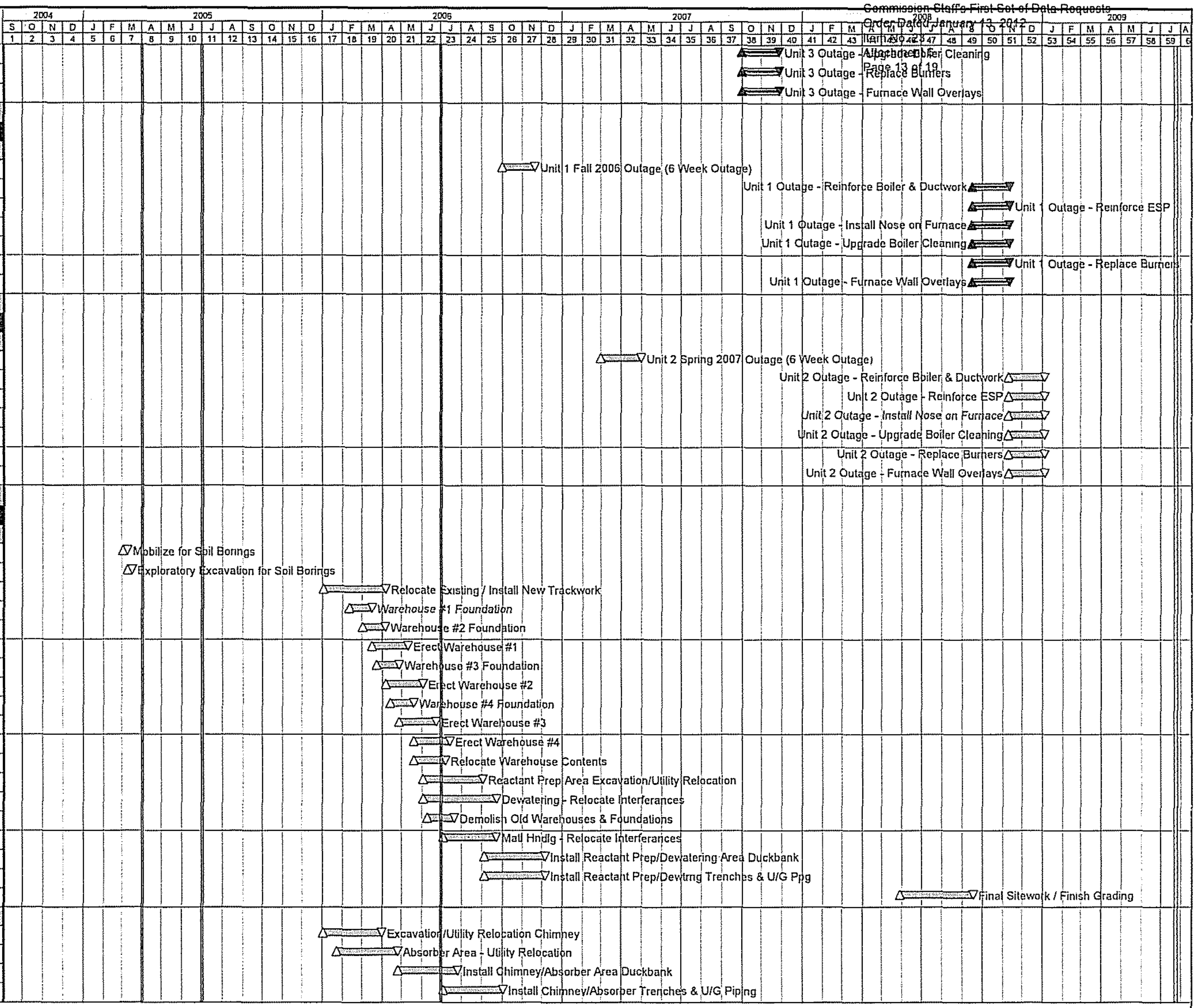
Act. ID	Activity Description	Orig Dur	Start	Finish
CN90240	Unit 3 Outage - Upgrade Boiler Cleaning	56	02OCT07	26NOV07
CN90250	Unit 3 Outage - Replace Burners	56	02OCT07	26NOV07
CN90260	Unit 3 Outage - Furnace Wall Overlays	56	02OCT07	26NOV07
S1 PRE-COMMISSIONING / START-UP UNIT 1				
SU98 System Start-up, Testing & Checkout				
1 Unit 1				
C190100	Unit 1 Fall 2006 Outage (6 Week Outage)	51	01OCT06*	20NOV06
C190210	Unit 1 Outage - Reinforce Boiler & Ductwork	56	16SEP08	10NOV08
C190220	Unit 1 Outage - Reinforce ESP	56	16SEP08	10NOV08
C190230	Unit 1 Outage - Install Nose on Furnace	56	16SEP08	10NOV08
C190240	Unit 1 Outage - Upgrade Boiler Cleaning	56	16SEP08	10NOV08
C190250	Unit 1 Outage - Replace Burners	56	16SEP08	10NOV08
C190260	Unit 1 Outage - Furnace Wall Overlays	56	16SEP08	10NOV08
S2 PRE-COMMISSIONING / START-UP UNIT 2				
SU98 System Start-up, Testing & Checkout				
2 Unit 2				
C290100	Unit 2 Spring 2007 Outage (6 Week Outage)	61	01MAR07*	30APR07
C290210	Unit 2 Outage - Reinforce Boiler & Ductwork	56	10NOV08*	04JAN09
C290220	Unit 2 Outage - Reinforce ESP	56	10NOV08*	04JAN09
C290230	Unit 2 Outage - Install Nose on Furnace	56	10NOV08*	04JAN09
C290240	Unit 2 Outage - Upgrade Boiler Cleaning	56	10NOV08*	04JAN09
C290250	Unit 2 Outage - Replace Burners	56	10NOV08*	04JAN09
C290260	Unit 2 Outage - Furnace Wall Overlays	56	10NOV08*	04JAN09
C3 CONSTRUCTION UNIT 3				
SU01 Initial / Final Site Prep				
C Common				
CN01000	Mobilize for Soil Borings	5	02MAR05	08MAR05
CN01010	Exploratory Excavation for Soil Borings	5	09MAR05	15MAR05
CN10100	Relocate Existing / Install New Trackwork	68	02JAN06	05APR06
CN60110	Warehouse #1 Foundation	25	10FEB06	16MAR06
CN60130	Warehouse #2 Foundation	25	03MAR06	06APR06
CN60120	Erect Warehouse #1	40	17MAR06	11MAY06
CN60150	Warehouse #3 Foundation	25	24MAR06	27APR06
CN60140	Erect Warehouse #2	40	07APR06	01JUN06
CN60170	Warehouse #4 Foundation	25	14APR06	18MAY06
CN60160	Erect Warehouse #3	40	28APR06	22JUN06
CN60180	Erect Warehouse #4	40	19MAY06	13JUL06
CN60190	Relocate Warehouse Contents	35	19MAY06	06JUL06
CN25100	Reactant Prep Area Excavation/Utility Relocation	66	02JUN06	01SEP06
CN40100	Dewatering - Relocate Interferances	80	02JUN06	21SEP06
CN60210	Demolish Old Warehouses & Foundations	30	09JUN06	20JUL06
CN60100	Matl Hndlg - Relocate Interferances	60	03JUL06	22SEP06
CN25110	Install Reactant Prep/Dewatering Area Duckbank	66	04SEP06	04DEC06
CN25120	Install Reactant Prep/Dewtrng Trenches & U/G Ppg	66	04SEP06	04DEC06
CN10900	Final Sitework / Finish Grading	80	29MAY08	17SEP08
3 Unit 3				
CN10110	Excavation/Utility Relocation Chimney	65	02JAN06	31MAR06
CN15100	Absorber Area - Utility Relocation	66	23JAN06	24APR06
CN15110	Install Chimney/Absorber Area Duckbank	66	25APR06	25JUL06
CN15120	Install Chimney/Absorber Trenches & U/G Piping	66	03JUL06	02OCT06



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AMOS FGD Retrofit Projectect
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Sargent & Lundy LLC

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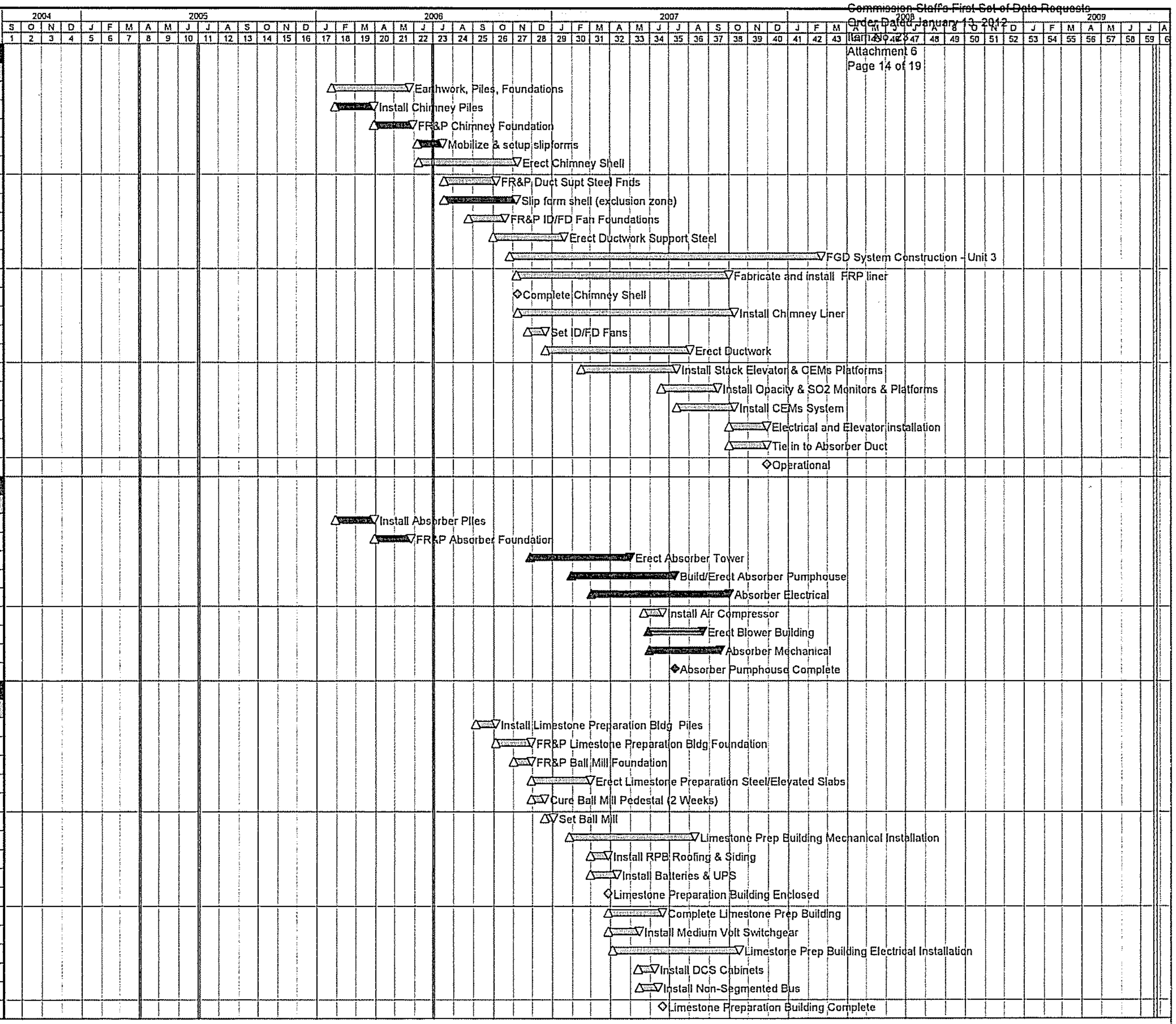
Act. ID	Activity Description	Orig Dur	Start	Finish
SU10 Flue Gas Area / Ductwork Construction/Start-up				
3 Unit 3				
STK1039	Earthwork, Piles, Foundations	86	25JAN06	24MAY06
CN10210	Install Chimney Piles	44	30JAN06	30MAR06
CN10300	FR&P Chimney Foundation	43	31MAR06	30MAY06
STK1040	Mobilize & setup slipforms	29	05JUN06	14JUL06
CN10400	Erect Chimney Shell	110	08JUN06	08NOV06
CN14300	FR&P Duct Supt Steel Fnds	60	17JUL06	06OCT06
STK1050	Slip form shell (exclusion zone)	81	17JUL06	06NOV06
CN12300	FR&P ID/FD Fan Foundations	40	25AUG06	19OCT06
CN14400	Erect Ductwork Support Steel	80	02OCT06	19JAN07
CN120010	FGD System Construction - Unit 3	345	27OCT06*	21FEB08
STK1060	Fabricate and install FRP liner	235	07NOV06	01OCT07
CN10410	Complete Chimney Shell	0		08NOV06
CN10510	Install Chimney Liner	240	09NOV06	10OCT07
CN12400	Set ID/FD Fans	20	24NOV06	21DEC06
CN14610	Erect Ductwork	160	22DEC06	02AUG07
CN10520	Install Stack Elevator & CEMs Platforms	107	14FEB07	12JUL07
CN10600	Install Opacity & SO2 Monitors & Platforms	64	18JUN07	13SEP07
CN11600	Install CEMs System	64	13JUL07	10OCT07
STK1070	Electrical and Elevator installation	42	02OCT07	28NOV07
STK1080	Tie in to Absorber Duct	58	02OCT07	28NOV07
STK1090	Operational	0	29NOV07	
SU15 Absorber Building Area Construction/Start-up				
3 Unit 3				
CN15220	Install Absorber Piles	43	30JAN06	29MAR06
CN15300	FR&P Absorber Foundation	42	30MAR06	26MAY06
CN15400	Erect Absorber Tower	110	28NOV06	30APR07
CN15500	Build/Erect Absorber Pumphouse	115	30JAN07	09JUL07
CN15700	Absorber Electrical	152	02MAR07	01OCT07
CN15610	Install Air Compressor	22	22MAY07	20JUN07
CN15520	Erect Blower Building	60	29MAY07	20AUG07
CN15600	Absorber Mechanical	79	30MAY07	17SEP07
CN15510	Absorber Pumphouse Complete	0		09JUL07
SU25 Limestone Prep Area Construction/Start-up				
C Common				
CN25200	Install Limestone Preparation Bldg Piles	22	04SEP06	03OCT06
CN25300	FR&P Limestone Preparation Bldg Foundation	40	04OCT06	28NOV06
CN25310	FR&P Ball Mill Foundation	20	01NOV06	28NOV06
CN25400	Erect Limestone Preparation Steel/Elevated Slabs	65	29NOV06	27FEB07
CN25420	Cure Ball Mill Pedestal (2 Weeks)	14	29NOV06	18DEC06
CN25430	Set Ball Mill	11	19DEC06	02JAN07
CN25600	Limestone Prep Building Mechanical Installation	140	26JAN07	09AUG07
CN25510	Install RPB Roofing & Siding	20	28FEB07	27MAR07
CN25710	Install Batteries & UPS	30	28FEB07	10APR07
CN25520	Limestone Preparation Building Enclosed	0		27MAR07
CN25530	Complete Limestone Prep Building	61	28MAR07	20JUN07
CN25730	Install Medium Volt Switchgear	35	28MAR07	15MAY07
CN25700	Limestone Prep Building Electrical Installation	140	04APR07	16OCT07
CN25720	Install DCS Cabinets	20	14MAY07	08JUN07
CN25740	Install Non-Segmented Bus	20	16MAY07	12JUN07
CN25540	Limestone Preparation Building Complete	0		20JUN07



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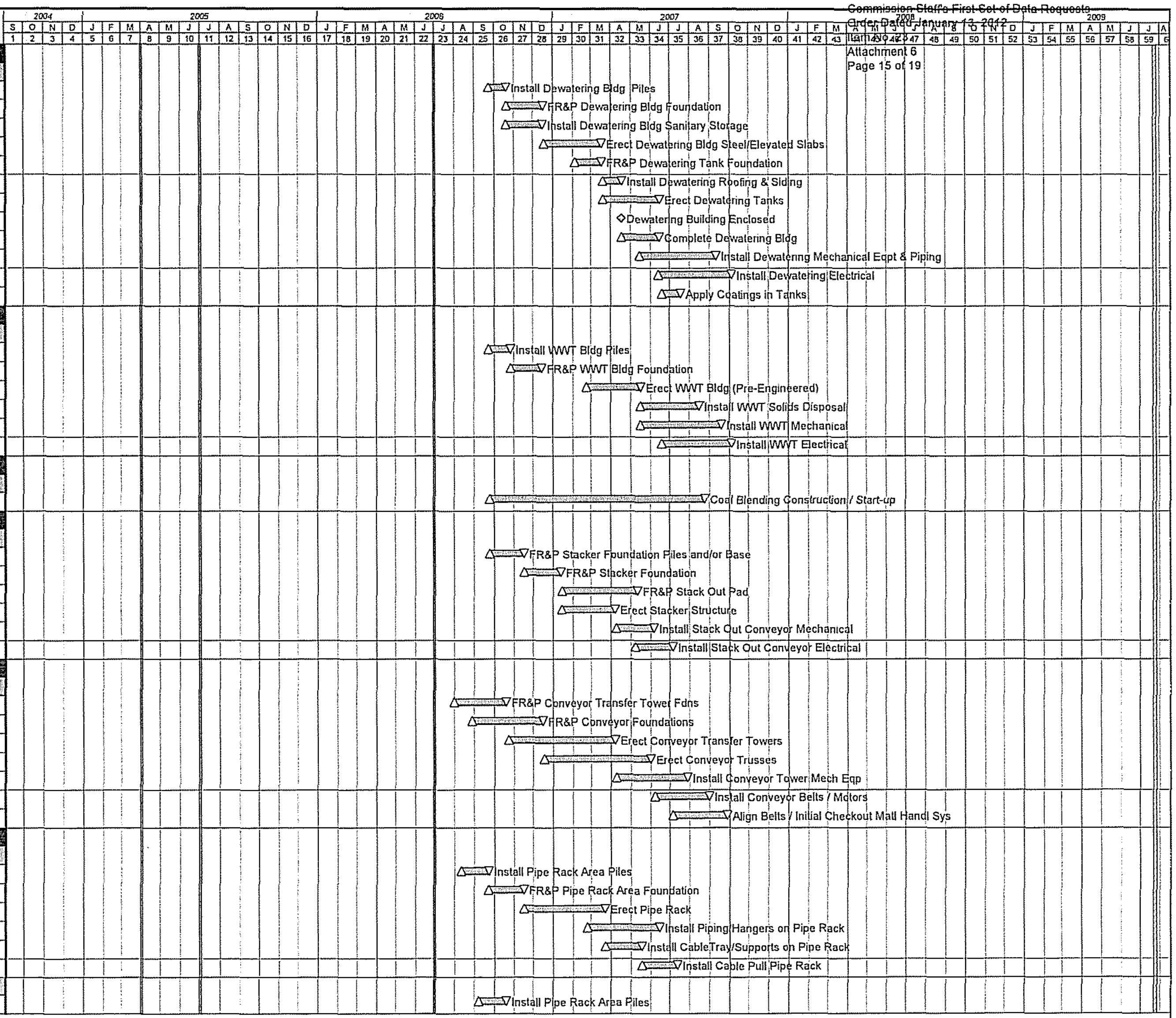
Act. ID	Activity Description	Orig Dur	Start	Finish
SU40 Dewatering Area Construction/Start-up				
C Common				
CN40200	Install Dewatering Bldg Piles	20	22SEP06	19OCT06
CN40300	*FR&P Dewatering Bldg Foundation*	41	20OCT06	15DEC06
CN40410	Install Dewatering Bldg Sanitary Storage	41	20OCT06	15DEC06
CN40420	Erect Dewatering Bldg Steel/Elevated Slabs	65	18DEC06	16MAR07
CN42300	FR&P Dewatering Tank Foundation	30	05FEB07	16MAR07
CN40510	Install Dewatering Roofing & Siding	22	19MAR07	17APR07
CN42510	*Erect Dewatering Tanks*	65	19MAR07	15JUN07
CN40520	Dewatering Building Enclosed	0		17APR07
CN40530	Complete Dewatering Bldg	43	18APR07	15JUN07
CN40600	Install Dewatering Mechanical Eqpt & Piping	86	15MAY07	11SEP07
CN40700	Install Dewatering Electrical	82	13JUN07	04OCT07
CN42520	Apply Coatings in Tanks	22	18JUN07	17JUL07
SU50 Waste Treatment Area Construction/Start-up				
C Common				
CN50200	Install WWT Bldg Piles	25	22SEP06	26OCT06
CN50300	FR&P WWT Bldg Foundation	35	27OCT06	14DEC06
CN50400	Erect WWT Bldg (Pre-Engineered)	60	22FEB07	16MAY07
CN50610	Install WWT Solids Disposal	65	17MAY07	15AUG07
CN50620	Install WWT Mechanical	90	17MAY07	19SEP07
CN50700	Install WWT Electrical	80	18JUN07	05OCT07
SU55 Coal Blending Construction / Start-up				
C Common				
CN55100	Coal Blending Construction / Start-up	240	25SEP06	24AUG07
SU60 Material Handling Area Construction/Start-up				
C Common				
CN60200	FR&P Stacker Foundation Piles and/or Base	39	25SEP06	16NOV06
CN60310	FR&P Stacker Foundation	41	17NOV06	12JAN07
CN60320	FR&P Stack Out Pad	85	15JAN07	11MAY07
CN60400	Erect Stacker Structure	60	15JAN07	06APR07
CN60600	Install Stack Out Conveyor Mechanical	43	09APR07	06JUN07
CN60700	Install Stack Out Conveyor Electrical	42	09MAY07	05JUL07
SU65 Tranfer Towers & Conveyor Construction/Start-up				
C Common				
CN65110	FR&P Conveyor Transfer Tower Fdns	60	31JUL06	20OCT06
CN65210	FR&P Conveyor Foundations	80	28AUG06	15DEC06
CN65120	Erect Conveyor Transfer Towers	120	23OCT06	06APR07
CN65220	Erect Conveyor Trusses	120	18DEC06	01JUN07
CN65130	*Install Conveyor Tower Mech Eqp*	80	09APR07	27JUL07
CN65230	Install Conveyor Belts / Motors	60	08JUN07	30AUG07
CN65410	Align Belts / Initial Checkout Matl Handl Sys	60	06JUL07	27SEP07
SU70 Pipe Rack Construction				
3 Unit 3				
CN70200	Install Pipe Rack Area Piles	30	11AUG06	21SEP06
CN70300	FR&P Pipe Rack Area Foundation	40	22SEP06	16NOV06
CN70400	Erect Pipe Rack	90	17NOV06	22MAR07
CN70600	Install Piping/Hangers on Pipe Rack	80	23FEB07	14JUN07
CN70700	Install CableTray/Supports on Pipe Rack	40	23MAR07	17MAY07
CN70710	Install Cable Pull Pipe Rack	40	18MAY07	12JUL07
1 Unit 1				
C170200	Install Pipe Rack Area Piles	30	08SEP06	19OCT06



Project: SUMH
Layout: LT-E1
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Schedule Summary
Progress Bar
Critical Activity

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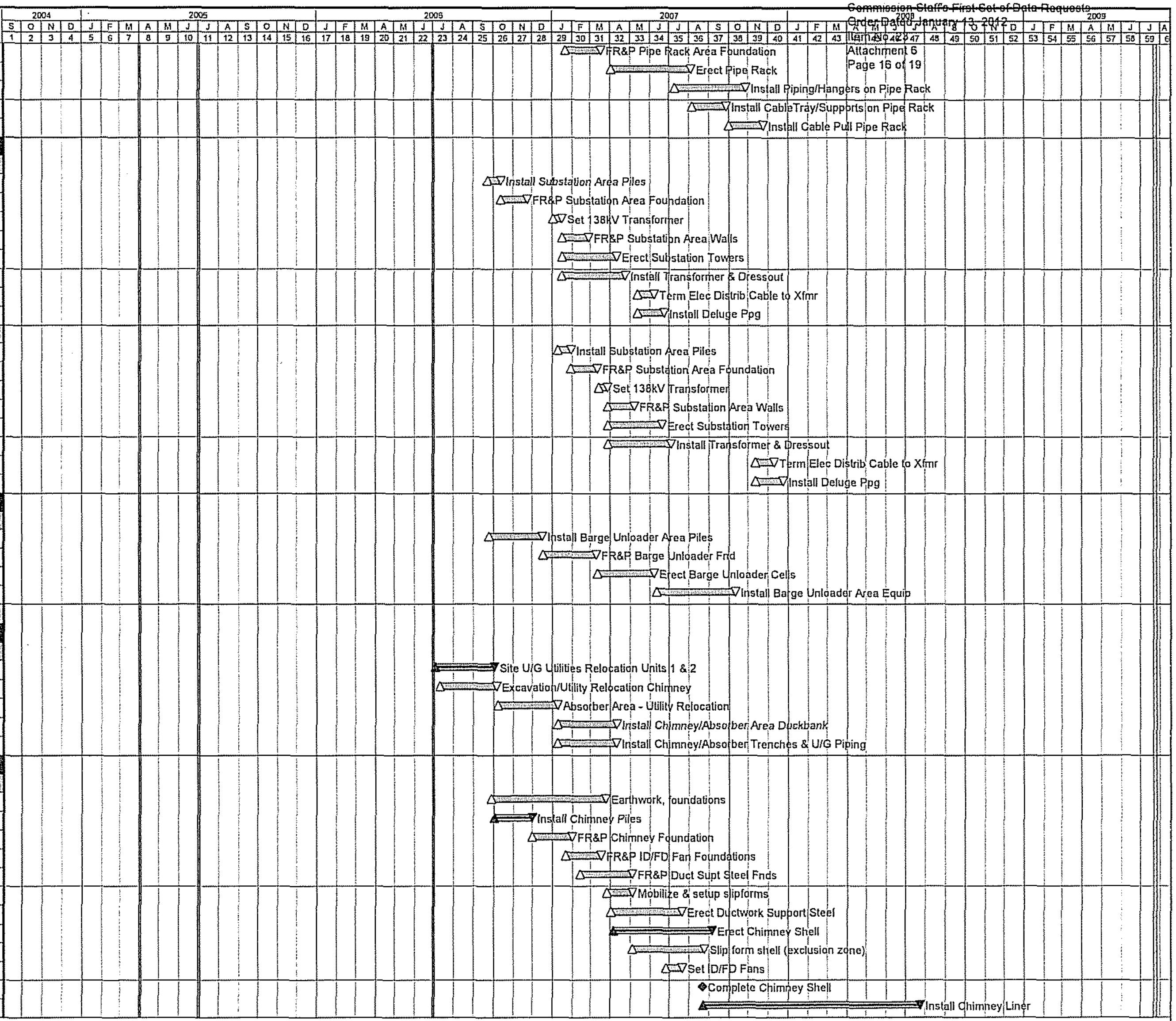
American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	N/A	
01NOV04	Preliminary Issue	DJG	
22NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

Act. ID	Activity Description	Orig Dur	Start	Finish
C170300	FR&P Pipe Rack Area Foundation	40	22JAN07	16MAR07
C170400	Erect Pipe Rack	90	02APR07	03AUG07
C170600	Install Piping/Hangers on Pipe Rack	80	09JUL07	26OCT07
C170700	Install CableTray/Supports on Pipe Rack	40	06AUG07	28SEP07
C170710	Install Cable Pull Pipe Rack	40	01OCT07	23NOV07
SU80 Substation Area Construction/Start-up				
3 Unit 3				
CN80200	Install Substation Area Piles	15	22SEP06	12OCT06
CN80300	FR&P Substation Area Foundation	30	13OCT06	23NOV06
CN80400	Set 138kV Transformer	10	02JAN07	15JAN07
CN80500	FR&P Substation Area Walls	30	16JAN07	26FEB07
CN80600	Erect Substation Towers	60	16JAN07	09APR07
CN80710	Install Transformer & Dressout	70	16JAN07	23APR07
CN80720	Term Elec Distrib Cable to Xfmr	20	14MAY07	08JUN07
CN80730	Install Deluge Ppg	30	14MAY07	22JUN07
1 Unit 1				
C180200	Install Substation Area Piles	15	09JAN07	29JAN07
C180300	FR&P Substation Area Foundation	30	30JAN07	12MAR07
C180400	Set 138kV Transformer	10	14MAR07	27MAR07
C180500	FR&P Substation Area Walls	30	28MAR07	08MAY07
C180600	Erect Substation Towers	60	28MAR07	19JUN07
C180710	Install Transformer & Dressout	70	28MAR07	03JUL07
C180720	Term Elec Distrib Cable to Xfmr	20	13NOV07	10DEC07
C180730	Install Deluge Ppg	30	13NOV07	24DEC07
SU85-Barge Unloader Area Construction/Start-up				
C Common				
CN85200	*Install Barge Unloader Area Piles*	60	25SEP06	15DEC06
CN85300	FR&P Barge Unloader Fnd	60	18DEC06	09MAR07
CN85500	Erect Barge Unloader Cells	65	12MAR07	08JUN07
CN85700	Install Barge Unloader Area Equip	90	11JUN07	12OCT07
C1 CONSTRUCTION UNIT 1				
SU01 Initial / Final Site Prep				
1 Unit 1				
C110000	Site U/G Utilities Relocation Units 1 & 2	66	03JUL06*	02OCT06
C110110	Excavation/Utility Relocation Chimney	65	10JUL06*	06OCT06
C115100	Absorber Area - Utility Relocation	66	09OCT06	08JAN07
C115110	Install Chimney/Absorber Area Duckbank	66	09JAN07	10APR07
C115120	Install Chimney/Absorber Trenches & U/G Piping	66	09JAN07	10APR07
SU10 Flue Gas Area / Ductwork Construction/Start-up				
1 Unit 1				
STK2049	Earthwork, foundations	127	28SEP06	23MAR07
C110210	Install Chimney Piles	43	03OCT06*	30NOV06
C110300	FR&P Chimney Foundation	43	01DEC06	30JAN07
C112300	FR&P ID/FD Fan Foundations	40	22JAN07	16MAR07
C114300	FR&P Duct Supt Steel Fnds	60	12FEB07	04MAY07
STK2050	Mobilize & setup slipforms	29	26MAR07	03MAY07
C114400	Erect Ductwork Support Steel	80	02APR07	20JUL07
C110400	Erect Chimney Shell	110	05APR07	05SEP07
STK2060	Slip form shell (exclusion zone)	81	04MAY07	24AUG07
C112400	Set ID/FD Fans	20	25JUN07	20JUL07
C110410	*Complete Chimney Shell*	0		20AUG07
C110510	Install Chimney Liner	240	23AUG07	23JUL08



Project: SUMH
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Schedule Summary
Progress Bar
Critical Activity

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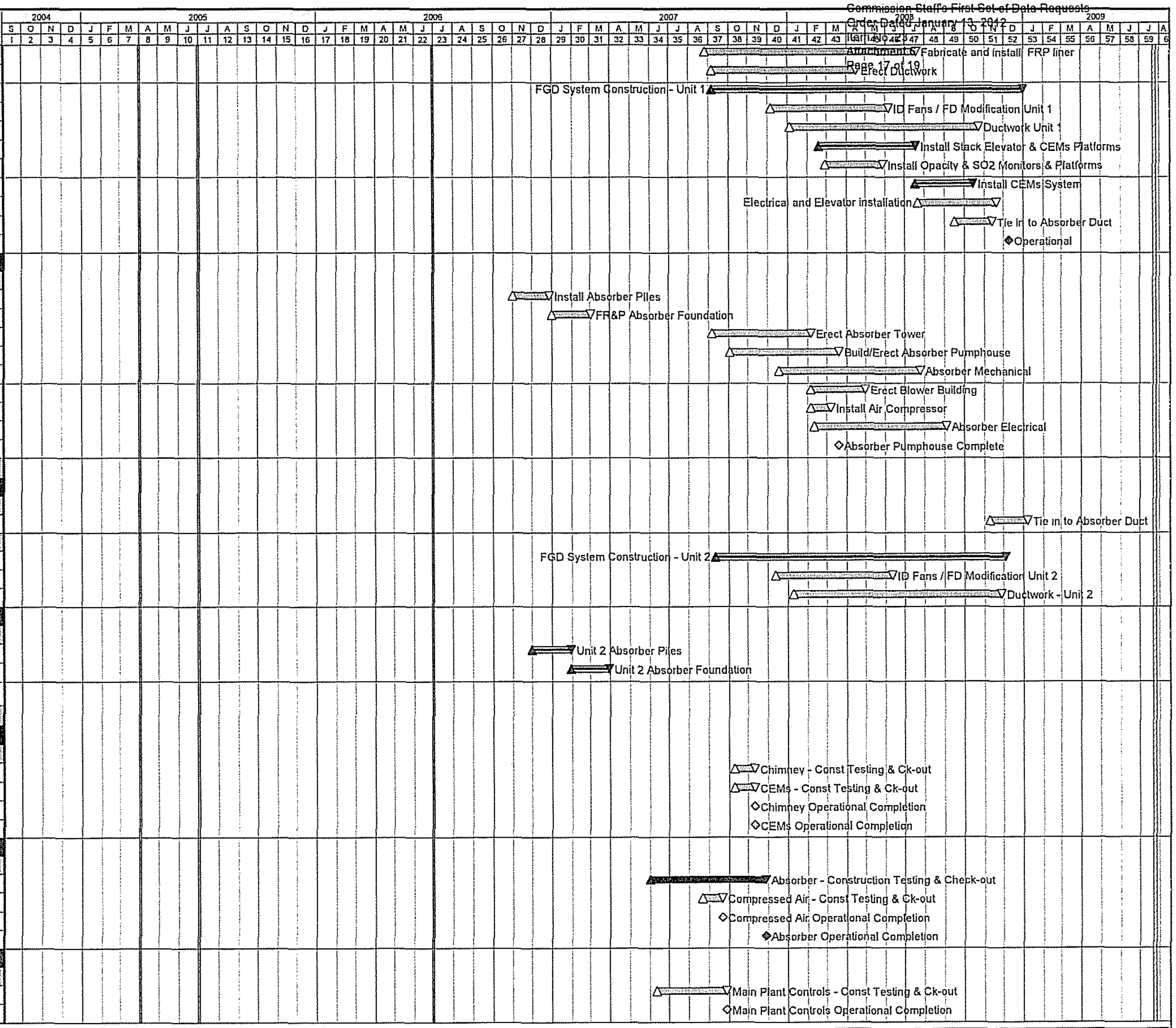
American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
20OCT04	Initial Draft	N/A	
11NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

Act. ID	Activity Description	Orig Dur	Start	Finish
STK2070	Fabricate and install FRP liner	235	27AUG07	18JUL08
C114610	Erect Ductwork	160	06SEP07	16APR08
C120010	FGD System Construction - Unit 1	345	06SEP07	31DEC08
C120020	ID Fans / FD Modification Unit 1	130	07DEC07	05JUN08
C120030	Ductwork Unit 1	210	04JAN08	23OCT08
C110520	Install Stack Elevator & CEMs Platforms	107	19FEB08	16JUL08
C110600	Install Opacity & SO2 Monitors & Platforms	64	29FEB08	28MAY08
C111600	Install CEMs System	64	17JUL08	14OCT08
STK2080	Electrical and Elevator installation	88	21JUL08	19NOV08
STK2090	Tie in to Absorber Duct	58	16SEP08	12NOV08
STK2100	Operational	0	10DEC08*	
SU15-Absorber Building Area Construction/Start-up				
1 Unit 1				
C115220	Install Absorber Piles	42	01NOV06	28DEC06
C115300	FR&P Absorber Foundation	44	01JAN07	01MAR07
C115400	Erect Absorber Tower	110	06SEP07*	06FEB08
C115500	Build/Erect Absorber Pumphouse	120	04OCT07	19MAR08
C115600	Absorber Mechanical	156	19DEC07	23JUL08
C115520	Erect Blower Building	60	07FEB08	30APR08
C115610	Install Air Compressor	22	07FEB08	07MAR08
C115700	Absorber Electrical	148	11FEB08	03SEP08
C115510	Absorber Pumphouse Complete	0		19MAR08
C2 CONSTRUCTION UNIT 2				
SU10 Flue Gas Area / Ductwork Construction/Start-up				
1 Unit 1				
STK2290	Tie in to Absorber Duct	58	10NOV08	06JAN09
2 Unit 2				
C220010	FGD System Construction - Unit 2	322*	12SEP07	04DEC08
C220020	ID Fans / FD Modification Unit 2	130	13DEC07	11JUN08
C220030	Ductwork - Unit 2	231	10JAN08	27NOV08
SU15-Absorber Building Area Construction/Start-up				
2 Unit 2				
C230010	Unit 2 Absorber Piles	43	30NOV06	29JAN07
C230020	Unit 2 Absorber Foundation	43	30JAN07	29MAR07
04 STARTUP & COMMISSIONING				
S3 PRE-COMMISSIONING / START-UP UNIT 3				
SU10 Flue Gas Area / Ductwork Construction/Start-up				
3 Unit 3				
SU10910	Chimney - Const Testing & Ck-out	22	11OCT07	09NOV07
SU11910	CEMs - Const Testing & Ck-out	22	11OCT07	09NOV07
SU10920	Chimney Operational Completion	0		09NOV07
SU11920	CEMs Operational Completion	0		09NOV07
SU15 Absorber Building Area Construction/Start-up				
3 Unit 3				
SU15910	Absorber - Construction Testing & Check-out	178	02JUN07	26NOV07
SU15930	Compressed Air - Const Testing & Ck-out	23	21AUG07	20SEP07
SU15940	Compressed Air Operational Completion	0		20SEP07
SU15920	Absorber Operational Completion	0		26NOV07
SU25 Limestone Prep Area Construction/Start-up				
C Common				
SU25810	Main Plant Controls - Const Testing & Ck-out	80	11JUN07	28SEP07
SU25820	Main Plant Controls Operational Completion	0		28SEP07



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American Electric Power
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Sargent & Lundy LLC

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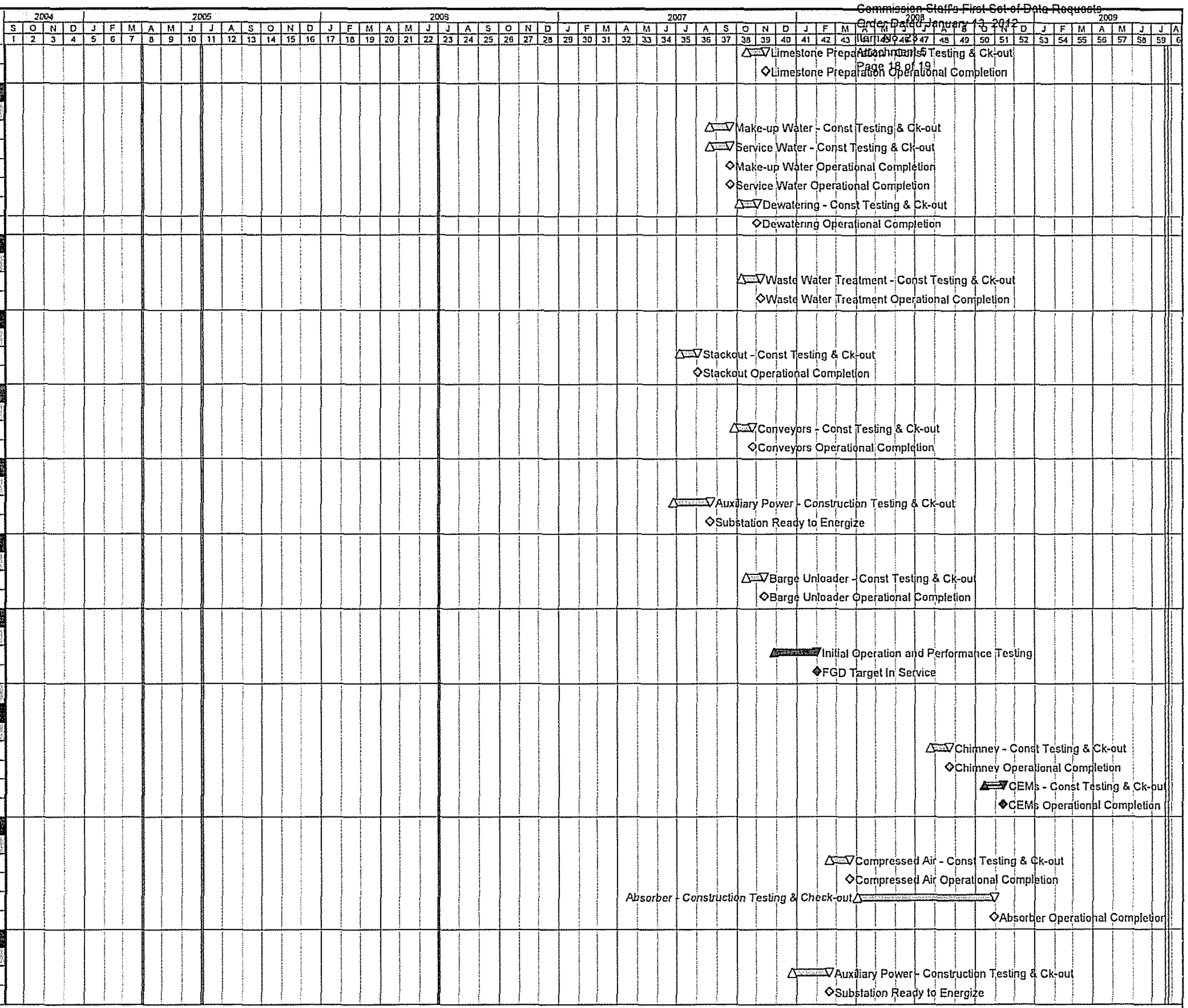
22OCT04	Initial Draft	NJA	
01NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

Act. ID	Activity Description	Orig Dur	Start	Finish
SU25910	Limestone Preparation - Const Testing & Ck-out	21	17OCT07	14NOV07
SU25920	Limestone Preparation Operational Completion	0		14NOV07
SU40 Dewatering Area Construction/Start-up				
C Common				
SU25950	Make-up Water - Const Testing & Ck-out	23	21AUG07	20SEP07
SU25970	Service Water - Const Testing & Ck-out	23	21AUG07	20SEP07
SU25960	Make-up Water Operational Completion	0		20SEP07
SU25980	Service Water Operational Completion	0		20SEP07
SU40910	*Dewatering - Const Testing & Ck-out*	20	05OCT07	01NOV07
SU40920	Dewatering Operational Completion	0		01NOV07
SU50 Waste Treatment Area Construction/Start-up				
C Common				
SU50910	Waste Water Treatment - Const Testing & Ck-out	22	08OCT07	06NOV07
SU50920	Waste Water Treatment Operational Completion	0		06NOV07
SU60 Material Handling Area Construction/Start-up				
C Common				
SU60910	Stackout - Const Testing & Ck-out	20	06JUL07	02AUG07
SU60920	Stackout Operational Completion	0		02AUG07
SU65 Tranfer Towers & Conveyor Construction/Start-up				
C Common				
SU65910	Conveyors - Const Testing & Ck-out	20	28SEP07	25OCT07
SU65920	Conveyors Operational Completion	0		25OCT07
SU80 Substation Area Construction/Start-up				
3 Unit 3				
SU80910	Auxiliary Power - Construction Testing & Ck-out	41	25JUN07	20AUG07
SU80920	Substation Ready to Energize	0		20AUG07
SU85 Barge Unloader Area Construction/Start-up				
C Common				
SU85910	Barge Unloader - Const Testing & Ck-out	21	15OCT07	12NOV07
SU85920	*Barge Unloader Operational Completion*	0		12NOV07
SU98 System Start-up, Testing & Checkout				
3 Unit 3				
SU98910	Initial Operation and Performance Testing	66	27NOV07	31JAN08
SU98920	FGD Target In Service	0		31JAN08
S1 PRE-COMMISSIONING / START-UP UNIT 1				
SU10 Flue Gas Area / Ductwork Construction/Start-up				
1 Unit 1				
S110910	Chimney - Const Testing & Ck-out	22	24JUL08	22AUG08
S110920	Chimney Operational Completion	0		22AUG08
S111910	CEMs - Const Testing & Ck-out	22	15OCT08	13NOV08
S111920	CEMs Operational Completion	0		13NOV08
SU15 Absorber Building Area Construction/Start-up				
1 Unit 1				
S115930	Compressed Air - Const Testing & Ck-out	23	20FEB08	21MAR08
S115940	Compressed Air Operational Completion	0		21MAR08
S115910	Absorber - Construction Testing & Check-out	210	03APR08	29OCT08
S115920	Absorber Operational Completion	0		29OCT08
SU60 Substation Area Construction/Start-up				
1 Unit 1				
S180910	Auxiliary Power - Construction Testing & Ck-out	41	25DEC07	19FEB08
S180920	Substation Ready to Energize	0		19FEB08



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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	TUA	
01NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

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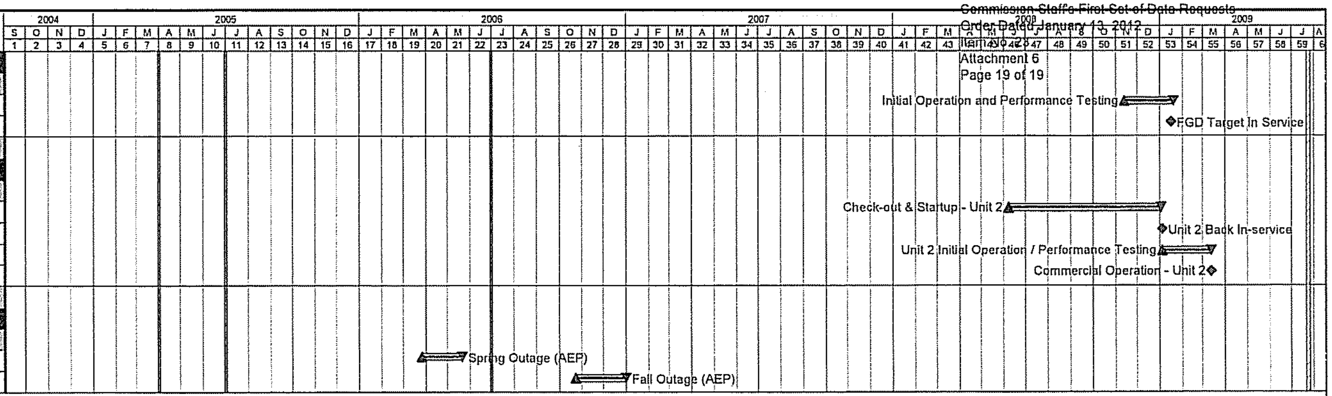
Act. ID	Activity Description	Orig Dur	Start	Finish
SU98 System Start-up, Testing & Checkout				
1 Unit 1				
S198910	Initial Operation and Performance Testing	66	14NOV08	18JAN09
S198920	FGD Target In Service	0		16JAN09
S2 PRE-COMMISSIONING / START-UP UNIT 2				
SU98 System Start-up, Testing & Checkout				
2 Unit 2				
S290100	Check-out & Startup - Unit 2	210	07JUN08*	02JAN09
S290110	Unit 2 Back In-service	0		04JAN09
S290120	Unit 2 Initial Operation / Performance Testing	66	05JAN09	11MAR09
S290130	Commercial Operation - Unit 2	0		11MAR09
SU PRE-COMMISSIONING / START-UP				
SU98 System Start-up, Testing & Checkout				
C Common				
SUCO9010	Spring Outage (AEP)	54	28MAR06*	20MAY06
SUCO9120	Fall Outage (AEP)	69	24OCT06*	31DEC06



Project: SUMH
Layout: LT-E1
Run Date: 30DEC04 09:29

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Schedule Summary
Progress Bar
Critical Activity

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American Electric Power
AMOS FGD Retrofit Projectect
Level I Project Schedule

Sargent & Lundy LLC

Date	Revision	Checked	Approved
22OCT04	Initial Draft	N/A	
01NOV04	Preliminary Issue	DJG	
30NOV04	Preliminary Project Schedule	MSS	
30DEC04	Preliminary Project Schedule	MSS	

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
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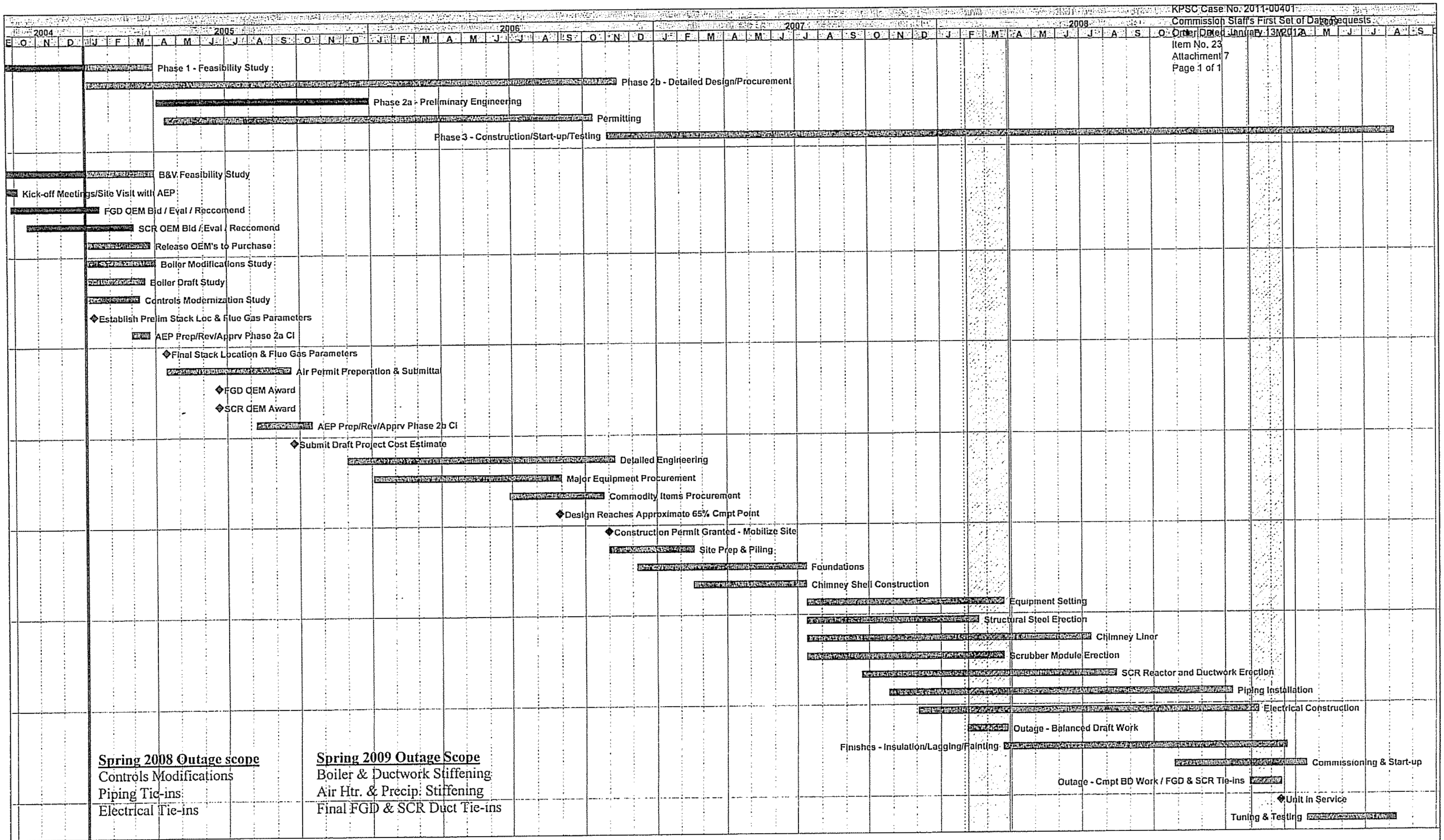

Spring 2008 Outage scope
Controls Modifications
Piping Tie-ins
Electrical Tie-ins

Spring 2009 Outage Scope
Boiler & Ductwork Stiffening
Air Htr. & Precip. Stiffening
Final FGD & SCR Duct Tie-ins

Start Date	22SEP04
Finish Date	15JAN10
Data Date	01JAN05
Run Date	03JAN05 17:08

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▨ Early Bar
▬ Progress Bar
▬ Critical Activity

AEPM

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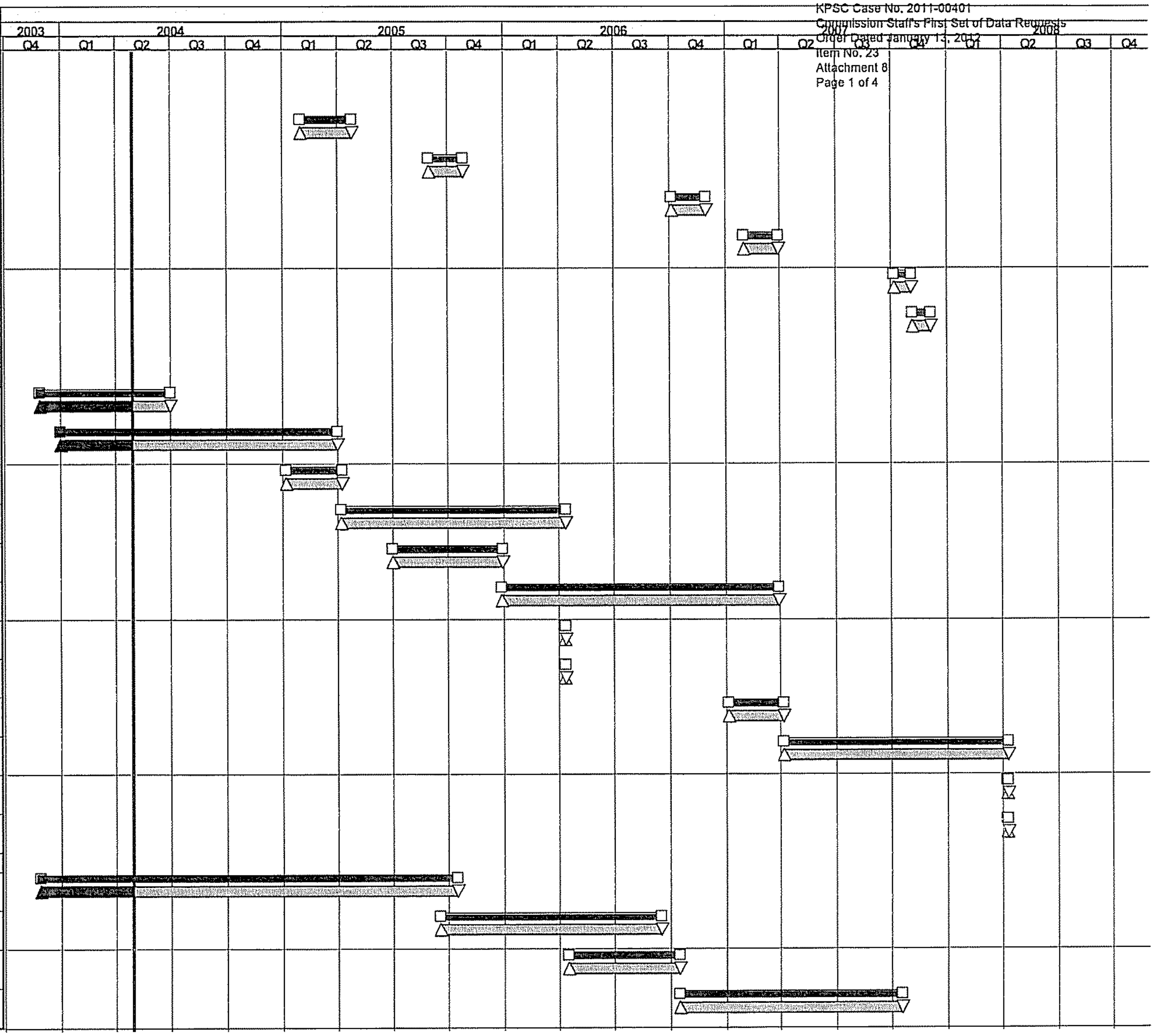
Black & Veatch Corporation
AEP Conesville - Master Project
Summary Level 1 Execution Plan

Date	Revision	Checked	Approved

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Mitchell Plant					
Scheduled Outages					
Level 2 Subset Activities					
ML_9057	2005 GBIR Unit 2	01FEB05*	26APR05	01FEB05*	26APR05
ML_9006	2005 GBIR Unit 1	30AUG05*	25OCT05	30AUG05*	25OCT05
ML_9059	SCR TIE-IN U2	04OCT06*	29NOV06	04OCT06*	29NOV06
ML_9058	SCR TIE-IN U1	01FEB07*	29MAR07	01FEB07*	29MAR07
ML_9061	FGD TIE-IN U2	05OCT07*	03NOV07	05OCT07*	03NOV07
ML_9060	FGD TIE-IN U1	06NOV07*	04DEC07	06NOV07*	04DEC07
FGD Landfill					
CONSOL Option					
MLC0100	CONSOL PH 1 Concept	28NOV03A	30JUN04	28NOV03A	30JUN04
MLC0200	Gypsum Use Applications - 1050'	01JAN04A	01APR05	01JAN04A	01APR05
MLC0300	Prepare & Submit Application for Gypsum Use	07JAN05	08APR05	07JAN05	08APR05
MLC0400	Agency Review	08APR05	11APR06	08APR05	11APR06
MLC0900	CONSOL PH2 Concept	01JUL05	28DEC05	01JUL05	28DEC05
MLC1000	Gypsum Use Applications - 1180'	28DEC05	29MAR07	28DEC05	29MAR07
MLC0500	Receive Permit To 1050'	11APR06	11APR06	11APR06	11APR06
MLC0800	Start Place Gypsum	11APR06	11APR06	11APR06	11APR06
MLC1100	Prepare & Submit Application for Gypsum Use	05JAN07	05APR07	05JAN07	05APR07
MLC1200	Agency Review	05APR07	08APR08	05APR07	08APR08
MLC1300	Receive Permit To 1180'	08APR08	08APR08	08APR08	08APR08
MLC1500	Continue Place Gypsum	08APR08	08APR08	08APR08	08APR08
New Landfill					
MLN0100	Initiate Siting Study & Secure Land	28NOV03A	14OCT05	28NOV03A	14OCT05
MLN0200	Design Landfill	16SEP05	15SEP06	16SEP05	15SEP06
MLN0300	Prepare & Submit Application for Landfill Permit	17APR06	16OCT06	17APR06	16OCT06
MLN0400	Agency Review	16OCT06	16OCT07	16OCT06	16OCT07



Start Date	06JUN03
Finish Date	16OCT10
Data Date	29APR04
Run Date	30APR04 14:57

Target Bar
Early Bar
Progress Bar

FGD9

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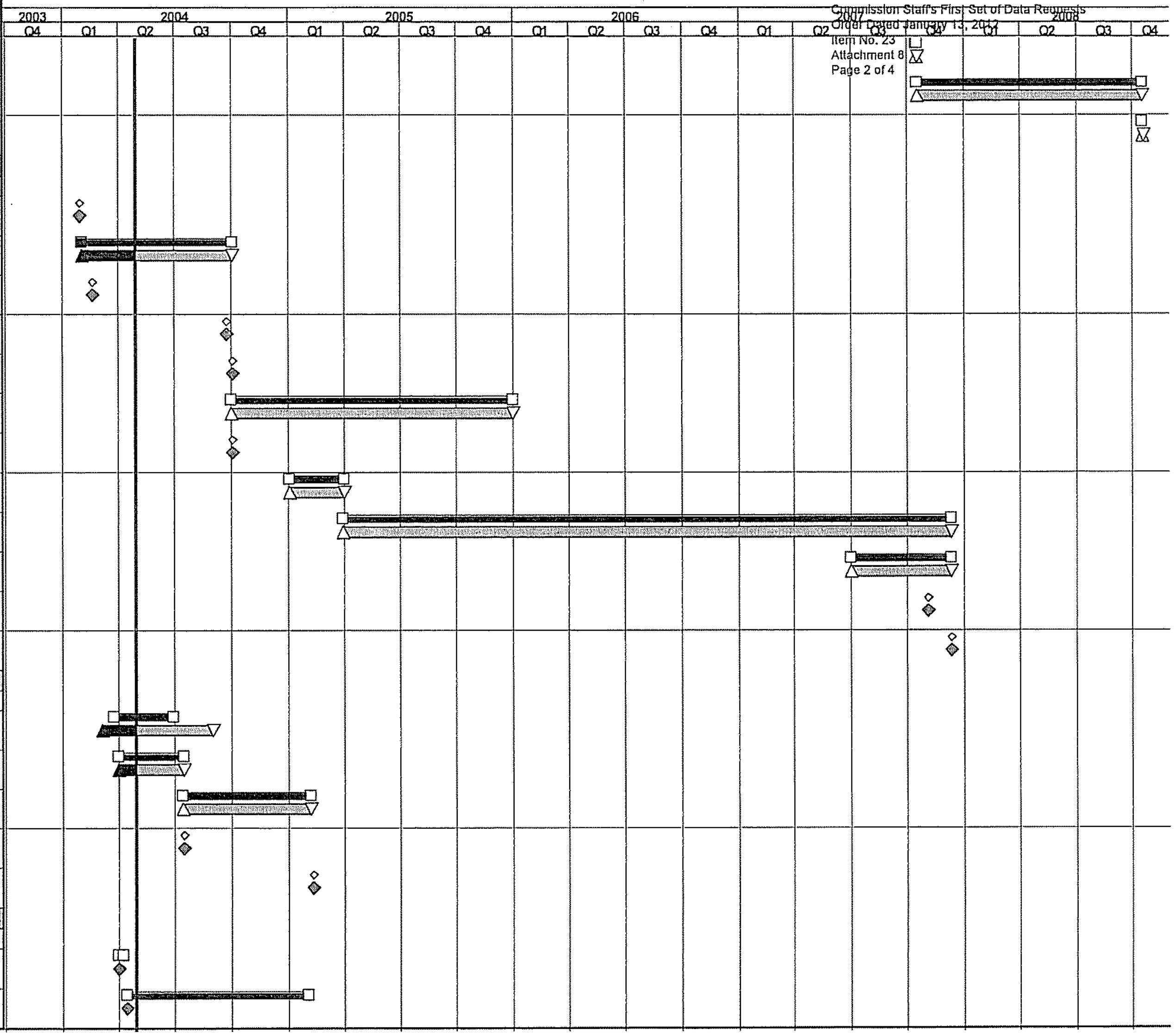
AEP
Environmental Projects Summary
Mitchell

AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
MLN0500	Receive Landfill Permit	16OCT07	16OCT07	16OCT07	16OCT07
MLN0600	Construct Landfill	17OCT07	17OCT08	17OCT07	17OCT08
MLN0800	Place Waste	18OCT08	18OCT08	17OCT08	17OCT08
Flue Gas Desulfurization					
Level 2 Subset Activities					
ML_9019	Phase 2 CI Approval		28JAN04A		28JAN04A
ML_9023	Phase 2 FGD E&D	02FEB04A	01OCT04	02FEB04A	01OCT04
ML_9021	Selection of OEM		18FEB04A		18FEB04A
ML_9020	Phase 3 CI Approval		22SEP04*		22SEP04*
ML_9022	Selection of FGD Constructor		01OCT04*		01OCT04*
ML_9024	Phase 3 FGD E&D	01OCT04*	30DEC05	01OCT04*	30DEC05
ML_9029	Selection of Construction Manager		01OCT04*		01OCT04*
ML_9027	Relocations	03JAN05*	31MAR05	03JAN05*	31MAR05
ML_9025	FGD Construction	31MAR05*	10DEC07	31MAR05*	10DEC07
ML_9026	FGD Commissioning	02JUL07*	10DEC07	02JUL07*	10DEC07
ML_9031	Initial FGD Operation Unit 2		02NOV07*		02NOV07*
ML_9028	Initial FGD Operation Unit 1		10DEC07*		10DEC07*
Air Permitting					
Level 2 Subset Activities					
ML_9014	Perform Ambient Air Quality Modeling	05MAR04A	30AUG04	24MAR04*	28JUN04
ML_9015	Prepare Air Permit Application	31MAR04A	14JUL04	31MAR04*	14JUL04
ML_9016	Agency Review	14JUL04*	06FEB05	14JUL04*	06FEB05
ML_9018	Submit Air Permit Application		14JUL04*		14JUL04*
ML_9017	Receive PTI & Commence Major Construction		09FEB05*		09FEB05*
Balanced Draft					
Level 2 Subset Activities					
ML_9041	Release A/E to Commence Balanced Draft E&D	31MAR04A		31MAR04*	07APR04
ML_9042	AE / OEM Detailed Balanced Draft E&D	15APR04A		15APR04*	01FEB05



Start Date	06JUN03
Finish Date	16OCT10
Data Date	29APR04
Run Date	30APR04 14:57

▭ Target Bar
▽ Early Bar
▬ Progress Bar

FGD9

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AEP
Environmental Projects Summary
Mitchell

AMERICAN ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

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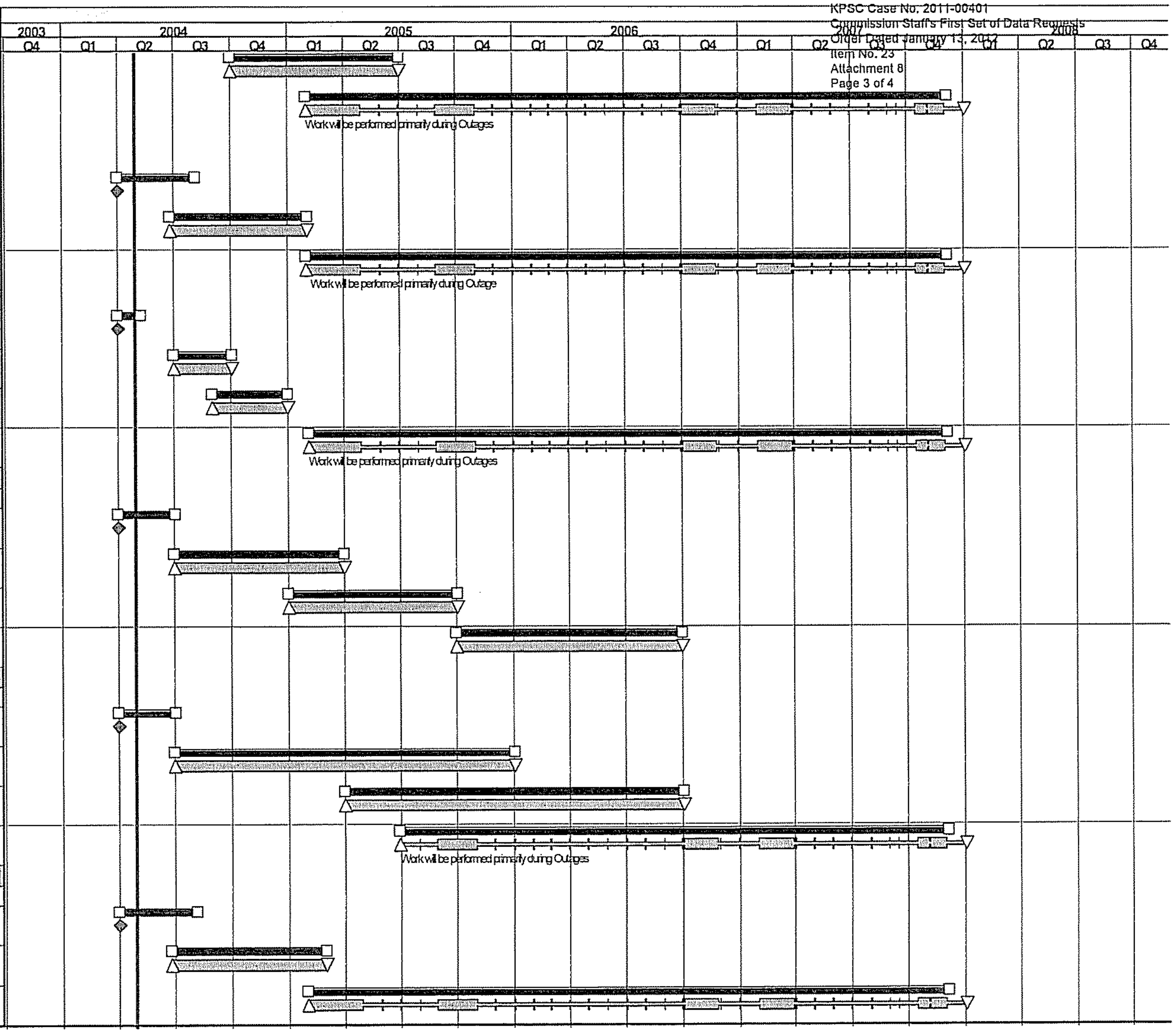
Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
ML_9044	Procure Balanced Draft Materials	01OCT04*	01JUL05	01OCT04*	01JUL05
ML_9043	Perform Balanced Draft Modifications	01FEB05*	01JAN08	01FEB05*	04DEC07
Boiler Modifications					
Slag Control Devices					
ML_9030	Release A/E for Slag Control Device E&D	31MAR04A		31MAR04*	05AUG04
ML_9032	Procure Slag Control Materials	24JUN04*	01FEB05	24JUN04*	01FEB05
ML_9035	Install Slag Control Devices	01FEB05*	01JAN08	01FEB05*	04DEC07
Superheat Slag Monitoring System					
ML_9033	Release A/E for Slag Monitoring E&D for CI	31MAR04A		31MAR04*	08MAY04
ML_9034	Perform Detailed Slag Monitoring E&D	01JUL04*	01OCT04	01JUL04*	01OCT04
ML_9036	Procure Slag Monitoring Materials	01SEP04*	31DEC04	01SEP04*	31DEC04
ML_9065	Install Slag Monitoring Devices	04FEB05*	01JAN08	04FEB05*	04DEC07
Coal Blending					
Level 2 Subset Activities					
ML_9049	Release A/E to Evaluate Requirements	31MAR04A		31MAR04*	01JUL04
ML_9050	Perform Detailed Coal Blending E&D	01JUL04*	01APR05	01JUL04*	01APR05
ML_9051	Procure Coal Blending Materials	01JAN05*	01OCT05	01JAN05*	01OCT05
ML_9052	Install Coal Blending Equipment	01OCT05*	01OCT06	01OCT05*	01OCT06
Control Modernization					
Level 2 Subset Activities					
ML_9045	Release A/E to E/D Control System Modernization	31MAR04A		31MAR04*	01JUL04
ML_9046	Perform Detailed Control Modernization E&D	01JUL04*	01JAN06	01JUL04*	01JAN06
ML_9047	Procure Control System Equipment	01APR05*	02OCT06	01APR05*	02OCT06
ML_9048	Install Control Modernization Modifications	30JUN05*	01JAN08	30JUN05*	04DEC07
Furnace Arch					
Level 2 Subset Activities					
ML_9066	Engineering & Design	01APR04A		01APR04*	05AUG04
ML_9067	Procurement	24JUN04*	01MAR05	24JUN04*	01MAR05
ML_9068	Installation (Outage Driven)	01FEB05*	01JAN08	01FEB05*	04DEC07



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Sheet 3A of 4B

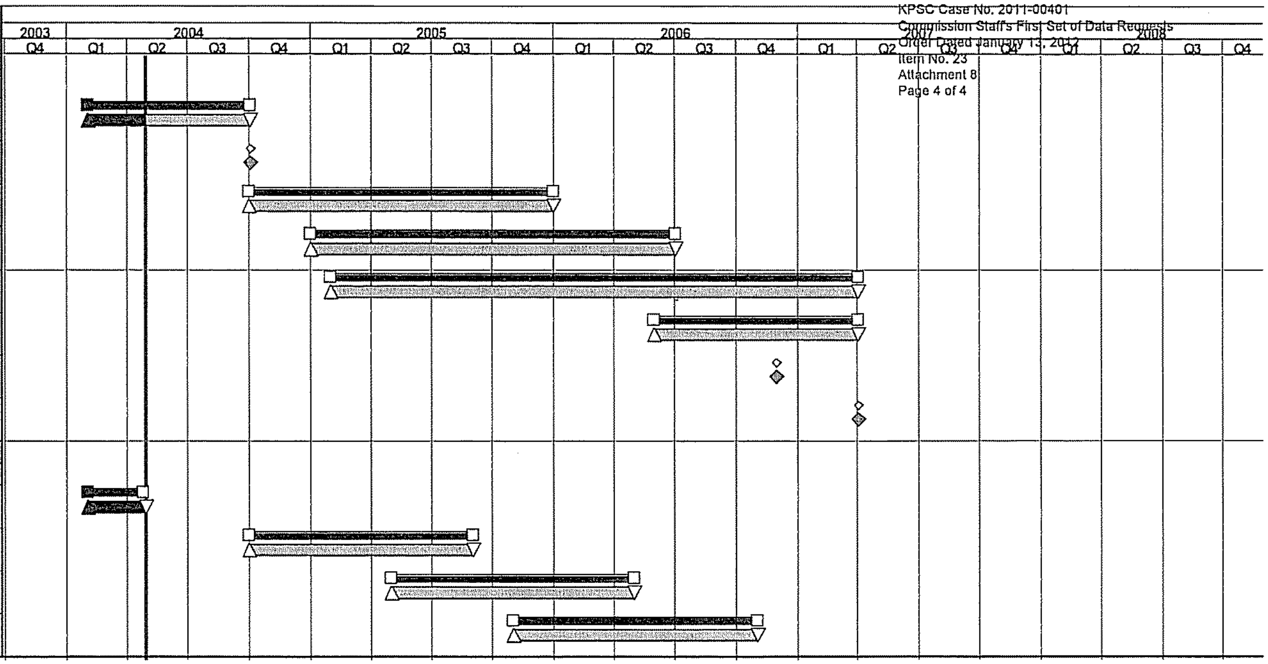
AEP
Environmental Projects Summary
Mitchell

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Selective Catalytic Reduction					
Level 2 Subset Activities					
ML_9069	SCR Phase II E&D	02FEB04A	01OCT04	02FEB04A	01OCT04
ML_9037	Selection of Construction Manager		01OCT04*		01OCT04*
ML_9070	SCR Phase III E&D	01OCT04*	31DEC05	01OCT04*	31DEC05
ML_9071	SCR Procurement	01JAN05*	01JUL06	01JAN05*	01JUL06
ML_9038	SCR Construction	01FEB05*	02APR07	01FEB05*	02APR07
ML_9039	SCR Commissioning	01JUN06*	02APR07	01JUN06*	02APR07
ML_9062	Initial SCR Operation Unit 2		29NOV06*		29NOV06*
ML_9040	Initial SCR Operation Unit 1		02APR07*		02APR07*
SO3 Mitigation					
Level 2 Subset Activities					
ML_9053	Release A/E for SO3 Mitigation E&D for CI	02FEB04A		02FEB04A	24APR04
ML_9054	SO3 Mitigation Engineering and Design	01OCT04*	01SEP05	01OCT04*	01SEP05
ML_9056	Procure SO3 Mitigaton Equipment	02MAY05*	30APR06	02MAY05*	30APR06
ML_9055	Install SO3 Mitigation System	01NOV05*	01NOV06	01NOV05*	01NOV06



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Sheet 4A of 4B

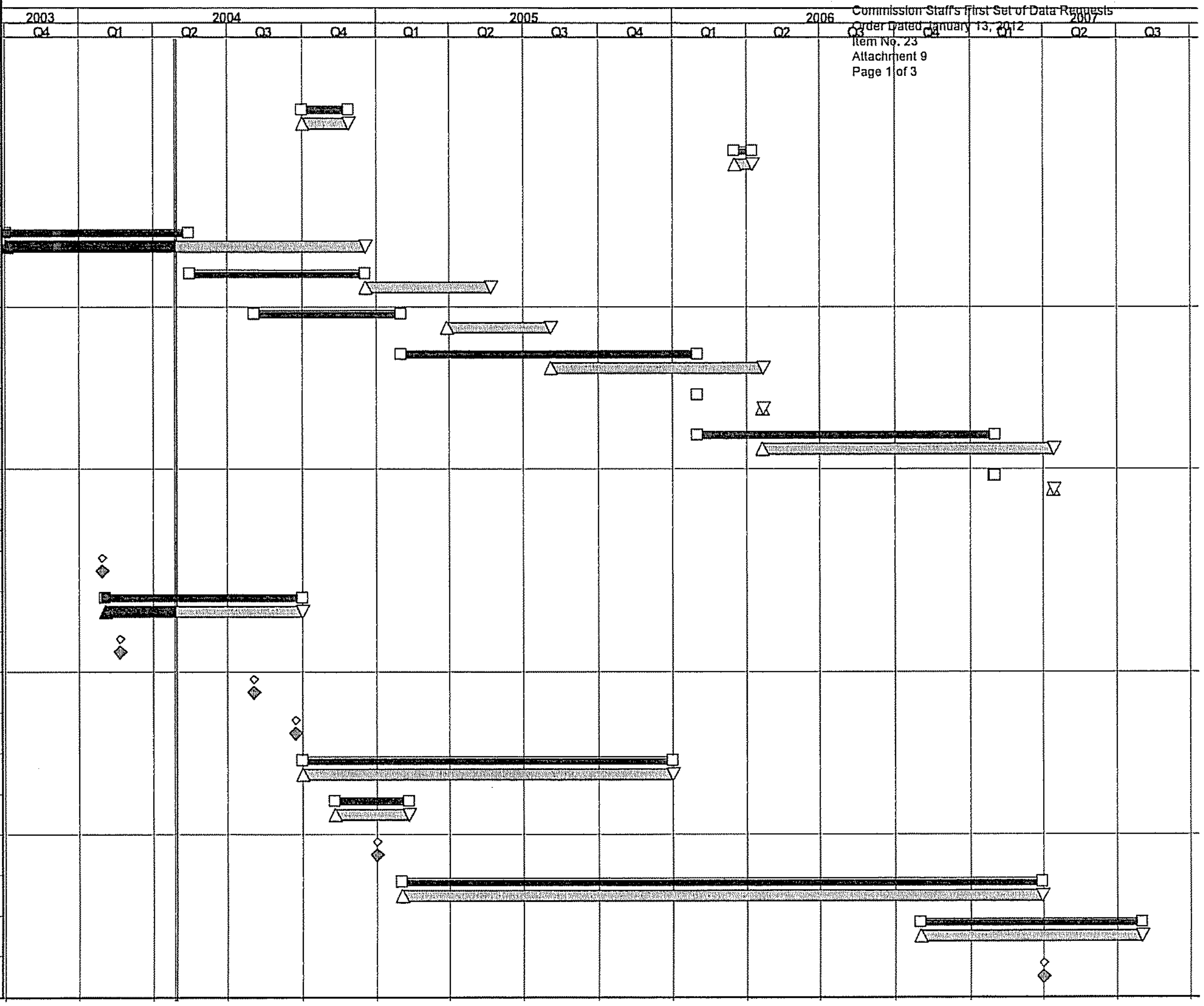
AEP
Environmental Projects Summary
Mitchell

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Mountaineer Plant					
Scheduled Outages					
Level 2 Subset Activities					
MT_0100	2004 GBIR	02OCT04*	27NOV04	02OCT04*	27NOV04
MT_0200	2006 Touch-Up Outage	18MAR06*	08APR06	18MAR06*	08APR06
FGD Landfill					
New Landfill					
MTN0100	Gypsum Concept Study	03OCT03A	17DEC04	03OCT03A	14MAY04
MTN0200	Design Landfill Modifications	18DEC04	21MAY05	17MAY04	17DEC04
MTN0300	Prepare & Submit App. for Landfill Mod. Permit	28MAR05	03AUG05	04AUG04	31JAN05
MTN0400	Agency Review	03AUG05	21APR06	31JAN05	31JAN06
MTN0500	Receive Landfill Mod. Permit	21APR06	21APR06	31JAN06	31JAN06
MTN0600	Construct Landfill Modification	21APR06	13APR07	31JAN06	31JAN07
MTN0800	Place Waste	13APR07	13APR07	31JAN07	31JAN07
Flue Gas Desulfurization					
Level 2 Subset Activities					
MT_2902	Phase 2 CI Approval		28JAN04A		28JAN04A
MT_3000	Phase 2 FGD E&D	02FEB04A	01OCT04	02FEB04A	01OCT04
MT_2905	Selection of OEM		18FEB04A		18FEB04A
MT_3006	Selection of Construction Manager		01AUG04*		01AUG04*
MT_2903	Phase 3 CI Approval		22SEP04*		22SEP04*
MT_3001	Phase 3 FGD E&D	01OCT04*	30DEC05	01OCT04*	30DEC05
MT_3004	Relocations	11NOV04*	09FEB05	11NOV04*	09FEB05
MT_2906	Selection of FGD Constructor		31DEC04*		31DEC04*
MT_3002	FGD Construction	01FEB05*	30MAR07	01FEB05*	30MAR07
MT_3003	FGD Commissioning	01NOV06*	31JUL07	01NOV06*	31JUL07
MT_3005	Initial FGD Operation		01APR07*		01APR07*



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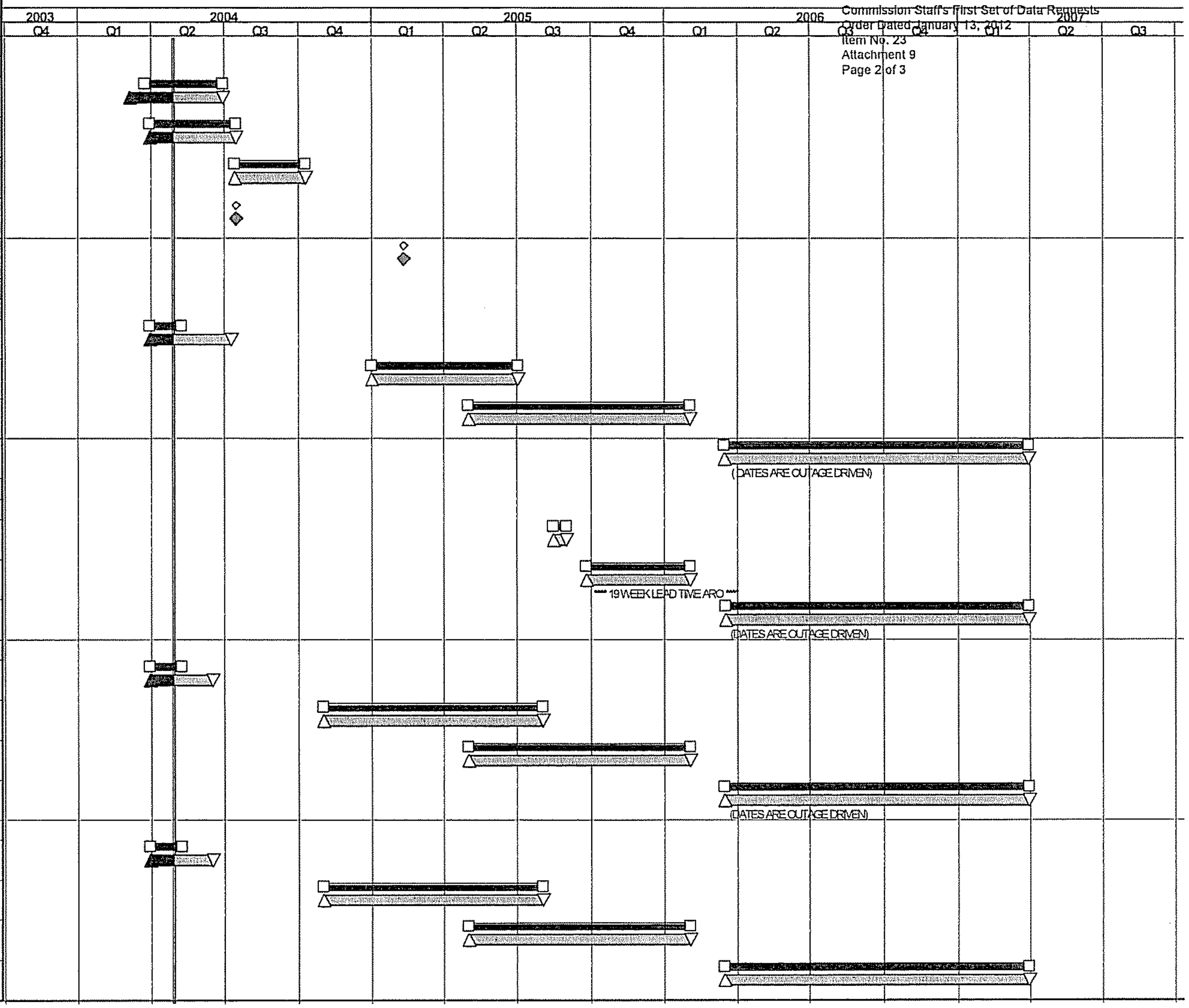
AEP
Environmental Projects Summary
Mountaineer

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Air Permitting					
Level 2 Subset Activities					
MT_2001	Perform Ambient Air Quality Modeling	05MAR04A	28JUN04	24MAR04*	28JUN04
MT_2002	Prepare Air Permit Application	31MAR04A	14JUL04	31MAR04*	14JUL04
MT_2003	Agency Review	14JUL04*	09OCT04	14JUL04*	09OCT04
MT_2005	Submit Air Permit Application		14JUL04*		14JUL04*
MT_2004	Receive PTI & Commence Major Construction		09FEB05*		09FEB05*
Balanced Draft					
Level 2 Subset Activities					
MT_6000	Release A/E to Commence Balanced Draft E&D	31MAR04A	09JUL04	31MAR04*	08MAY04
MT_6001	AE / OEM Detailed Balanced Draft E&D	01JAN05*	01JUL05	01JAN05*	01JUL05
MT_6003	Procure Balanced Draft Materials	02MAY05*	01FEB06	02MAY05*	01FEB06
MT_6002	Perform Balanced Draft Modifications	17MAR06*	30MAR07	17MAR06*	30MAR07
Boiler Modifications					
Airheater Basket Modifications					
MT_5013	Prepare and Issue Technical Specifications	15AUG05*	31AUG05	15AUG05*	31AUG05
MT_5012	Procure Airheater Baskets	26SEP05*	01FEB06	26SEP05*	01FEB06
MT_5015	Install Airheater Baskets	18MAR06*	30MAR07	18MAR06*	30MAR07
Slag Control Devices					
MT_5000	Release A/E for Slag Control Device E&D	31MAR04A	15JUN04	31MAR04*	08MAY04
MT_5001	Perform Detailed Slag Control E&D	01NOV04*	01AUG05	01NOV04*	01AUG05
MT_5002	Procure Slag Control Materials	01MAY05*	01FEB06	01MAY05*	01FEB06
MT_5005	Install Slag Control Devices	17MAR06*	30MAR07	17MAR06*	30MAR07
Superheat Slag Monitoring System					
MT_5003	Release A/E for Slag Monitoring E&D for CI	31MAR04A	15JUN04	31MAR04*	08MAY04
MT_5004	Perform Detailed Slag Monitoring E&D	01NOV04*	01AUG05	01NOV04*	01AUG05
MT_5006	Procure Slag Monitoring Materials	01MAY05*	01FEB06	01MAY05*	01FEB06
MT_5008	Install Slag Monitoring Devices	17MAR06*	30MAR07	17MAR06*	30MAR07



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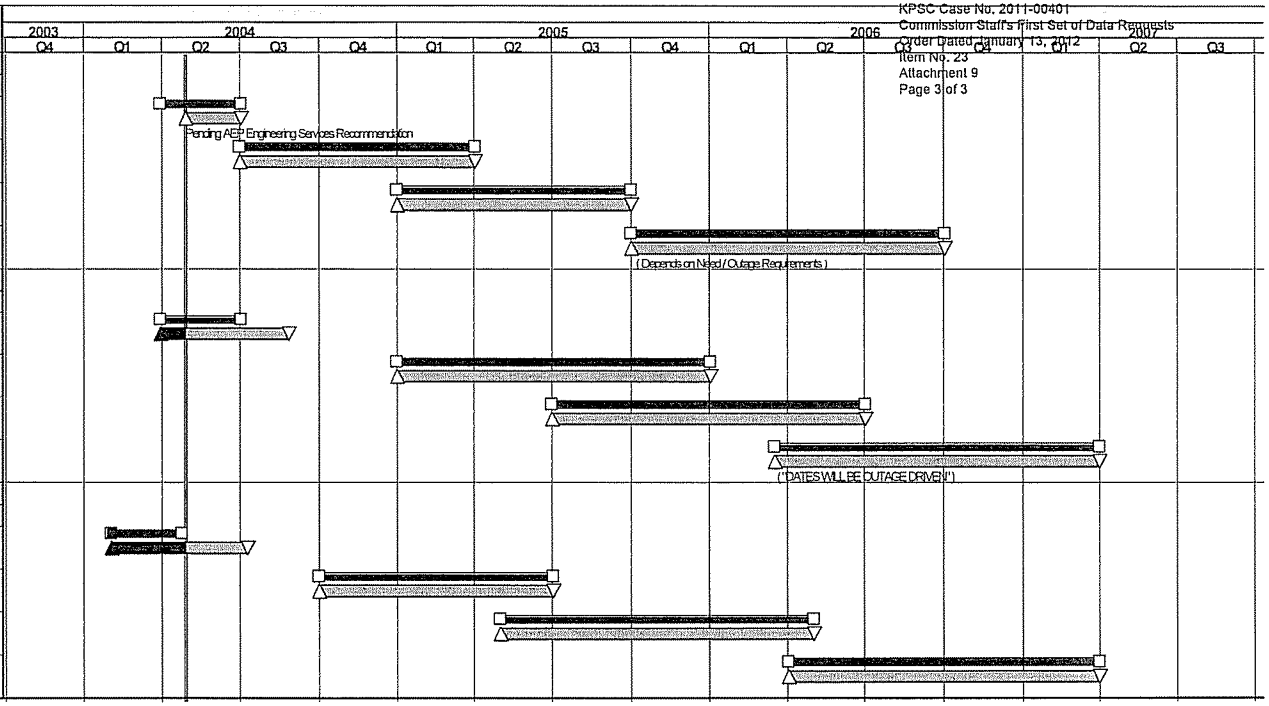
AEP
Environmental Projects Summary
Mountaineer

AMERICAN ELECTRIC POWER

Marian Tanner

Date	Revision	Checked	Approved
08APR04	Revision 3		

Activity ID	Activity Description	Early Start	Early Finish	Target 1 Early Start	Target 1 Early Finish
Coal Blending					
Level 2 Subset Activities					
MT_8000	Release A/E to Evaluate Requirements	29APR04*	01JUL04	31MAR04*	01JUL04
MT_8001	Perform Detailed Coal Blending E&D	01JUL04*	01APR05	01JUL04*	01APR05
MT_8002	Procure Coal Blending Materials	01JAN05*	01OCT05	01JAN05*	01OCT05
MT_8003	Install Coal Blending Equipment	01OCT05*	01OCT06	01OCT05*	01OCT06
Control Modernization					
Level 2 Subset Activities					
MT_7000	Release A/E to E/D Control System Modernization	31MAR04A	27AUG04	31MAR04*	01JUL04
MT_7001	Perform Detailed Control Modernization E&D	01JAN05*	01JAN06	01JAN05*	01JAN06
MT_7002	Procure Control System Equipment	01JUL05*	01JUL06	01JUL05*	01JUL06
MT_7003	Install Control Modernization Modifications	18MAR06*	31MAR07	18MAR06*	31MAR07
SO3 Mitigation					
Level 2 Subset Activities					
MT_9000	Release A/E for SO3 Mitigation E&D for CI	02FEB04A	09JUL04	02FEB04A	24APR04
MT_9001	SO3 Mitigation Engineering and Design	01OCT04*	01JUL05	01OCT04*	01JUL05
MT_9004	Procure SO3 Mitigaton Equipment	02MAY05*	01MAY06	02MAY05*	01MAY06
MT_9003	Install SO3 Mitigation System	03APR06*	31MAR07	03APR06*	31MAR07



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AEP
Environmental Projects Summary
Mountaineer

AEP AMERICAN® ELECTRIC POWER

Marlan Tanner

Date	Revision	Checked	Approved
03APR04	Revision 3		

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated Click here to type order date
Item No. 24
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to page 5 of the Walton Testimony, line 14. It states, "[t]he project is currently in Phase 1." Explain when Phase 1 began.

RESPONSE

Phase I for this project was formally restarted approximately in October 2011.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 5 of the Walton Testimony, lines 21-22.

a. Explain whether an architect/engineer ("A/E") has been engaged for this project? If so, who is the A/E?

b. Describe the process of how the A/E was, or will be, selected.

RESPONSE

a. Yes, Worley Parsons has been selected as the A/E.

b. Following due diligence, AEP maintains contractual agreements with several A/E firms, including Worley Parsons. These agreements have established technical and commercial terms and conditions and hourly billing rates for specific skill sets, negotiated with each A/E with the intent to maintain competitiveness across the organizations. AEP reviews in-progress and pending projects across the fleet, ascertains which of the A/Es are most qualified to support specific projects and their current workload versus available resources, and then assigns the work to an A/E while maintaining reasonable parity.

WITNESS: Robert L Walton

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated January 13, 2012
Item No. 26
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to page 5 of the Walton Testimony, lines 20-23. It states, "[t]he formal process begins with the preparation and approval of a Capital Improvement Requisition (CI) after which an architect engineer (A/E) is engaged to perform the engineering, design, and feasibility studies for Phase I and the ensuing phases of the project ."

a. Provide a copy of the AEP Board approved CI.

b. Provide the date the CI was approved by the AEP Board.

RESPONSE

a. Please see page 2 of this response.

b. The CI was approved by the AEP Subcompany Board on January 26, 2012.

WITNESS: Robert L Walton

Capital Improvement Approval Requisition

Company: Kentucky Power Company Version 4

Project: 000009633 Revision - Big Sandy Unit 2 FGD and Associated Work Retrofit Project - Phase 1
Louisa, KY

Description: Install a Dry Flue Gas Desulfurization (DFGD) system with an integrated pulse jet fabric filter designed to achieve up to 98% SO_2 removal and reductions in mercury, acid gasses, total particulate matter, and other hazardous air pollutants.

The original version of this CI in 2004 was to perform the preliminary engineering and design necessary to define the scope, schedule and costs required to retrofit a Wet Flue Gas Desulfurization (WGFD) at Big Sandy Unit 2 as part of the Fleet SO_2 Compliance Plan.

Versions 2 and 3, approved in February 2005 and November 2005, respectively, provided funding to continue preliminary engineering and design as well as allowing Design Review Board (DRB) review of the project for FGD installation.

The WFGD scope of work was suspended in 2006 after an assessment indicated that the costs to retrofit the unit had increased substantially along with a significant decrease in fuel savings affiliated with burning a higher sulfur coal.

Reason for Revision: In order to comply with the 2007 New Source Review (NSR) consent decree with the Department of Justice, Unit 2 at Big Sandy must be retrofitted with FGD technology by December 31, 2015. This revision is required due to the significant change in scope from Wet FGD to Dry FGD technology. This DFGD technology with an integrated pulse jet fabric filter is the preferred technology due to its lower cost while still achieving the required SO_2 reduction efficiencies burning 4.5 lb/mm BTU sulfur coal.

This project will be executed in three phases. This CI revision requests funds to continue Phase 1 efforts. During Phase 1, project planning, conceptual engineering and design and feasibility studies are needed to facilitate environmental permitting and to establish the project definition and scope. Deliverables for Phase 1 will include a project execution plan, an overall project schedule, and a budgetary cost estimate to validate the current long range plan forecast. Also during Phase 1, the Architect/Engineer and FGD supplier will be released to proceed with conceptual engineering and design to support critical path environmental permitting and construction planning activities. A Phase 2 CI revision will be submitted in 4Q 2012 for detailed engineering and design.

The total combined cost for the Big Sandy Unit 2 Dry FGD and Associated projects, DFGD landfill and haul road projects is estimated at $940 million.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$ 29,622,572	$ (1,217,022)	$ 28,405,550

Cash Flow:

	Prior Years	2011	2012	Future Years	Total
Capital	$ 17,855,566	$ 2,027,941	$ 8,522,043	$ -	$ 28,405,550
Removal	$ -	$ -	$ -	$ -	$ -
Total to be Authorized	$ 17,855,566	$ 2,027,941	$ 8,522,043	$ -	$ 28,405,550
Associated O&M	$ -	$ -	$ -	$ -	$ -

Start Date: 2/1/2012 **Completion Date:** 6/30/2016 **In Service Date:** 6/30/2016

Regulatory Cost Recovery: Kentucky Power Company – Generation - $28.4M (100%)
- $28.1M (99%) KY Base Rate Case Filing, TYE TBD; effective TBD
- $0.3M (1%) FERC Annual Formula Rate Update, TYE 12/31/16; effective 6/1/17

Funding: 2012 Control Budget *(included in IRC Presentation)* Yes Offset Source N/A

Requested future year funds are included in the last official Forecast

Approved By: S. Burge/G. Pauley/M. McCullough/N. Akins **Approved On:**

Capital Improvement Approval Requisition

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total
Previously Approved Amount	29,622,572	-	29,622,572
This Submission	(1,217,022)	-	(1,217,022)
Total	$ 28,405,550	$ -	$ 28,405,550

2012 Direct Cost Budget Funding			Budget Offset Source and Amount
In Budget	$	6,778,425	
Budget Offset			

Requested future year funds are included in the last official Forecast.

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt ≤ $ 10m	SVP, Business Unit	Burge, S.	See electronic approval attached	12/16/2011
amt ≤ $ 10m	Operating Company President	Pauley, G.	See electronic approval attached	12/28/2011
amt ≥ $ 10m	EVP - Generation	McCullough, M.		1/19/12
amt ≥ $ 20m	President & CEO	Akins, N.		1/19/12
CP&B Review	Senior Vice President	Dieck, L.		1/18/12

Project Contacts

Contact	Name	Telephone
Project Manager	Edward V. Gilabert	614-716-1765
Requisition Detail Provider	Edward V. Gilabert	614-716-1765

Capital Improvement Approval Requisition

Reason for Revision (Version 4)

Kentucky Power and the electric utility industry are facing new EPA air regulations. The Clean Air Transport Rule will result in significant reductions in SO_2 and NO_x emissions. The Electric Generating Unit MACT (Maximum Achievable Control Technology) Rule will impose stringent limits on emissions of hazardous air pollutants including mercury, acid gases, and total particulate matter as a surrogate for non-mercury metals from coal and oil-fired electric generating units.

In addition, Kentucky Power is subject to the mandates of a consent decree executed with the Department of Justice under the New Source Review (NSR) provisions of the Clean Air Act. Kentucky Power is currently obligated by the Consent Decree to install a FGD at Big Sandy Unit 2 by December 31, 2015.

The Wet FGD scope of work was suspended in 2006 after an assessment indicated that the costs to retrofit the unit had increased substantially along with a significant decrease in fuel savings affiliated with burning a higher sulfur coal.

This revision is required due to the significant change in scope from Wet FGD to Dry FGD technology. This DFGD technology with an integrated pulse jet fabric filter is the preferred technology due to its lower cost while still achieving the required SO_2 reduction efficiencies burning 4.5 lb/mm BTU sulfur coal.

This project will be executed in three phases. This CI revision requests funds to continue Phase 1 efforts. During Phase 1, project planning, conceptual engineering and design and feasibility studies are needed to facilitate environmental permitting and to establish the project definition and scope. Deliverables for Phase 1 will include a project execution plan, an overall project schedule, and a budgetary cost estimate to validate the current long range plan forecast. Also during Phase 1, the Architect/Engineer and FGD supplier will be released to proceed with conceptual engineering and design to support critical path environmental permitting and construction planning activities. A Phase 2 CI revision will be submitted in 4Q 2012 for detailed engineering and design.

Justification for Version 3

Additional funding is being requested to continue Phase IIa engineering and design and to procure Long Lead time material/equipment required to retrofit a WFGDS at Big Sandy Unit 2 as part of the Fleet SO_2 Compliance Plan. Also included in this revision is the funding for two payments to the OEM as required in the milestone payment schedule of the OEM contract: (1) 8% payment upon acceptance of the contract and (2) 8% payment for release for detailed engineering.

Justification for Version 2

To Perform Phase IIa engineering and design to complete approximately 15% of the engineering, allowing Design Review Board (DRB) review of the project for FGD installation. As part of the Phase IIa engineering and design, the Architect/Engineer (AE) will conduct a Big Sandy Unit 1 feasibility study on incremental issues with adding WFGD and/or SCR to BS Unit 1 for the possibilities for dealing with the mercury control issues.

Capital Improvement Approval Requisition

Justification for Original Version

- The "Fleet Compliance Design Basis Rationale for WFGD & SCR Projects" established protocol to determine fleet emissions compliance under five different regulatory scenarios. A computer model, Multi-Emissions Compliance Optimization (MECO) was developed to evaluate fleet compliance. Under all five scenarios, Big Sandy Unit 2 will require installation of WFGD technology by 2010.
- In order to meet SO_2 compliance requirements in 2010, funding for Phase I is requested to perform preliminary engineering, design, scheduling, and planning to obtain cost estimates to retrofit WFGD technology at the Big Sandy Plant.
- At the completion of this Phase I work, Phase II will build upon the conceptual engineering and budgetary cost estimates from Phase I and continue with detailed engineering & design to generate construction labor Request for Quotation (RFQ) Packages. These packages will be competitively priced and become the basis for the Phase III requested labor funding.

AEP System Wide, Least Cost Compliance Planning

The Big Sandy scrubber decision was made in the context of an AEP system wide environmental compliance analysis which determined that scrubbing Big Sandy was part of a least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the MECO (multi-emissions compliance optimization) model, a unique mixed integer programming model which solves for the least cost environmental compliance plan. This proprietary model is a sophisticated analytic tool that allows the company systematically to weigh the costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO_2, NOx, mercury and CO_2).

In July 2003, the company analyzed a variety of potential environmental scenarios, including the current SO_2 and NOx regulations faced by the company under Title IV and the NOx SIP Call under the Clean Air Act of 1990 plus a variety of additional reductions anticipated at the time under EPA's future regulatory initiatives for fine particulates, visibility and ozone attainment initiatives. In addition, potential multi-emissions such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Big Sandy scrubber decision was always part of the least cost compliance plan.

In January 2004, AEP reanalyzed the compliance plan in light of the proposed EPA clean air interstate rule (CAIR) and the mercury rules (proposed in December 2003) and reached an identical conclusion. The Big Sandy scrubber was again found to be an economic decision.

In addition, under all the scenarios analyzed, the fuel and operating costs of Big Sandy plus the scrubber investment (incremental capital) and additional O&M costs were well below market prices for power now and projected in the future, indicating that the investment in Big Sandy was sound and robust relative to market.

Capital Improvement Approval Requisition

Associated Environmental Operability and Reliability Work

The AEP Fleet Compliance Plan to address emissions regulations in the most cost-effective manner relies, in part, on the efficient and reliable operation of the controlled units. As a means of providing greater operational assurance in this area and addressing overall reliability, the following associated projects, when justified, will be undertaken as a part of the WFGD retrofit:

- Balance Draft Conversion – The installation of WFGD technology necessitates the installation of new induced draft fans to overcome the additional system pressure drop (resistance). The incremental cost of converting the steam generator and auxiliary equipment, including the flue gas path, to allow furnace operation at a slight negative pressure, when compared to the operational, ongoing O&M and the working environment benefits justifies implementation of this project.

- SO_3 Mitigation System - A portion of the SO_2 generated during coal combustion is further oxidized in the boiler and in the SCR, creating SO_3. Some SO_3 is removed in the air heater and the flue gas desulfurization system. However, without additional control and burning design basis coal, the stack SO_3 levels are expected to exceed 20 ppmv when the SCR is not in operation, and 40 ppmv when the SCR is in operation. SO_3 of this magnitude in the flue gas that exits the stack forms a secondary plume with a characteristic blue color and elevated visual opacity. To address this issue, the installation of a trona (sodium sesquicarbonate) injection system will be considered to reduce the SO_3 emissions to 10 ppmv or less.

- Unit Controls Modernization – The installation of WFGD technology will utilize a state of the art control system. To integrate this new, modern DCS system into the existing unit controls, even if possible, would represent a significant undertaking. "Stand-alone" controls for the WFGD are not desirable.

- Steam Generator Additions – Building on the fuel flexibility benefits for Big Sandy Unit 2 to combust coals with sulfur contents as high as 4.5#/MBtu, the steam generator will require additional furnace slag control devices (water cannons and/or blowers), modification or replacement of the current burners, furnace nose addition to increase water wall surface area, and furnace overlay to mitigate increased furnace corrosion.

Conclusion

- Since this is a preliminary engineering CI, there has not been an economic analysis performed or strategic or risk scores identified. Information gathered under this CI will be used in part to develop a future economic analysis and strategic and risk scores for the detailed engineering, procurement and construction of the WFGD system and associated landfill.

- Funding for Phase I engineering and design for a WFGD is required to support development of a Phase II CI, expected to be routed for approval during the fourth quarter of 2004. Funding is also requested for the studies associated with balance draft conversion and steam generator additions to define upfront the impacts and costs of these potential design and operational improvements.

- This strategy supports the construction of a WFGD for Big Sandy Unit 2 for operation in the 2010 timeframe.

- The Wet FGD scope of work was suspended in 2006 after an assessment indicated that the costs to retrofit the unit had increased substantially along with a significant decrease in fuel savings affiliated with burning a higher sulfur coal. Version 4 of this CI is required due to the significant change in scope from Wet FGD to Dry FGD technology. This DFGD technology with an integrated pulse jet fabric filter is the preferred technology due to its lower cost while still achieving the required SO_2 reduction efficiencies burning 4.5 lb/mm BTU sulfur coal.

Capital Improvement Approval Requisition

Alternatives Considered

- The SO_2 Compliance Plan has evaluated several alternatives such as the procurement of SO_2 allowances on the open market and/or fuel switching, but these alternatives will not provide the amount of SO_2 allowance required to support AEP's coal-fired electrical generation fleet.

- Retire Unit and replace generation with natural gas combined cycle options

Background Information

- In accordance with the fleet SO_2 compliance plan, the WFGD technology is targeted to be capable of 98% SO_2 removal efficiency. This level of removal will allow for an expected 95% reduction in annual emissions during all modes of operation. The reagent of choice will be limestone, and the technology will provide the operational flexibility to produce a disposable gypsum byproduct. The WFGD design criteria will maintain maximum fuel flexibility for the unit. A wider range of coals, to include high sulfur coal, has been incorporated in the design criteria for the WFGD.

- The WFGD design basis for the unit must include provisions for adding future emission control equipment for reduction of mercury and possibly other emissions without relocation of equipment. This approach will allow for implementation of current available technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

- A computer model, Multi-Emissions Compliance Optimization (MECO), was developed to guide the selection of methods for fleet compliance under five different regulatory scenarios. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. The methods considered viable are allowance purchases, fuel switching, capacity retirement, and building new equipment. This model identified the Big Sandy Unit 2 as requiring a WFGD in 2009 based on the current assumptions for SO_2 credit value and availability.

Associated / Future Projects

- CI 000008348 has been approved to perform preliminary engineering, design, and environmental work for air modeling and permitting of a future FGD and future FGD landfill for Big Sandy Unit 2.

- BS Haul Road to Landfill

Kentucky Power Company

REQUEST

Refer to page 9 of the Walton Testimony, lines 5-7. In discussing Total Evaluated Cost ("TEC"), it states, "[t]he final award is based on the TEC and safety performance of those bidders, along with ancillary considerations such as a financial risk assessment, any pricing discounts offered for multiple-unit awards, negotiated shared risk/reward programs, and similar factors."

a. Describe the extent to which AEP encountered any of these factors in conjunction with its previous scrubber construction projects.

b. If the answer is yes to part a. of this Item, identify which factors were encountered and provide the additional cost to the project affected.

c. Explain whether any of the factors might come into play in installing the type of scrubber and environmental facilities planned at Big Sandy Unit 2.

RESPONSE

a. AEP has not encountered such instances with previous scrubber construction projects where the factors listed prevented award to the preferred company based on the TEC.

b. N/A

c. AEP does not expect any of these factors to come into play for the DFGD project at Big Sandy 2.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 10 of the Walton Testimony, lines 2-16. It discusses AEP's cost management process. For each of the FGD systems discussed on page 5 of the Walton Testimony, line 4, provide the Phase 1 estimated cost and the completed in-service cost.

RESPONSE

Please see the Company's response to KPSC 1-23.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 11 of the Walton Testimony, lines 16-19, which indicate that the "FGD System Equipment Supplier is selected from a competitive evaluation process based on AEPSC ["AEP Services Company"] performance and technical specifications. A similar process is utilized for the selection of construction labor companies to perform the field installation of the equipment." Does AEP select different vendors throughout its fleet, or the same overall vendor for familiarity with the product/vendor?

RESPONSE

AEP's philosophy as relates to engineered systems, such as FGD's, is to employ duplication to the maximum extent possible across the fleet. This allows for cost savings associated with bulk purchasing discounts as well as savings associated with maintaining and sharing common spare parts. It also allows for the sharing of best practices across facilities in the operation and maintenance arena, further enhancing the value of commonality. AEP does not necessarily utilize the same constructors, but employs the most cost-effective contractor for the specific scope and location across the fleet.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 15 of the Walton Testimony, lines 21-23, which indicates that technical and economic evaluations were performed to compare and contrast the wet FGD and dry FGD technology options that may be applied while burning coals with different sulfur contents, up to 4.5 lbs. SO2/mmBtu.

a. Describe in detail the impact the sulfur content played in selecting the appropriate SO2 removal technology.

b. Would the desulfurization selection process change if the sulfur level changes?

c. P rovide examples of technologies which will meet the EPA mandates as related to high and low sulfur coal.

RESPONSE

a. Technical and economic evaluations were based on a 0.09 lb/mmBTU SO2 emission rate, corresponding to a 98% removal efficiency based on an uncontrolled inlet SO2 of 4.5 lb/mm BTU. This provides the appropriate margin to satisfy the limits set forth in the CSAPR and MATS rules and supports the ability to attain further reductions which might be required by the pending SO2 1-hour National Ambient Air Quality Standard (NAAQS).

b. No.

c. The lime based Circulating Dry Fluidized Bed Scrubber with Pulse Jet Fabric Filter system and the limestone based Forced Oxidized Spray Tower Wet FGD with Wet ESP system are examples of technologies that are capable of meeting EPA mandates and are capable of 98% removal efficiency of coal with SO2 of 4.5 lb/mmBTU.

The spray dryer absorber (SDA) FGD is limited to a maximum uncontrolled inlet SO2 of 3.0 lb/mmBTU at a 95% removal efficiency. This technology is unable to achieve the desired 0.09 lb/mmBTU SO2 emission rate, limits fuel flexibility, and was subsequently excluded in the technology evaluation.

For more information, please refer to the Big Sandy Unit 2 Flue Gas Desulfurization (FGD) Technology Evaluation in Item No. 30, Attachment 1 to this response for which confidential protection is being sought.

WITNESS: Robert L Walton

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ENGINEERING REPORT COVER SHEET

TITLE: **Big Sandy Unit 2 Flue Gas Desulfurization (FGD) Technology Evaluation and Selection**

REPORT NUMBER: **BS2-FGDPE-111311**

PROJECT: Big Sandy Unit 2 – FGD Project

REVISION: 0

DATE: 11/13/2011

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TABLE OF CONTENTS

Executive Summary

This technical evaluation was performed to compare and contrast the wet and dry flue gas desulfurization (FGD) technologies that may be applied to Big Sandy Unit 2, located in Louisa, KY. The evaluation of the FGD technology options contained herein considered environmental and technical performance, retrofit constraints, environmental and technical collateral impacts, and economics.

The Alstom NID FGD System (NID) with integral Pulse Jet Fabric Filter (FF), a dry FGD technology, is recommended for Big Sandy Unit 2 over the other evaluated technologies, which included the Spray Dryer Absorber (SDA) Technology with Pulse Jet Fabric Filter (FF), Circulating Dry Fluidized Bed Scrubber (CDS) Technology with Pulse Jet Fabric Filter (FF), and Limestone Forced Oxidized Spray Tower Wet FGD (WFGD) Technology with a Wet Electrostatic Precipitator (WESP). Integral to the recommendation of the NID FGD technology for Big Sandy Unit 2 is the future plan to burn a medium sulfur fuel (max 4.5 lb SO_2/mmBtu) with 98% SO_2 removal efficiency. As a result, this FGD technology evaluation and economic analysis is based on a 4.5 lb SO_2/mmBtu fuel with 98% removal efficiency, which equates to a 0.09 lb SO_2/mmBtu emission rate. Considering equivalent SO_2 removal efficiencies among the evaluated FGD technologies for the design basis fuel (with the exception of the SDA FF option which does not meet the aforementioned design basis requirements), the NID FGD technology is the favored FGD technology for Big Sandy Unit 2 based on the following:

- Lowest water consumption
- Lowest auxiliary power requirements
- Lowest reagent usage
- Lowest total solid waste production
- Smallest equipment footprint
- Technology best supporting Activated Carbon Injection (ACI) for mercury removal
- Technology best supporting SO_3 removal
- Technology best supporting other hazardous air pollutants (HAPs) removal
- Technology best supporting future NPDES permit compliance for plant outfalls
- Lowest total evaluated cost on 20 year NPV basis and 30 year Cumulative Present Worth basis (capital and O&M).

Introduction

Big Sandy Unit 2 is an 800 MW (net) pulverized coal-fired boiler with a design heat input of 8,180 mmBtu/hr. The selected fuel option for this FGD technology evaluation is a blend of Central and Northern Appalachian coal with the following design parameters, representing the upper end of the expected sulfur content for fuels to be burned at Big Sandy Unit 2 post FGD retrofit:

- 12,490 Btu/lb High Heating Value (HHV)
- 0.05% Chlorine (Cl) (by weight)
- 4.5 lb/mmBtu SO_2 (uncontrolled).

Further, target emissions for the FGD retrofit at Big Sandy Unit 2 are as follows:

- SO_2 $\leq$ 0.09 lb SO_2/mmBtu
- Total Particulate (combination of filterable and condensable) $\leq$ 0.030 lb/mmBtu
- Opacity $\leq$ 20%
- Mercury $\leq$ 1.0 lb/TBtu
- Hydrogen Chloride (HCl) $\leq$ 0.0020 lb/mmBtu (SO_2 limit can be used instead of HCl limit with an installed FGD system).

Target emissions may change due to potential revisions to the Electric Generating Unit MACT (Maximum Achievable Control Technology) proposal (a.k.a. "HAPs Rule") that was proposed as a draft rule for comment by the USEPA on March 16, 2011 with final issue of the rule expected by mid December 2011. However, it is currently anticipated that Big Sandy Unit 2 will be required to install controls for the above listed target emissions by the end of 2015.

Currently, the unit removes particulate emissions from the flue gas stream exiting the boiler by means of a "cold-side" electrostatic precipitator (ESP) positioned downstream of the air heater, and NOx emissions are controlled by a Selective Catalytic Reduction (SCR) system. Big Sandy Unit 2 currently does not have any additional controls for SO_2, SO_3, mercury (Hg), or hazardous air pollutants (HAPs) like Hydrochloric Acid (HCl). Based on this information, the following graphic (see Figure 1) depicts potential air quality control system (AQCS) arrangements for Big Sandy Unit 2 considering the current boiler and cold-side ESP arrangement with provisions for SO_2, SO_3, NOx, particulate matter (PM), mercury (Hg), and hazardous air pollutants (HAPs) control.

Within each category of wet and dry FGD technology options, specific FGD types were considered and evaluated based on their general design and capability of being applied to Big Sandy Unit 2. In the section titled "Other Technologies Considered" later in this report, several FGD systems that are being used in the industry are discussed, with reasoning as to why they were not considered as viable options for the Big Sandy Unit 2 application. Ultimately, four technologies emerged for detailed comparative analysis:

- Limestone based Forced Oxidized Spray Tower Wet FGD (WFGD) with Wet ESP (WESP)
- Lime based NID Dry FGD System (NID) with integral Pulse Jet Fabric Filter (FF)
- Lime based Circulating Dry Fluidized Bed Scrubber (CDS) with Pulse Jet Fabric Filter (FF)
- Lime based Spray Dryer Absorber (SDA) with Pulse Jet Fabric Filter (FF).

The Limestone based Forced Oxidized (LSFO) Spray Tower Wet FGD was selected for detailed comparative analysis primarily based on its usage in the AEP Eastern Fleet for SO_2 control. The LSFO Wet FGD has also been applied at other facilities in the industry that burn mid-to-high sulfur fuels, and is considered a mature technology that is suitable for the application at Big Sandy Unit 2. The dry FGD technologies utilizing recycled material collected in the downstream fabric filter were selected for comparative analyses based on capital cost, footprint, turndown, and power consumption benefits, future HAPs requirements, and future NPDES outfall requirements. Note the SDA FF option is not capable of meeting the Big Sandy Unit 2 FGD technology evaluation design basis (4.5 lb SO2/mmBtu inlet with 98%

removal efficiency), so it is excluded as a viable option in the economic and detailed comparative analyses.

EQUIPMENT LINE-UP FOR FGD TECHNOLOGY OPTIONS
BIG SANDY UNIT 2
Selected for FGD Evaluation – CAPP/NAPP, 4.5 lb SO_2/MMBtu

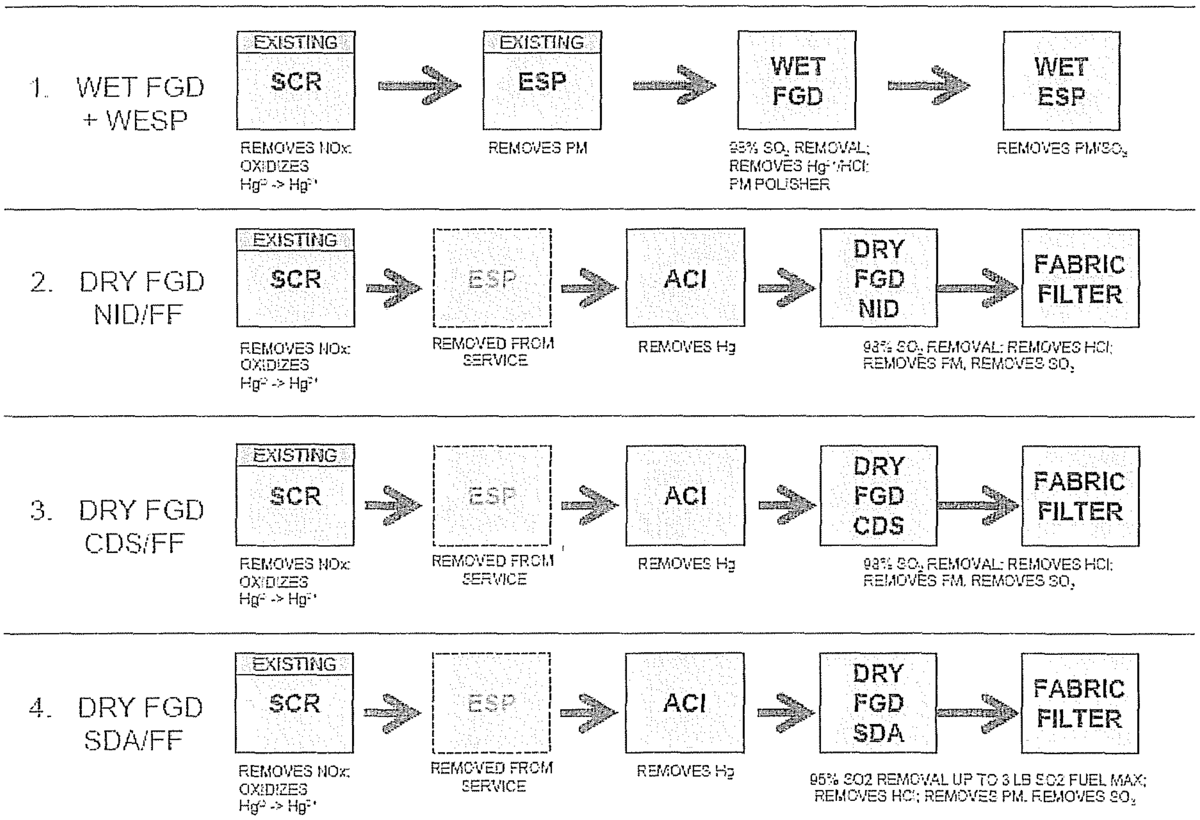

Figure 1

Conclusion & Recommendation

Based on the detailed evaluation documented in this engineering report, the Alstom NID FGD system with integral Pulse Jet Fabric Filter is recommended for Big Sandy Unit 2 over the other evaluated FGD technology options because it offers excellent emissions control performance based on the unit's operating parameters, best minimizes the impact to the plant's overall environmental footprint, and offers the lowest total evaluated cost. A NID FGD system at Big Sandy Unit 2 will effectively control SO_2 emissions while minimizing water usage, auxiliary power consumption, equipment footprint, reagent usage, and solid waste production. In addition, the NID FGD system will allow for effective co-benefit control of emissions such as mercury, SO_3, and other HAPs while mitigating the risk of future NPDES permit compliance for plant outfalls.

Below is a quantitative/qualitative analysis summary of the key environmental and technical areas of comparison between the three applicable FGD technologies for Big Sandy Unit 2. The highlighted boxes indicate which technology was favored when directly analyzed using Big Sandy Unit 2 design and operating parameters.[1] For all parameters evaluated, the NID FGD System with integral Pulse Jet Fabric

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[1] Reference Attachment BS-01 - AEP FGD Program Engineering Calculations

Filter was favored or provided equivalent performance/benefits compared to the other technologies. In addition, the NID FGD system with integral Pulse Jet Fabric Filter offered the lowest total evaluated cost on a 30-year Cumulative Present Worth basis (reference the Economic Analysis section of this report), thus making it the recommended FGD technology for Big Sandy Unit 2.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Uncontrolled Inlet SO_2 (lb/mmbtu)	▨ 4.5		▨ 4.5	▨ 4.5
Outlet SO_2 (lb/mmbtu)	▨ 0.09		▨ 0.09	▨ 0.09
SO2 Removal Efficiency (%)	▨ 98		▨ 98	▨ 98
Annual Water Consumption (MGY)	▨ 572		▨ 569	624
Aux Power Usage (MW)	▨ 15		16	31
Annual Reagent Usage (TPY)	▨ 216,980		223,380	236,351
Total Solid Waste Production (TPY)	▨ 634,034		640,356	643,446
Equipment Footprint (acres)	▨ 3.52		3.54	4.56
Technology that best supports ACI (Mercury Removal)	▨		▨	
Technology that best supports SO3 removal	▨		▨	
Technology that best supports other hazardous air pollutants (HAP's) removal	▨		▨	▨
Technology that best supports future NPDES permit compliance for plant outfalls	▨		▨	
Incremental Comparison of 30 yr Cumulative Present Worth (CPW) of OPCO Revenue Requirements	▨ [redacted]		$[redacted]	$[redacted]

▨ Indicates which Technology is favored

☐ Indicates SDA/FF doesn't meet 4.5 lbSO2/mmbtu design basis @ 98% removal Efficiency

Key considerations influencing the FGD technology recommendation of the NID FGD system for Big Sandy Unit 2 and details of the FGD technology options detailed comparative analysis are further discussed throughout the remainder of this report. References to industry technical reports, analyses, and vendor-supplied FGD process information to support this technical evaluation are also included in the appendix.

Economic Analysis

A key input to this FGD technology evaluation was the economic analysis (including both 20-yr NPV analysis and 30-yr Cumulative Present Worth analysis) performed for the Big Sandy Unit 2 FGD technology evaluation. The economic analysis was based on four FGD technology options and the 4.5 lb SO_2/mmBtu fuel option as follows:

FGD Technology	Fuel Option
	4.5 lb/MMBtu SO_2
Dry FGD - SDA & FF	X
Dry FGD - NID & FF	✓
Dry FGD - CDS & FF	✓
Wet FGD - Spray Tower & WESP	✓

It is important to note that each economic analysis case identified above by a green check mark is "technically viable" from an emissions compliance standpoint, meaning compliant with the proposed HAPs regulations based on the information available at the writing of this report. For example, the FGD technology options considered control provisions for SO_2, SO_3, PM, Hg, and HCl to comply with the anticipated HAPs Rule. As already noted, the SDA FF option is not capable of meeting the Big Sandy Unit 2 FGD technology evaluation design basis (4.5 lb SO2/mmBtu inlet with 98% removal efficiency), so it is excluded from the economic analysis.

20-yr NPV Analysis

AEP Generation Business Services' Spread Option Model provides a make vs. buy analysis and ranking of the FGD technology options via a 20-yr NPV economic analysis.[2] For the three evaluated cases identified above, the NID FF technology was the clear least cost alternative.

30 year Cumulative Present Worth Analysis

The economic analysis performed for the Big Sandy Unit 2 FGD technology evaluation also included a 30-yr Cumulative Present Worth analysis of Kentucky Power revenue requirements via AEP Integrated Resource Planning's Strategist Model to provide a total evaluated cost optic. The results, which are summarized below, show the NID FF technology is the least cost alternative among the FGD options evaluated[3].

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[2] Reference Attachment BS-13 - Big Sandy 2 FGD Economic Analysis Summary

[3] Reference Attachment BS-14 - Big Sandy Unit 2 FGD Cumulative Present Worth Analysis

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Capital Cost - Controllable ($M)	[redacted]		[redacted]	$855.0
Annual Variable O&M Cost ($M)	$41.0		$41.0	$10.9
Annual Fixed O&M Cost ($M)	$5.1		$5.1	$5.8
Incremental Comparison of 30-yr Cumulative Present Worth of OPCO Revenue Requirements	[redacted]		[redacted]	$154,454,000

▨ Indicates which Technology is favored
☐ Indicates SDA/FF doesn't meet 4.5 lbSO2/mmbtu design basis @ 98% removal Efficiency

Capital cost estimates developed for the Big Sandy Unit 2 economic analysis were prepared to an accuracy of -15% to +20%. These estimates were leveraged from significant technology evaluations and cost estimates associated with FGD studies for Big Sandy Plant and AEP's years of experience with environmental system construction and startup execution. In addition, competitive proposals were solicited from OEM suppliers for various FGD technologies as part of these studies. These cost estimate inputs were converted to $/kw indicative pricing to allow for scaling of pricing associated with Big Sandy Unit 2's 800 MW unit size.

Several factors contribute to the capital cost differential between the FGD systems. First, as discussed previously, wet FGD systems require more equipment, and likely larger equipment to handle the larger volumes of liquid slurry that are continuously pumped through the wet FGD absorber vessel. The solid waste from the wet FGD must be dewatered, and the wastewater treated for discharge or re-use. More equipment means more foundations, more buildings, more interconnecting piping, wiring, controls, and installation labor. Wet FGD systems also require higher quality materials of construction since they operate below the flue gas saturation temperature, which produces corrosive operating environments. Therefore the absorber vessel, piping, pumps, tanks, valves, instrumentation, etc. must be constructed of high cost alloys and exotic materials. Dry FGD systems are comprised primarily of carbon steel equipment and components since the process is maintained above flue gas saturation, limiting the potential for corrosion. Further, the NID FGD system is a relatively simple and compact design even compared to other dry FGD options, which gives it a clear capital cost advantage.

From an annual variable O&M cost perspective, the main cost driver is the FGD reagent, although byproduct disposal costs represent significant annual expenses. The dry FGD options use lime as their reagent, which is more costly than the limestone reagent used for the wet FGD system. Based on O&M cost information prepared for the Big Sandy Unit 2 FGD economic analysis, the estimated cost of lime (uncontrolled inlet SO_2 value of 4.5 lb SO_2/mmBtu with 98% SO_2 removal efficiency) for the NID FGD system for the is $30.2 M/yr vs. an estimated limestone cost of $6.6 M/yr for the wet FGD system.

Detailed Comparative Analysis

In addition to the economic analysis results, and in support of the FGD technology recommendation for Big Sandy Unit 2, three FGD technology options representing the breadth of applicable technologies, namely WFGD, NID, and CDS were selected for detailed comparative analysis assuming 4.5 lb SO_2/mmBtu fuel and 98% SO_2 removal efficiency. The detailed comparative analysis considered environmental and technical performance, retrofit constraints, and collateral impacts (environmental and technical).

SO_2 Removal

This technology comparison evaluates the technical and environmental impacts of the NID and CDS dry FGD systems with an assumed average outlet SO_2 emission rate of 0.09 lb/mmBtu compared against a wet FGD system with an assumed average outlet SO_2 emission rate of 0.09 lb/mmBtu. The 0.09 lb/mmBtu SO_2 emission rate for the FGD options corresponds to 98% removal efficiency based on an uncontrolled inlet SO_2 of 4.5 lb/mmBtu. This provides appropriate margin under the anticipated 0.20 lb/mmBtu SO_2 emission limit required by the proposed HAPs Rule to allow for further reduction in SO_2 to support the pending SO_2 1-hour National Ambient Air Quality Standard (NAAQS). Note again the SDA FGD system is limited to a maximum uncontrolled inlet SO_2 of 3.0 lb/mmBtu at 95% removal efficiency, so it is not applicable to the 4.5 lb SO_2/mmBtu fuel with 98% SO_2 removal efficiency design basis utilized for this technology evaluation.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Uncontrolled Inlet SO_2 (lb/mmbtu)	4.5		4.5	4.5
Outlet SO_2 lb/mmbtu	0.09		0.09	0.09
SO2 Removal Efficiency (%)	98		98	98

▨	Indicates which Technology is favored
	Indicates SDA/FF does not meet 4.5 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

The outlet SO_2 and removal efficiency is equivalent among the NID FF, CDS FF, and the WFGD WESP options. However, the NID FF option best minimizes the collateral impacts with respect to water consumption, auxiliary power usage, reagent usage, and solid waste production, in addition to being the least cost alternative and providing the best co-benefit emissions control. It is these collateral impacts that significantly affect the overall technical comparative analysis, and are discussed in detail below.

Water Consumption

A wet FGD system would use a calculated 1397 gallons per minute (GPM) of water while the dry FGD CDS and NID systems will use a calculated 1274 and 1280 GPM, respectively,[4] a difference of approximately 9%. Furthermore, the dry FGD systems are capable of using more recycled water proportionally than a wet FGD system, and thus have a lower demand for fresh water supply. The dry FGD systems' ability to use recycled water from other plant systems, coupled with its lower overall water demand, makes the NID system the best choice with respect to water conservation.

Wet FGD systems are typically designed to use a considerable amount of recycled or "reclaim" water, but still require significant amounts of fresh water to wash the mist eliminators. Mist eliminators are the devices that remove large water and slurry droplets from the flue gas before it exits the wet FGD absorber vessel. The mist eliminators must be washed frequently with fresh water to insure consistent performance.[5] Flue gas temperature is higher in a dry FGD system, therefore less water is required for temperature reduction, and the flue gas stays above saturation, or "dry." Since the flue gas remains "dry," dry FGD systems do not utilize mist eliminators, thus there is no need for a mist eliminator wash system.

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[4] Reference Attachment BS-01 - AEP FGD Program Engineering Calculations

[5] Reference Attachment BS-04 - Richard, Ron. RE Consulting "Wet Scrubber O&M Issues." Presentation at Duke Energy Seminar, Sept. 3-5, 2008, p. 21-24.

The additional 117 GPM of water used by the wet FGD compared to the dry FGD NID system translates to approximately 52 Million gallons of additional water annually.[6] The additional usage may not only constrain water availability to the plant, but is significant when considering water conservation and overall water utilization in the region as well.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Water Consumption (GPM)	1280		1274	1397

▨	Indicates which Technology is favored
☐	Indicates SDA/FF does not meet 4.5 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

Considering the average Kentucky household size of three (3) people and the average water consumption of 70 gallons per day per person (70 gallons x 30 days = 210 gallons per month), the average household in Kentucky uses 75,600 gallons per year (210 gallons per month x 3 people x 12 months).[7] Using this average, the savings in water afforded by utilizing a dry FGD (NID or CDS) system versus a wet FGD system at Big Sandy Unit 2 equates to the yearly demand for over 680 households.

Auxiliary Power Usage

All auxiliary power was estimated by Sargent & Lundy as part of the Big Sandy Unit 2 Order of Magnitude Cost Estimate effort, and is based on proposed equipment operating arrangements and components sized specifically for Big Sandy Unit 2.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Aux Power (MW)	15		16	31

▨	Indicates which Technology is favored
☐	Indicates SDA/FF does not meet 4.5 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

It is estimated that a wet FGD would consume approximately 31 MW of auxiliary power, which is 15 MW more than the NID FGD system. The difference in auxiliary power, if calculated annually at an 85% capacity factor translates to 111,690 MWh of annual generation, which is enough electricity to power nearly 7,600 Kentucky households (based on 2007 average annual household electricity consumption for Kentucky as reported by The Energy Information Administration).[8]

Reagent Usage

The reagent used in the dry FGD NID and CDS systems is crushed or pebble lime, while the wet FGD (as compared herein) utilizes limestone. Because of the use of recycled material from the fabric filter, which contains un-reacted lime, the recommended dry FGD NID system will use approximately 1/3 less lime than a dry FGD system operating without recycle. Assuming 4.5 lb SO_2/mmBtu coal, an outlet emission rate of 0.09 lb SO_2/mmBtu, and an 85% capacity factor, the dry FGD NID system is expected to use

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[6] Reference Attachment BS-01 - AEP FGD Program Engineering Calculations.

[7] Reference Attachment BS-05 - Cooperative Extension Service, University of Kentucky, College of Agriculture, "Water Usage",p 2

[8] Reference Attachment BS-06 - Energy Information Administration. "U.S. Average Monthly Bill by Sector, Census Division, and State 2007". http://www.eia.doe.gov/cneaf/electricity/esr/table5.html

216,980 tons/yr of lime. A wet FGD operating at 85% capacity factor on the same fuel is estimated to use 236,351 tons/yr of limestone.[9]

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Annual Reagent Usage (TPY)	216,980		223,380	236,351

▨	Indicates which Technology is favored
	Indicates SDA/FF does not meet 4.5 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

Assuming delivery of reagent to the Big Sandy site will be by railcar with an assumed capacity of 100 tons/car,[10] the estimated annual lime usage by a dry FGD NID system at Big Sandy Unit 2 will result in 193 fewer railcars to and from the site than that required to transport limestone for a wet FGD.

Solid Waste Production

Similar to the reagent usage analysis above, solid waste production from the dry FGD and wet FGD options was calculated and compared based on an assumed 85% capacity factor.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Total Solid Waste Production (TPY)*	634,034		640,356	643,446

▨	Indicates which Technology is favored
	Indicates SDA/FF does not meet 6.0 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

* - Note Total Solid Waste Production includes both FGD byproduct waste production and fly ash production as a cumulative waste to the landfill for all evaluated technologies, and also includes wastewater treatment solids for the WFGD option.

The difference in solid waste is significant when carried out on an annual basis, and results in 9,400 tons of additional solid waste annually if the wet FGD is selected over the dry FGD NID system. This analysis assumed the waste product (gypsum) from the wet FGD would not be sold. While potential markets might exist, the analysis was based on the assumption that a market would not exist for the life of the FGD.

Total Equipment Footprint

Wet FGD systems require more, and generally larger, equipment than dry FGD systems because they handle larger amounts of water and slurry. Furthermore, the wet FGD process incurs an additional step beyond the dry FGD process, in that the solid waste product must be dewatered prior to disposal. This dewatering step requires additional equipment, buildings, and likely the addition of a wastewater treatment facility to treat the water that is removed from the solid waste so it is suitable for discharge or re-use in the plant. More equipment (pumps, tanks, piping, filters, etc.) means larger foundations, bigger buildings, more space required for maintenance activities, etc.

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[9] Reference Attachment BS-01- AEP FGD Program Engineering Calculations

[10] Reference Attachment BS-07 - Center for Global Environmental Education, Hamline University. "Rivers of Life. Rivers Through Time - Compare Cargo Capacity." http://cgee.hamline.edu/rivers/Inquiry/RTT/Rtt_6.htm, p. 1.

Parameter	NID FF	SDA FF	CDS FF	WFGD WESP
Equipment Footprint (acres)	3.52		3.54	4.56

▨	Indicates which Technology is favored
☐	Indicates SDA/FF does not meet 4.5 lbSO2/mmbtu fuel design basis @ 98% removal Efficiency

Overall, the proposed dry FGD NID system equipment footprint for Big Sandy Unit 2 is 23% smaller than a similarly sized wet FGD equipment footprint. This difference accounts for the FGD equipment footprint, and includes the additional space required for water treatment equipment and the increased solid waste production. When considering a retrofit at an existing facility, space is not unlimited, and Big Sandy Plant is no exception. Therefore, the smaller footprint of the dry FGD NID system is a very desirable feature.

Technology Evaluation Background

Additional considerations and background information influencing the FGD technology recommendation of the NID FGD system for Big Sandy Unit 2 are further discussed in the following section.

Wet vs. Dry: Process Fundamentals

The major technical differences between the wet and dry FGD technologies are:

1) A dry FGD system operates above the flue gas water saturation temperature such that all of the water added to the flue gas is evaporated before it leaves the dry FGD absorption vessel or ductwork. This limits the amount of water that can be introduced in the dry FGD process, thus limiting the chemical reactions between the calcium compounds and the SO2. In general, this restricts the technology to low-to-mid sulfur coals. Wet FGD systems rely on greater volumes of water into which the SO2 is rapidly absorbed (scrubbed). In conjunction with the alkali in this slurry, the SO2 is neutralized and precipitated in the absorber reaction tank where sufficient time is provided for the reactions to occur.

2) A wet FGD absorber vessel utilizes a high volume of liquid slurry continuously circulating in the absorber vessel and providing abundant opportunity for SO2 absorption into the slurry droplets. A dry FGD system is comprised of a vessel or length of ductwork where the SO2 is contacted with alkali slurry or moistened dust, and then a downstream fabric filter removes the waste byproduct from the gas flow. Dry FGD systems rely on the absorption and neutralization reactions to take place as the flue gas circulates inside the absorption vessel or duct, and also in the highly reactive dust cake which forms on the surface of the downstream fabric filter media in the fabric filter.[11]

3) Dry FGD systems evaporate the water added to the system and collect the dry waste material in the fabric filter. Thus there is no need for solids dewatering equipment, and there is no wastewater treatment required.[12]

Impact of Fuel Type on FGD Selection

Differences in coal sulfur content can factor significantly into the type of FGD system that is selected, and can also influence the unit's ability to achieve the required SO_2 emissions limits with that technology. Dry

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[11] Reference Attachment BS-02 - B&W Steam: Its Generation and Its Use, 41st Edition, 2005, Chapter 35, p. 13

[12] Reference Attachment BS-03 - B&W Steam: Its Generation and Its Use, 41st Edition, 2005, Chapter 35, p. 12

FGD systems, such as NID, CDS, and SDA, must operate above the water saturation temperature of the flue gas and are thus constrained by the amount of moisture that can be introduced with the lime sorbent.[13] In general, the limits on the amount of water that can be introduced in the dry FGD system in turn limit the chemical reactions between the lime (calcium compounds) and the SO_2. For the SDA technology, the sorbent is thin lime slurry with 20-30% solids that must be evaporated before it leaves the SDA vessel, so the amount of calcium compounds that can come in contact with SO_2 in the flue gas is limited. As a rule of thumb, this restricts the SDA technology to low sulfur coals with 3 lb SO_2/mmBtu inlet max, which is why the SDA FGD system is not applicable to Big Sandy Unit 2 with the 4.5 lb SO_2/mmBtu fuel design basis. For the NID and CDS systems, the sorbent is lime/recycled byproduct moistened dust with < 5% moisture. The moistened dust particles allow greater liquid film surface area and provide an abundance of calcium compounds to absorb/react with the SO2, thus the vapor pressure limitation of SO2 absorption is significantly reduced – this mechanism allows these dry FGD technologies to treat flue gas from medium-to-high sulfur coals with greater than 6 lb SO2/mmBtu.

Wet FGD systems afford greater ability to treat flue gas from high sulfur coal combustion (greater than 10 lb SO_2/mmBtu inlet max) because the process is not limited by operation above the flue gas saturation temperature. This facilitates greater mass transfer in the absorption zone of the absorber vessel as well as longer reaction times in the absorber reaction tank. However, for low-sulfur coal, there is a diminishing return to the SO_2 removal achieved by a more capital and operationally intensive wet FGD system (since there is less SO_2 proportionally to capture). This is affected by the added demands of increased sorbent usage, auxiliary power consumption, water consumption, overall equipment footprint, and solid waste disposal. These collateral impacts must be considered in the overall economic, environmental, performance and operational analyses for determining which FGD technology to use. Industry reports comparing wet and dry FGD systems have also pointed to this fact.

Co-Benefit Emissions Control

Mercury

The addition of either wet or dry FGD at Big Sandy Unit 2 will allow for co-benefit mercury emissions control. A PJFF with ACI is proven effective technology for achieving high levels of mercury capture. Wet FGD systems have been proven to remove mercury as well, but not to the levels of a fabric filter with ACI due to limited net capture of Hg2+ as a result of the not well understood "re-emission" phenomenon.

A key factor in the performance of an ACI system is how well the carbon is distributed into the flue gas. When flue gas enters a dry FGD, it is mixed with a few seconds of residence time in the reactor where the scrubbing reactions occur. Injecting activated carbon upstream of the dry FGD allows the carbon to mix thoroughly in the reactor, which is optimum for insuring proper distribution for mercury adsorption. This is not to say that ACI cannot be optimized in the absence of a dry FGD, but for a retrofit application proper flow distribution could come at a considerably higher cost and higher effort to maintain.

SO_3 / H_2SO_4

Sulfur Trioxide (SO_3) is also a concern, as it contributes to the formation of sulfuric acid (H_2SO_4) mist (SAM) at low temperatures. Dry FGD systems have been proven to better control SAM than wet FGD systems. B&W, a supplier of both wet and dry FGD systems, reported in 2008 that wet FGD systems have limited ability to collect SAM, since it is present as a fine particulate aerosol. Capture of SAM across a wet FGD varies anywhere from 30-50%, whereas a dry FGD and downstream fabric filter are capable of removing SAM emissions down to detection limits.[14]

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[13] Reference Attachment BS-03 - B&W Steam: Its Generation and Its Use, 41st Edition, 2005, Chapter 35, p. 14.

[14] Reference Attachment BS-08 - Tonn, D. P., et al. B&W. "An Emissions Approach to SO3 Mitigation." Technical Paper BR-1815, Presented at Seventh Power Plant Air Pollutant Control "Mega" Symposium, Baltimore MD, 8/2008, p. 3.

A fabric filter downstream of an SDA, NID, or CDS will operate at approximately 150oF - 170°F because the dry FGD absorbers serve to reduce the temperature of flue gas leaving the air preheater and prior to entering the fabric filter.[15] This creates an environment that is more conducive to SO_3 and SAM removal because the lime sorbent in the dry FGD does two things:

1) The addition of the lime reagent lowers the flue gas temperature below the SAM dewpoint, driving the gaseous SO_3 to a mist.[16]

2) The lime reacts with the SO_3 and SAM in the flue gas, forming particulate sulfate compounds, which can then be collected by the highly efficient dust cake on the downstream fabric filters.[17]

Upstream of a wet FGD system flue gas temperatures at the air preheater exit typically 250°F - 350 °F[18] and SO_3 exists primarily as vapor, although some localized cooling in the air heater may cause some of the SO_3 to condense to SAM.[19] The remaining SO_3 at the air heater outlet is then difficult to collect without the presence of lime or another sorbent used for SO_3 removal (Trona, etc.)[20] This is because the higher flue gas temperature decreases the likelihood of SAM formation for collection. Thus, the SO_3 vapor can pass through the wet FGD, condense there to SAM, and remain in the flue gas exiting the stack. Therefore, to achieve the same SO_3/SAM emissions achieved by the dry FGD, a sorbent injection system (hydrated lime, Trona, etc.) with properly sized sorbent collection system (fabric filter or ESP) would be required upstream of a wet FGD system.

Big Sandy Unit 2, as previously stated, will burn a mid-sulfur fuel, so SO_3/SAM will be present in amounts producing low uncontrolled emissions. However, since Big Sandy Unit 2 has already installed a Selective Catalytic Reduction (SCR) system for NO_x control, the uncontrolled SO_3 emissions are increased since a portion of the SO_2 in the flue gas converts to SO_3 in an SCR. Again, the SO3 concern is mitigated since the dry FGD system is highly effective at removing SO_3.

Hydrochloric (HCl) and Hydrofluoric (HF) Acids

Both wet and dry FGD technologies are capable of achieving low outlet emission rates of HF and HCl.[21] The mechanism of capture is somewhat different for each technology. Dry FGD relies on the reaction of lime with the chlorine and fluorine to form solid particles that are collected in the downstream PJFF, while wet FGD systems rely on the solubility of these particles in the scrubbing liquor for removal. Both wet and dry FGD systems have demonstrated the capability to achieve low outlet emission rates, and both are accepted within the industry as effective and reliable control technology for these pollutants.[22]

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[15] *Id.*

[16] *Id.*

[17] *Id.*

[18] Reference Attachment BS-03 - B&W Steam: Its Generation and Its Use, 41st Edition, 2005, Chapter 35, p. 13.

[19] Reference Attachment BS-08 - Tonn, D. P., et al. B&W. "An Emissions Approach to SO3 Mitigation." Technical Paper BR-1815, Presented at Seventh Power Plant Air Pollutant Control "Mega" Symposium, Baltimore MD, 8/2008, p. 2.

[20] *Id.*, p. 3.

[21] Reference Attachment BS-09 - Carmeuse Natural Chemicals FGD FAQs. http://www.carmeusena.com/page.asp?id=119&langue=EN#5, p. 2.

[22] Reference Attachment BS-10 - Institute of Clean Air Companies (ICAC) – Acid Gas/SO_2 Control Technologies. www.icac.com/i4a/pages/index.cfm?pageid=3401, p. 1.

Waste Effluent

Wet FGD systems produce a chloride purge stream (CPS) that contain concentrations of mercury, selenium, and other heavy metals found in the fuel. Future NPDES permit renewals may pose limits on the discharge of heavy metals at the plant outfalls. Since the dry FGD systems evaporate the water added to the system and collect the dry waste material in the fabric filter, the CPS stream is eliminated and the risk of future NPDES permit compliance relating to the CPS stream is mitigated.

Stack Considerations

Plants with wet FGD systems have what is commonly referred to in the industry as a "wet stack." This means that under all unit operating conditions, and all ambient conditions, a thick water vapor plume is visible exiting the stack. A wet stack must have an internal stack liner constructed of material suited to handle the high moisture content of the exiting flue gas. Typically, wet stack liners are constructed of fiberglass reinforced plastic (FRP), acid-resistant brick, or alloy to prevent corrosion damage.[23] Additionally a wet stack must have a sophisticated liquid collection and drainage system to minimize excessive moisture carryover, otherwise unacceptable amounts of condensed and agglomerated liquid droplets may be discharged from the top of the stack.[24] These additional design considerations add to the overall capital cost of the wet FGD system.

Dry FGD systems operate above the saturation temperature of the flue gas, therefore the plume from the stack is normally not visible, but a slight steam plume may be visible under certain ambient weather conditions (temperature, humidity, etc.). Because the plume is maintained above saturation, the stack following a dry FGD can be constructed of carbon steel. In addition, the dry FGD technology mitigates the risk for wet stack carryover due to any component issues associated with the wet FGD system.

Other Technologies Considered

Within the realm of wet and dry FGD processes, several technologies besides LSFO spray tower wet FGD and dry FGD systems such as NID, CDS, and SDA are being considered for use in the industry, but were determined to be undesirable for use at Big Sandy Unit 2. Other means of flue gas desulfurization considered were:

- Jet Bubbling Reactor Technology (Alstom Flowpac and Chiyoda)
- Advatech Double Contact Flow
- In-duct sorbent injection (Trona, Sodium Bi-carbonate, Hydrated Lime, etc.)

Alstom Flowpac and Black & Veatch Chiyoda

The Alstom Flowpac and Black & Veatch Chiyoda Jet Bubbling Reactor (JBR) processes are similar wet FGD technologies that are designed for high sulfur coal applications. Both technologies achieve SO_2 removal by moving the flue gas through a column of turbulent liquid limestone slurry. As with other wet FGD technologies, these systems exhibit similar collateral energy, environmental, and economic impacts that make them less attractive than dry FGD. In addition, both are relatively new to the U.S. market and there is limited industry experience with respect to performance, reliability and maintenance as compared to spray tower wet FGD systems.

Advatech Double Contact Flow

Double Contact Flow is a wet FGD design developed by Mitsubishi Heavy Industries (MHI). This technology is essentially another variation on the wet spray tower FGD design. The name "Dual Contact"

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[23] Reference Attachment BS-11 - Anderson, David and Maroti, Lewis. "Designing Wet Duct/Stack Systems for Coal-Fired Plants." Power Magazine, March 15, 2006, p. 2

[24] *Id*, p. 1.

is derived from the fact that the flue gas is introduced at the bottom of the absorber vessel and slurry is sprayed upward. As the slurry falls back down in the vessel due to gravity, it re-contacts the flue gas, thus "dual contact." This technology is being used in Japan, and has only been marketed in the U.S. via a joint venture between URS and MHI called Advatech, LLC.[25] The Advatech design is novel, but is still essentially a spray tower wet FGD system, and is subject to the same environmental, energy, and economic concerns previously identified.

In-duct Sorbent Injection

In-duct sorbent injection was considered as a potential means of SO_2 control at Big Sandy Unit 2, but as compared to the performance of a dry FGD and fabric filter system, the technology could not be justified. In-duct sorbent injection may be desirable where high removal efficiencies above 90% are not required. However, when highly efficient results are desired, the in-duct sorbent injection systems cannot match the performance and low O&M costs of the dry FGD system.

NID vs. CDS Discussion

NID and CDS (Circulating Dry Scrubber) technologies are similar in that they are both lime-based dry FGD systems. In addition, both technologies:

- Can achieve high SO_2, SO_3, HAPs, and particulate removal over a broad range of fuels.
- Employ a reactor in conjunction with a Pulse-Jet Fabric Filter (PJFF) to achieve emissions reduction.
- Use either quicklime (CaO) or hydrated lime ($Ca(OH)_2$) reagent and produce landfill byproduct consisting of calcium sulfite/sulfate, ash, and unreacted lime reagent.
- Employ low-cost carbon steel materials of construction.

However, NID FGD technology is selected for use at Big Sandy Unit 2 in lieu of CDS FGD technology because it offers the following advantages:

- **Modular Design:** NID's modular design concept offers a number of benefits. A NID module consists of a reactor (J-duct) with accompanying mixer/hydrator coupled with a dedicated PJFF compartment. Depending on the mixer/hydrator size selected, the individual modules are typically in the 30-90 MW equivalent capacity range. Larger boiler units are accommodated by employing multiple modules in a parallel arrangement. Big Sandy Unit 2 would utilize 12-14 NID modules. Advantages of this approach include:

  Reliability: Each module is equipped with inlet and outlet dampers. Consequently, in a multi-module application, any individual module can be removed from service via the isolation dampers allowing that module to be maintained (i.e. bag change, mixer/hydrator maintenance, etc.) on-line in a safe manner. Big Sandy Unit 2 would be designed to achieve guaranteed emissions at 100% MCR with 1 of the modules out of service. A corresponding CDS would utilize fewer flue gas trains (3 to 4). To achieve the same level of reliability as NID, a CDS system would have to include a spare flue gas train, which would increase the capital cost significantly. Alternatively, a significant de-rate would have to occur to allow for reactor/PJFF maintenance.

  Turn Down: The use of multiple parallel isolatable modules is also a benefit from the standpoint of turn down. Both NID and CDS have limited turn down with respect to an individual flue gas train due to the need to entrain (NID) or suspend (CDS) ash and lime particles. CDS reactors have comparatively less ability to operate at reduced gas flow and must rely on flue gas recirculation in order to suspend the fluidized bed in the reactor. Flue gas recirculation entails significant capital and O&M expense, increases corrosion potential, and complicates operation.

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[25] Reference Attachment BS-12, Mitsubishi Heavy Industries Environmental Systems Product Description, http://www.mitsubishitoday.com/ht/d/sp/i/302/pid/302.

With NID on the other hand, load variations are accommodated by placing modules into and out of service to match the boiler effluent flue gas flow.

Scale-Up: By replicating modules with proven performance characteristics, scale-up risk with NID is minimal. Scale-up of large fluidized bed reactors like those utilized by CDS can be problematic.

- **Footprint:** NID systems are more compact than corresponding CDS systems. CDS systems are similar to Spray Dryer Absorber (SDA) dry FGD systems in that there is a large, cylindrical vessel that must be located upstream of the PJFF. With the NID system, the reactors are close-coupled to the PJFF compartments and fit within a very compact footprint.

- **Arrangement:** NID systems facilitate plant layout and minimize ductwork costs for retrofit applications by having a single inlet and single outlet flue gas duct connection on the same end of the structure. While a CDS system can be designed with the inlet and outlet connections on the same end of the PJFF, ductwork must be routed to the numerous reactor trains and then returned to the stack.

- **Constructability:** In this area, NID has several major advantages over CDS:

  Shop Assembly: NID reactors can be shop-assembled in several large pieces and delivered to the plant via truck. CDS reactors, on the other hand, must be delivered "knocked down" and field erected. The additional man-power, scaffolding, crane costs, etc. associated with erecting the CDS reactors are significant. In addition, with NID, other components such as the day silos and mixer/hydrators can be shop-assembled yielding further construction savings.

  Rectangular Design: Shop fabrication and field assembly of NID reactors is facilitated by the rectangular design as compared to the round configuration of CDS reactors.

  Height: CDS systems are significantly taller than NID systems. This increases construction costs.

- **Integrated Mixer/Hydrator:** With the NID technology, the recycled ash, lime, and water are blended outside the flue gas stream in a simple disc mixer. Crushed lime is prepared in a "backpack" hydrator. All solids are conveyed by gravity. Low-pressure water spray nozzles are used to introduce water into the hydrator and mixer. In contrast, with a CDS system, the lime is prepared in an external hydrator system and then conveyed to an intermediate silo for use in the reactor. Precise control of the hydrator system is difficult, but required, in order to prevent pluggage in the hydrated lime transfer and storage system and maintain proper performance. Flue gas, recycled ash, and hydrated lime enter the fluidized bed reactor through venturi nozzles at the base of the reactor, which is a high wear area and maintenance concern. High pressure water is added directly to the fluidize bed reactor via to maintain the required operation temperature. NID has several advantages in this area:

  External Mixing: As noted above, with NID, the recycled ash, lime, and water are combined in the mixer where (1) good blending can be achieved, and (2) if there is an upset, any deposits will be outside the flue gas stream and confined to the mixer, which can be maintained on-line by isolating the affected module. With CDS, water is sprayed directly into the large fluidized bed reactor separate from the alkali. With this approach, it is difficult to achieve good mixing of the water, ash, and lime, and if there is an upset or poor mixing, deposition will occur in the reactor necessitating a reactor shut-down for cleaning. In addition, miss application or component failures of the water spray system will result in wetting of and subsequent damage to the coated fabric filter bags in the PJFF. Also, due to the external mixing of water and ash, NID systems are able to operate at lower approach temperatures than CDS systems. This reduces lime consumption without increasing risk of corrosion and/or deposition.

Simplicity: The NID "backpack" hydrator is a very simple, compact, single-stage device. In contrast, with CDS, crushed lime is treated in the hydrator, transferred to and stored in a surge bin/silo, and then transferred to the reactor.

- **Technology Ownership:** Alstom developed the NID technology in-house and has 100% ownership of the patents, intellectual property, and product know-how. All US CDS suppliers operate under a license agreement acquired from one of several a European entities. Further, some US CDS suppliers employ 3rd party PJFF's. Single point accountability for the technology and project execution reduces risk to AEP and facilitates resolution of any future contractual or performance issues.

- **Competitive Capital Cost:** Based on a request for Budgetary Cost Estimate solicited by AEP to Alstom (NID), Babcock Power (CDS), and B&W (CDS), the Alstom NID is competitively priced. The budgetary cost estimate for the Alstom NID was [redacted] compared to [redacted] for the Babcock Power CDS. The budgetary cost estimate for the B&W CDS system was [redacted] but their proposal did not account for several scope items, including 100% emergency bypass duct and damper for each CDS train and clean gas recirculation duct and damper. Further, B&W or their licensee has never installed a CDS system to date, so the decision was made to exclude the budgetary cost estimate for the B&W CDS system from this evaluation.

APPENDIX

Parameter	NID FF	SDA FF	CDS FF	WFGD & WESP	Notes
Uncontrolled Inlet SO_2 (lb/mmbtu)	4.5		4.5	4.5	NID FF, WFGD and WFGD&WESP Assumes 2.69% sulfur and 12,490 Btu/lb HHV. SDA FF assumes 1.81% sulfur and 12007 btu/lb HHV. For the SDA FF System, using a 3.0 lb/mmBtu SO2 fuel is the maximum fuel the SDA FF System can handle and still maintain a guarantee of 95% SO2 removal efficiency.
Outlet SO_2 lb/mmbtu	0.09		0.09	0.09	Based on 98% SO2 Removal efficiency for NID FF/ CDSFF, WFGD and WFGD&WESP
SO2 Removal Efficiency (%)	98		98	98	
Annual Water Consumption (MGY)	572		569	624	Calculated on the basis of 85% capacity factor
Water Consumption (GPM)	1280		1,274	1397	Water Consumptions based on S&L Order-of-Magnitude FGD Cost Estimate Dated 10/14/2010 Project # 12721-000 for Big Sandy Unit 2
Annual Aux Power usage (MWh)	111,690		119,136	230,826	Calculated on the basis of 85% capacity factor and 8760 hrs/yr
Aux Power (MW)	15		16	31	Based on S&L Order-of-Magnitude FGD Cost Estimate Dated 10/14/2010 Project #12721-000 for Big Sandy Unit 2
Annual Reagent Usage (TPY)	216,980		223,380	236,351	Calculated on the basis of 85% capacity factor and 8760 hrs/yr.
Reagent Usage (lb/hr)	58,281		60,000	63,484	Based on S&L Order-of-Magnitude FGD Cost Estimate Dated 10/14/2010 Project #12721-000 for Big Sandy Unit 2. Note that The DFGD uses Lime as its reagent and the WFGD uses Limestone as it's reagent. The cost savings of using limestone is captured is the O&M cost comparision section below.
Total Solid Waste Production (TPY)	634,034		640,356	643,446	Total Solid Waste Production is Annual Byproduct production (TPY) + Annual Flyash Production (TPY).
FGD Byproduct Production (lb/hr)	170,302		172,000	121,012	Based on S&L Order-of-Magnitude FGD Cost Estimate Dated 10/14/2010 Project #12721-000 for Big Sandy Unit 2. Flyash loading is limited to .1 lb/mmbtu (max particulate loading) in the WFGD options because of Aluminum-Fluoride blinding concerns. It should be noted for the DFGD options the ESP is out of service and all the flyash is collected in the FF.
Annual Byproduct Waste Production (TPY)	634,034		640,356	450,528	Calculated on the basis of 85% capacity factor and 8760 hrs/yr. The NID and SDA Option included the full loading of Flyash. Flyash loading .1 lb/mmbtu (max particulate loading) in the WFGD options because of Aluminum-Fluoride blinding concerns. It should be noted for the DFGD options the ESP is out of service and all the flyash is collected in the FF.
Annual Flyash Production (TPY)	0		0	192,918	Calculated on the basis of 85% capacity factor and 8760 hrs/yr. It should also be noted that the ESP's are still in service for both WFGD options and that flyash will still need to be disposed of. This will add 51,818 lb/hr flyash to the WFGD's Total Waste Production. It should be noted for the DFGD options the ESP is out of service and all the flyash is collected in the FF.
Equipment Footprint (acres)	3.52		3.54	4.56	Acres based on general arrangement site plans for major equipment for each FGD System.
Technology that best supports ACI (Mercury Removal)					ACI works best with a FF/baghouse. However, this is plant specific. You can install ACI up stream of an ESP and use the ESP to collect the ACI material. You will not be able to sale the ash though. You can remove oxidized mercury in a WFGD but their are re-emission concerns that are not well understood at this time.
Technology that best supports SO3 removal					Spray towers have a 20% reduction guarantee, JBR's have a 40% reduction guarantee and Alstoms DFGD has a less then or equal to 1ppm guarantee. No WFGD can remove SO3 down to this level. Lime is a better at Capturing SO3.
Technology that best supports other hazardous air pollutants (HAP's)					For HCL, technologies are equal (no winner). Most of the Power Industry looking to install FF/Baghouses for HAPS control.
Technology that best supports future plant outfall regulations					No heavy metals purge stream needed for a DFGD System.

Indicates which Technology is favored
Indicates SDA/FF doesn't meet 4.5 lbSO2/mmbtu design basis @ 98% removal Efficiency

Kentucky Power Company

REQUEST

Refer to page 16 of the Walton Testimony, lines 21-22, which supports the position that a wet FGD is less capital intensive than a dry FGD. Provide a comparison of the operation and maintenance costs of the two FGD processes.

RESPONSE

Page 16 of the Walton Testimony, supports the position that a dry FGD is less capital intensive as compared to a wet FGD.

Please see Commission Staff's First Set of Data Requests, Item No. 30, Attachment 1, page 9 for a comparison of operation and maintenance costs for the two FGD processes.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to the Walton Testimony, page 17, line 22, to page 18, line 10. Provide the projected in-service cost of the equipment listed.

RESPONSE

The projected breakdown of the in-service cost estimate for the specific equipment listed will be developed as a part of the overall scope of the Phase I activities.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 19 of the Walton Testimony, lines 9-12, which indicates that the Class 4 estimate for the dry FGD installation is -15 percent to +20 percent of the $839 million estimate. What confidence level, in terms of probability, has Kentucky Power and/or AEP associated with this estimate range?

RESPONSE

Kentucky Power and AEP have a high level of confidence in the estimate range based upon past experience, but tempered by the lack of site-specific project definition. A detailed risk analysis will be conducted during Phase I to validate the current estimated cost range and establish a level of confidence in terms of probability.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 19 of the Walton Testimony, line 17. Clarify whether the 20 percent contingency is included in the $839 million estimate.

RESPONSE

Yes, the 20 percent contingency is included in the $839 million estimate.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 21 of the Walton Testimony, lines 10-14. It states that the NID dry FGD technology has been installed on 1,800 MW of capacity in the US.

a. Identify the units equipped with this technology and their locations.

b. Describe the "due diligence" that AEP performed with regard to the dry FGD technology and provide a copy of the due diligence report.

RESPONSE

a.

Plant	Unit	MW	Location
Seward	1a	292.5	East Wheatfield, PA
Seward	1b	292.5	East Wheatfield, PA
Gilbert	3	300	Maysville, KY
Spurloack	4	300	Maysville, KY
Indian River	3	175	Millsboro, DE
Indian River	4	440	Millsboro, DE

b. Please see Attachment 1 to this response.

WITNESS: Robert L Walton

AMERICAN
ELECTRIC
POWER

Date September 17, 2010

Subject **Big Sandy Unit 2 FGD –**
NID & IAQCS Technology Due Diligence Review

From G. M. Gibbs – Manager, FGD Program Engineering

To T. V. Riordan – VP, Engineering Services
M. J. Finissi – VP, Project Management & Construction
W. L. Sigmon – SVP, EP&FS

On September 10, 2010, personnel from Projects and Engineering Services participated in a high level technology due diligence review of the NID and Integrated Air Quality Control System (IAQCS) technologies being considered for the Big Sandy Unit 2 FGD technology selection. The "Technology Due Diligence Team" was comprised of the following:

Dan Drew – Director, Project & FGD Program Engineering
Dave McCammon – Director, Electrical Engineering
Mike Durner – Director, Mechanical Engineering
Tim Riordan – Vice President, Engineering Services
Tom Hart – Manager, FGD Systems & Chemical Engineering
Greg Gibbs – Manager, FGD Program Engineering
Jim Zucal – Project Manager, Big Sandy Unit 2 FGD
Mike Bright – Project Director, Big Sandy Unit 2 FGD
Chris Beam – Director, Environmental Retrofits

The purpose of this technology due diligence review was to address the following concern among EP&FS leadership: What is AEP's plan to address "first time evolution" concerns with the NID and IAQCS technologies? It should be noted that this technology due diligence review need was initially socialized by Mike Finissi in a Projects staff meeting where Engineering Services took an action to develop a review process and plan. As a result, the 9/10 working meeting was conducted to finalize the high level risk assessment for the NID and IAQCS technologies and provide consensus on answers to the following questions:

1. Are there any technical risk show stoppers (i.e. fatal flaws) that would exclude the NID or IAQCS technologies as viable options for the Big Sandy Unit 2 FGD technology selection?
2. Are there any technical risk concerns associated with the NID or IAQCS technologies that need addressed before making the Big Sandy Unit 2 FGD technology recommendation to AEP Senior Management?
3. What are the technical risk concerns associated with the NID or IAQCS technologies that need addressed during the conceptual design phase of the Big Sandy Unit 2 FGD project,

including the appropriate next steps to disposition the identified risks (Critical Business Reviews (CBRs), formal Design Review Meetings, etc.)?

Technology Due Diligence Review Conclusion

Based on the Technology Due Diligence Team's high level risk assessment, there are no identified technical risk show stoppers that would exclude the NID or IAQCS technologies as viable options for the Big Sandy Unit 2 FGD technology selection. Further, there are no identified technical risk concerns that warrant disposition before making the Big Sandy Unit 2 FGD technology recommendation to AEP Senior Management. All identified technical risk concerns should be dispositioned during the conceptual design phase of the project via the Design Review Process (including technical due diligence CBRs) as identified in the High Level Risk Assessment Summaries below.

Technology Due Diligence Review Methodology

Risk concerns relating to the NID technology were generated from the following investigations:

- NID 101 presentation by Alstom in early January 2010
- Trip to the Spurlock Generating Station in Maysville, KY in early May 2010
- NID technical presentation by Alstom in late May 2010
- AEP review of Alstom drawing package (P&IDs, General Arrangements, System Descriptions, and major component detail drawings) of typical 8 module NID design.

Risk concerns relating to the IAQCS technology were generated from the following investigations:

- IAQCS 101 presentation by Alstom in early January 2010
- AEP review of Alstom drawing package (P&IDs, General Arrangements, System Descriptions, and major component detail drawings) of applicable IAQCS design.

Note the IAQCS technology is essentially the blending of wet FGD (spray tower) and dry FGD (SDA/fabric filter) technologies, both of which AEP are very familiar. As such, AEP's high level risk assessment focused on the subsystem that introduces the wet FGD chloride purge stream into the dry FGD system.

Using the aforementioned investigations as a basis, FGD Program Engineering developed preliminary High Level Risk Assessments for the NID and IAQCS technologies. These preliminary High Level Risk Assessments were then reviewed and amended by the Technology Due Diligence Team during the 9/10 meeting, and finalized as documented in this memorandum.

High Level Risk Assessment Summaries (Final)

Several risk concerns identified in the preliminary High Level Risk Assessments were reclassified as "design details" by the Technology Due Diligence Team. As a result, there is a High Level Risk Assessment for each technology identifying the risk concerns and associated review disposition, and separate tables documenting design concerns to be addressed via the AEP Design Review Process and AEP OEM Procurement Specification for the FGD System.

NID High Level Risk Assessment

High Level Risk Assessment for Alstom NID Technology					
Big Sandy Unit 2 FGD Technology Due Diligence Team, 9/10/2010					
Item No.	Detailed Risk Item Description	Qualitative Risk Analysis			Review Disposition
		Prob	Impact	Severity	
1	No "directly applicable" (with respect to ash loading, SO2 removal, and fresh lime usage with the NID modular configuration) commercial installation of NID for AEP to visit and mitigate "first time evolution" concerns.	High	High	High	Technology Due Diligence Review
2	Layout of ash and/or plugging of inlet plenum and ductwork feeding the multiple NID reactors, especially at lower loads with modules out of service. Also, plugging of the reverse goose necks upstream of the NID reactors upon unit upset (such as ID fan trip) that would cut off purge gas path.	Low	High	Medium	CBR (Conceptual Design Phase)
3	NID Mixer Concern: It appears the fresh lime/recycled fly ash & calcium material mixture merely overflows into the gas path, all by gravity. This method does not seem to provide an active control of the mixture flow and distribution. Modeling of the flow of the mixture onto the dispersion plate and into the gas path is certainly required. Has any modeling or testing been performed on the mixer to show distribution of material into the reactor duct? What modeling or testing has been performed to show that there is equal distribution along the dispersion plate?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
4	NID Mixer Concern: With the given mixing rotation, it appears that there would be uneven mixing between the material pulled toward the mixer exit (less mixing), and the material that is recirculated around the rear disc shaft. What modeling or testing has been performed to verify product exiting the mixer is uniformly mixed?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
5	Hydrator Concern: How does Alstom mitigate pluggage and scaling concerns? What is the hydrator operating temperature? How was the hydrator sized to ensure appropriate "slaking"?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
6	J Duct/Reactor Concern: At 300°F plus inlet temperature and heavy dust load, is AR steel plate the right material to address erosion concerns for the Big Sandy Unit 2 application? Through what other design means have erosion concerns been addressed? What modeling or testing has been performed to address erosion concerns? Is Spurlock Unit 3 & 4 a representative example of the erosion potential we may see at Big Sandy Unit 2? How does the particle loading from the Spurlock Unit 3 & 4 CFB outlet compare	High	High	High	CBR (Conceptual Design Phase)

	to the particle loading at the Big Sandy Unit 2 ESP inlet?				
7	J Duct/Reactor Concern: AEP requests a more detailed drawing of the dispersion plate and its location in elevation. What pressure drop results from this plate? Has there been any history of build-up problems at the dispersion plate? What modeling or testing has been performed to confirm there is adequate reagent/flue gas mixing at the dispersion plate and downstream in the duct considering the 1-2 second residence time? What is the design split of SO2 removal between the reactor and fabric filter?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
8	J Duct/Reactor Concern: The guide vanes at the exit of the reactor duct look like an area of high wear potential due to erosion, and potential gas path restriction due to plugging. What has been the maintenance experience in this area? What design considerations, if any, have been applied to this area, such as modularized guide vane assembly that can be easily removed and replaced?	High	High	High	CBR (Conceptual Design Phase)
9	Hopper/Fluidized Trough Concern: Is the entire mechanism for ash transfer based on air fluidization and gravity? If fluidization is stopped for any reason, how quickly does it need to be restarted for the extraction flow to be restarted successfully? Is there a required permissive on gas temperature/fluidized trough temperature that would impact a hot restart or turndown scenario (in other words, is there some heat-up delay required for the fluidized trough in response to a system start or turndown)?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
10	Hopper/Fluidized Trough Concern: Is there an ash seeding required for the fluidized trough after every maintenance outage? If so, is there a mechanism for loading the fluidized trough with ash?	Medium	Medium	Medium	CBR (Conceptual Design Phase)
11	NID Control Loop Concerns: From pg 27 in the Functional Control Description provided by Alstom, why is soot blowing impacting the NID outlet temperature? From pg 28 in the Functional Control Description provided by Alstom, what is the technical reason for the minimum control output value of 12% on the NID SO2 controller?	Medium	Medium	Medium	CBR (Conceptual Design Phase)

NID Design Details

Design Concerns for Alstom NID Technology			
Item No.	Component/System	Issue/Concern to Address	Review Disposition
1	Mixer	How is the hydrator/mixer attached to the reactor duct? Is it hard attached, or is there an expansion joint?	Drawing/Document Review

2	Mixer	Does mixer air isolation valve stay open with water spray in use? System Description reads as if this valve is only open a short duration. Wouldn't this valve need to be open the entire time the water spray is off?	Drawing/Document Review
3	Mixer	What is the material of construction and hardness of the scrapers and paddles?	Drawing/Document Review
4	Mixer	How is alarm feedback provided for a failed mixer? From AEP's slaker experience, a speed switch on the outboard end should be included to alarm for failure of the drive or linked shaft or motor/shaft connection where the motor stays running but the mixer does not.	Drawing/Document Review
5	Hydrator	How do the spray nozzles work during the lime hydrating process (continuous vs. intermittent)?	Drawing/Document Review
6	Hydrator	What is the material of construction and hardness of the cover and paddles?	Drawing/Document Review
7	J Duct/Reactor	What are the gas velocities after the dispersion plate? What is the duct material?	Drawing/Document Review
8	Rotary Feeder	Considering the "dust" material handled by the rotary feeders, do the rotary feeders use seal air to protect bearings from dust and failure? Hydrator and mixer both have fluidizing air on shaft seals, but no mention of this on rotary feeders.	Drawing/Document Review
9	Hopper/Fluidized Trough	A more detailed drawing of the fluidized trough design is needed. What is Alstom's history with the fabric becoming plugged such that ash removal is stopped? How is the flow of ash controlled?	Drawing/Document Review
10	Hopper/Fluidized Trough	What is the maximum amount of ash the hopper can hold structurally, related in ash height?	Drawing/Document Review
11	Hopper/Fluidized Trough	A more detailed drawing of the hopper is required to understand how the flow of ash to the mixer is split off from the remaining flow to ash removal.	Drawing/Document Review
12	NID Gas Path	"Double Block and Bleed" capability is required for employees to access out of service NID modules. Double louver dampers or guillotine dampers on the NID inlet will be required for man safe work.	AEP OEM FGD Procurement Spec
13	NID Gas Path	Fabric Filter bypass required for boiler purge provision in the event of a "black plant" trip.	AEP OEM FGD Procurement Spec
14	NID Gas Path	There are no permissives/interlocks to close a given J reactor inlet damper or fabric filter outlet damper. Should there be a permissive/interlock to prevent closing all inlet or outlet dampers at the same time (in order to keep an open flue gas path at all times)?	Drawing/Document Review
15	NID Reactor Grit Conveyor and Feeder	Does the grit conveyor run continuously when the reactor is in service, or is it time cycled? How much grit is carried out per hour? Any maintenance history of grit conveyor erosion based on location in J duct? Has history shown that the grit conveyor can effectively remove ash build-up to preclude flow restriction?	Drawing/Document Review

IAQCS High Level Risk Assessment

No risk concerns were identified by the Technology Due Diligence Team during the 9/10/2010 meeting.

IAQCS Design Details

Design Concerns for Alstom IAQCS Technology

Item No.	Component/System	Issue/Concern to Address	Review Disposition
1	Pre-mix Tank	What are the materials of construction for the premix tank and downstream pumps and piping? If these are carbon steel, what is the highest level of chlorides that will allow the carbon steel material?	Drawing/Document Review
2	Fabric Filter	AEP was only considering a single fabric filter for the West Fleet DFGD Projects, whereas Duke Cliffside Unit 6 utilizes two fabric filters. What are the advantages and disadvantages of one fabric filter compared to two fabric filters?	AEP OEM FGD Procurement Spec
3	Recycle Silo	No recycle silo was shown on the PFD for Duke Cliffside Unit 6. Why no recycle system on an IAQCS considering a recycle system is used with DFGD?	AEP OEM FGD Procurement Spec

If there are any questions or additional clarification needed on any of the above, please advise.

cc: D. H. Drew
D. A. McCammon
M. W. Durner
T. L. Hart
J. E. Zucal
M. L. Bright
C. T. Beam
T. Thomas
A. M. Sink
J. G. Burton
FGD Program Engineering

Kentucky Power Company

REQUEST

Refer to page 22 of the Walton Testimony, lines 15-17. It states that the wet FGD at Big Sandy Unit 2 was abandoned due to increases in the cost estimate "primarily attributed to increases in labor and material costs" despite AEP's efforts to mitigate this risk. Given the expected increase in demand for the installation of environmental compliance equipment in the industry in the upcoming years, explain thoroughly how Kentucky Power can be confident that a similar scenario will not occur.

RESPONSE

KPCo anticipates that a similar scenario could occur and has factored this potential scenario into both our cost estimate and via the addition of the 20% contingency factor.

During the 5-year period 2006 through 2010, the IHS CERA Cost Index data for FGD projects indicate an overall total escalation in costs of 28%, which equates to a 5.1% annual rate. It is KPCo's opinion that utility industry FGDs, SCRs and other environmental projects will experience a similar "boom-bust" cycle as seen in the later part of the last decade and has utilized this 5.1% escalation rate in the estimate.

To further mitigate this potential risk, KPCo also plans to leverage first mover advantages in the marketplace and employ duplication of engineered systems and equipment to the maximum extent possible across the fleet to allow for cost savings associated with bulk purchasing discounts as well as savings associated with maintaining and sharing common spare parts.

Witness Walton specifically addresses this risk in his testimony on page 20, lines 5 to 23 and page 21, lines 1 and 2.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 22 of the Walton Testimony, lines 22-23. It states that there was a decrease in the projected price spread between low and high sulfur coal that effectively eliminated any cost savings associated with using a higher sulfur coal. Provide those price projections.

RESPONSE

In July, 2005, the differential fuel prices between high sulfur and low sulfur coal were projected to yield a savings of $0.15/mmBTU. By March, 2006, the price of the high sulfur versus low sulfur coal had converged to the point that there was no longer any appreciable savings.

Please see page 2 of this response for the projected fuel costs.

WITNESS: Robert L Walton

Big Sandy 2 Projected Delivered Fuel Costs - ($/MMBtu)

Fuel Forecast Date		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Low Sulfur Fuel	$2.22	$2.20	$2.09	$2.06	$2.02	$2.07	$2.11	$2.15	$2.20	$2.24	$2.29	$2.33	$2.38	$2.43	$2.47
Mar-06	High Sulfur Fuel	$2.09	$2.15	$2.20	$2.21	$2.27	$2.32	$2.37	$2.42	$2.48	$2.53	$2.59	$2.64	$2.70	$2.76	$2.81
	Fuel Spread					$ 0.24										
	Low Sulfur Fuel	$ 2.46	$ 2.29	$ 2.17	$ 2.08	$ 2.08	$ 2.12	$ 2.16	$ 2.19	$ 2.23	$ 2.26	$ 2.30	$ 2.34	$ 2.37	$ 2.41	$ 2.45
Jul-05	High Sulfur Fuel	$ 1.91	$ 1.96	$ 1.85	$ 1.89	$ 1.93	$ 1.97	$ 2.01	$ 2.05	$ 2.09	$ 2.13	$ 2.18	$ 2.22	$ 2.26	$ 2.31	$ 2.35
	Fuel Spread					$ (0.15)										

Kentucky Power Company

REQUEST

Refer to Exhibit RLW-1, which indicates that the Title V Air Review and Approval will take 12 months. The McManus Testimony at page 17, lines 10-12, states that issuance of the air permit will take up to 18 months from the date of application. Clarify the divergence in time estimates.

RESPONSE

Please see the response to Item No. 9 of this set of data requests.

WITNESS: Robert L Walton

Provide the following operational information for Big Sandy Units 1 and 2:

a. The number of normal cycles (stops and starts).

	Unit 1	Unit 2
2007	1/1	1/1
2008	4/4	3/3
2009	11/11	4/4
2010	2/2	0/0
2011	3/2	2/2

b. The number of emergency trips and starts.

	Unit 1	Unit 2
2007	4/4	3/3
2008	7/7	3/3
2009	3/3	5/5
2010	0/0	5/5
2011	0/0	4/4

c. Capacity Factor for the last five years.

	Unit 1 (%)	Unit 2 (%)
2007	74.69	83.22
2008	54.99	67.81
2009	58.75	70.26
2010	36.41	80.98
2011	77.31	65.07

Note – 2011 is November YTD

d. Heat Rate for the last five years.

	Unit 1 (Btu/kWH)	Unit 2 (Btu/kWH)
[redacted]	[redacted]	[redacted]

Note – 2011 is November YTD

e. Major internal and minor outages including the major projects completed during each outage for the last 10 years.

Note – does include forced outage (FO) events

2002

Unit 1

Type	Repairs	Dates
PO	BOILER OVERHAUL	03/23/02-05/20/02
MO	TURBINE OVERSPEED TRIP TEST	05/20/02-05/21/02
MO	DEAERATOR	05/31/02-06/02/02
PO	TURBINE GENERATOR VIBRATION	11/07/02-11/08/02
MO	TURBINE GENERATOR VIBRATION	11/08/02-11/08/02
MO	TURBINE GENERATOR VIBRATION	11/22/02-11/23/02

Unit 2

Type	Repairs	Dates
PO	BOILER OVERHAUL	09/13/02-12/29/02
PO	TURBINE GENERATOR VIBRATION	12/29/02-12/29/02
PO	TURBINE OVERSPEED TRIP TEST	12/30/02-12/30/02

2003

Unit 1

Type	Repairs	Dates

Unit 2

Type	Repairs	Dates
PO	PLANT MODS STRICTLY FOR COMPLIANCE	04/12/20-05/03/03
MO	FEEDWATER PUMP DRIVE - STEAM TURBINE	10/03/03-10/13/03

2004

Unit 1

Type	Repairs	Dates

PO BOILER	OVERHAUL	04/02/04-04/18/04
MO TURBINE	GENERATOR VIBRATION	04/22/04-04/25/04

Unit 2

Type	Repairs	Dates
PO	BOILER OVERHAUL	03/06/04-03/22/04
MO	CONTROL VALVES	07/15/04-07/18/04
PO TURBINE	GENERATOR VIBRATION	11/13/04-11/25/04
PO	TURBINE OVERSPEED TRIP TEST	11/26/04-11/26/04
PO BOILER	COMBUSTION/STEAM CONTROLS	11/26/04-11/26/04
PO	BOILER FEEDWATER CONTROLS	11/26/04-11/26/04

2005

Unit 1

Type	Repairs	Dates
PO	Major turbine overhaul	04/30/05-06/04/05
PO	Overspeeds & Balance shot Major turbine overhaul	06/04/05-06/05/05

Unit 2

Type	Repairs	Dates

2006

Unit 1

Type	Repairs	Dates
PO	Inspection	09/30/06-10/08/06

Unit 2

Type	Repairs	Dates
PO	Minor boiler overhaul	04/29/06-05/22/06
MO	Repair economizer tube leak	07/07/06-07/09/06

2007

Unit 1

Type	Repairs	Dates
PO	Minor boiler overhaul	04/14/07-04/29/07
PO	Repair T-1 turbine bearing	04/29/07-05/05/07
PO	Balance Shot Vibration of the turbine generator	05/05/07-05/05/07

Unit 2

Type	Repairs	Dates
PO	Minor boiler overhaul	04/28/07-05/13/07

2008

Unit 1

Type	Repairs	Dates
MO	Tube Leak Waterwall (Furnace wall)	02/16/08-02 /17/08
MO	Burner / Precipitator Repairs	05/24/08-05/26/08
MO	Cyclic Stress Test Boiler performance testing	09/13/08-09/14/08
PO	Major turbine overhaul	09/19/08-12/16/08
MO	FPT Strainer and Casing Leak Repair	12/24/08-12/27/08

Unit 2

Type	Repairs	Dates
PO	Major boiler overhaul	04/26/08-06/08/08
MO	Main Turbine Bearing Repairs	08/08/08-08/19/2008
MO	Tube Leak Repair Waterwall (Furnace wall)	11/27/08-12/01/2008

2009

Unit 1

Type	Repairs	Dates
MO	Strainer replacement on Turbine;Precip repairs	02/17/09-02/19/09
PO	Turbine strainers; Intercept valves	05/28/09-06/01/09
MO	MO 16 Repair HP Extraction steam valves	06/12/09-06/14/09
MO	Aux feedpump repairs	07/02/09-07/04/09
MO	Valve Repair feedwater valves	07/21/09-07/22/09
MO	Change out check valve on aux. feedpump	07/23/09-07/24/09
MO	Repair oil cooler leak, 2 steam leaks and clean breakers	08/29/09-09/01/09
MO	Repair Burner Tips	09/01/09-09/07/09
MO	Repair oil leak in the cooling water system	09/26/09-10/02/09
MO	Burner Spreaders + Valve Work	10/05/09-10/08/09

MO Precipitator Work 11/13/09-11/17/09

Unit 2

Type	Repairs	Dates
PO	Steam Seal Modification + AH Wash	05/22/09-05/26/09
MO	Air Heater / Condenser Exp. Joint	07/07/09-07/11/09
MO	Boiler Inspection/AH Wash	09/02/09-09/11/09
MO	Air Heater Soot Blower	09/11/09-09/12/09
MO	Precip work; Other stack or exhaust emissions testing	12/06/09-12/08/09
PO	Stand Alone Stack Testing on Unit 1	12/08/09-12/10/09

2010

Unit 1

Type	Repairs	Dates
PO	Major boiler overhaul	02/27/10-06/12/10
PO	Boiler	09/11/10-12/15/10

Unit 2

Type	Repairs	Dates
PO	Minor boiler overhaul	05/01/10-05/15/10

2011

Unit 1

Type	Repairs	Dates
MO	Precip inspection	06/11/11-06/14/11
MO	Waterwall Tube Leak (Furnace wall)	08/05/11-08/10/11

Unit 2

Type	Repairs	Dates
MO	Clean and repair air heaters	03/15/11-03/18/11
MO	Boiler inspection and casing leak repairs	08/30/11-09/06/11
MO	Misc boiler, air heater and casing leak repairs	09/07/11-09/09/11
MO	Miscellaneous boiler repairs	09/28/11-10/07/11
MO	Casing leaks repairs and other misc repairs	10/12/11-10/16/11
MO	Casing Leak repairs	11/20/11-12/02/11

f. An outline of the major availability and performance detractors for the last five years.

	Unit 1		Unit 2	
	EFOR (%)	**EA (%)**	**EFOR (%)**	**EA (%)**
2007	5.31	87.44	4.19	90.69
2008	13.24	62.45	7.16	77.12
2009	9.55	81.97	4.14	89.00
2010	5.66	39.42	5.10	88.17
2011	5.34	89.58	12.89	76.68

Note – 2011 is November YTD

Major detractors

Year / EFOR Category **EFOR (%)**

2007
Unit 1
First Superheater 1.954
Second Superheater 1.148
Waterwall (furnace) 0.588

Unit 2
Other lube oil system problems 1.774
Waterwall (furnace) 1.334
Burners 0.340

2008
Unit 1
Particulate stack emissions 3.975
Second superheater 2.285
Opacity 1.864

Unit 2
Economizer 3.716
Opacity 0.826
Steam turbine control upgrade 0.719

2009
Unit 1

Particulate stack emissions	5.679
4000-6000 volt circuit breakers	1.917
Waterwall (furnace)	0.773

Unit 2

Opacity	1.3
Gland seal system	0.877
Air heater (regenerative)	0.505

2010

Unit 1

Forced draft fan lubrication system	3.982
Primary air fan	0.219
Igniters	0.209

Unit 2

Economizer	1.634
Deaerator (including level control)	1.296
Other pulverizer problems	0.306

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Dated January 13, 2012
Item No. 39
Attachment 2
Page 1 of 1

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Kentucky Power Company

REQUEST

Recognizing that AEP has no experience with installing the proposed NID dry FGD technology, describe how confident it is with the accuracy of the cost and schedule estimates.

RESPONSE

Kentucky Power and AEP have a high level of confidence in the estimate range based upon past experience, but tempered by the lack of site-specific project definition. As stated on page 19, lines 9-12, of the Walton testimony, the Class 4 estimate for the NID FGD is considered accurate to within -15 percent to +20 percent.

It should be noted that, although, the proposed NID system is a unique arrangement, it consists of components such as mechanical equipment, ductwork and baghouses that are commonly used throughout the utility industry and of which AEP has installation experience.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Explain the difference in the in-service date on the Walton Testimony, page 19, line 2, of the second quarter of 2016, and the December 2015 date in the Application, at paragraph 12, page 6.

RESPONSE

The December 2015 date in the application references the date an FGD must be placed in-service as set forth by the Consent Decree for Big Sandy Unit 2 to run. The unit will be idled until the in-service date for this project, which is projected to be in the second quarter of 2016.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Explain whether Kentucky Power intends to manage the Big Sandy Unit 2 dry FGD project on a multi-prime basis or Engineering, Procurement and Construction basis.

RESPONSE

Kentucky Power intends to manage the Big Sandy 2 DFGD project on a multi-prime basis.

WITNESS: Robert L Walton

Kentucky Power Company

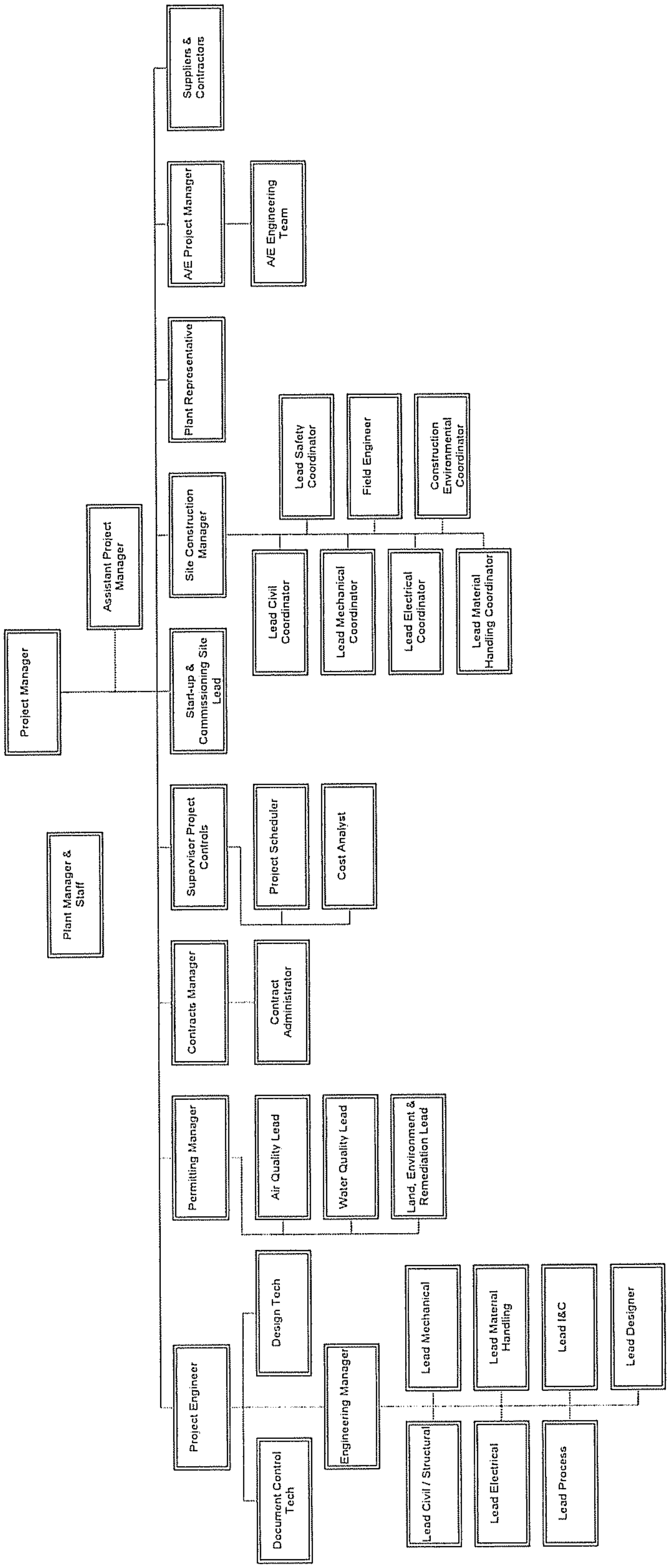
REQUEST

Provide an organization chart of the AEPSC construction management team that will be managing the proposed dry FGD project.

RESPONSE

Please see Page 2 of this response for an organizational chart for a typical project management team.

WITNESS: Robert L Walton


Plant Manager & Staff
Project Manager
Assistant Project Manager
Project Engineer
Design Tech
Document Control Tech
Engineering Manager
Lead Mechanical
Lead Material Handling
Lead I&C
Lead Designer
Lead Civil / Structural
Lead Electrical
Lead Process
Permitting Manager
Air Quality Lead
Water Quality Lead
Land, Environment & Remediation Lead
Contracts Manager
Contract Administrator
Supervisor Project Controls
Project Scheduler
Cost Analyst
Start-up & Commissioning Site Lead
Site Construction Manager
Lead Safety Coordinator
Field Engineer
Construction Environmental Coordinator
Lead Civil Coordinator
Lead Mechanical Coordinator
Lead Electrical Coordinator
Lead Material Handling Coordinator
Plant Representative
A/E Project Manager
A/E Engineering Team
Suppliers & Contractors

Kentucky Power Company

REQUEST

Describe Kentucky Power's plans for retiring and decommissioning Big Sandy Unit 1. Will the unit be demolished or will the structure and selected components be reutilized as a natural gas fired combined cycle unit.

RESPONSE

The current plan is to retire Big Sandy Unit 1. Kentucky Power Company continues to evaluate other alternatives including refueling to replace the capacity from this unit. The Company will develop plans for retiring or decommissioning the unit.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Explain whether Kentucky Power plans to use Electro-Static Precipitators ("ESP") with the NID technology. If the ESP is eliminated, what is the resultant reduction in station service load?

RESPONSE

KPCo does not plan to use the ESPs with the NID technology, resulting in an approximate 2 MW savings in auxiliary power at full load. This savings will help offset the increase in station service load resulting from the installation of the scrubber system.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Based on the January 5, 2012 Conference, what is the expected impact of coal blending on the steam generator, air heaters, and SCR system?

RESPONSE

The use of a 4.5 SO2 lb/mmBTU coal blend represents a significant change from the current fuel. In order to maintain reliability and satisfactory operation, the unit will require modifications as outlined below:

1) Balanced Draft Modifications - The design of the Big Sandy Unit 2 steam generator has inherent weaknesses which can allow boiler gases to escape into the surrounding areas. The resultant boiler gases generated when burning higher sulfur coals are even more irritable. This conversion not only improves the working environment, it also improves equipment reliability by reducing ambient temperatures and lowering fugitive dust.

2) Furnace Arch Addition - The Big Sandy Unit 2 steam generator does not have a furnace arch. Higher sulfur fuels generate a greater amount of tenacious slag and adding an arch will improve the ability to maintain furnace cleanliness and thus boiler efficiency by improving gas flow distribution across the superheater surface. This addition has proven extremely successful on the "sister" 800 MW units (Amos Units 1&2 and Mitchell Units 1&2).

3) Low NOx Burners - The existing low NOx burners in place at Big Sandy 2 were designed to reduce NOx emissions by utilization of staged combustion techniques. Slag control in the combustion process is a secondary consideration when burning lower sulfur coal. Recent experience with relatively minimal increases in fuel SO2 content have led to hot burners (a safety concern) and increases in slag formation. The state of the art for Low NOx Burner technology has advanced significantly since the current burners were installed and their replacement is required to accommodate the expanded fuel sulfur range.

4) Additional furnace slag control devices – The use of NAPP coal in the blend will increase slag production in the lower furnace due to the increase in iron content. Illinois Basin coals contain even higher amounts of iron, generating even more slag. The current technology for furnace slag control, water cannons and hydro jets, has proven successful in addressing this issue.

5) Additional superheater slag blowers - Currently, the leading edge of the superheater surface does not have sootblower coverage for the control of slagging. With the move to a high slagging fuel blend, controlling the accumulations of slag in the superheater section with the addition of new sootblowers will be critical to successful and reliable operation.

6) Furnace Imaging system – The addition of a high temperature imaging system to monitor superheater slagging conditions has proven to be a successful tool in the unit operator's ability to detect slag formations. The technology of these furnace cameras continues to improve allowing clear images of the heat transfer surface deep within the furnace and on the face of the superheater. These systems can be configured to alert the operator when a region has high temperatures so that actions may be taken to help avoid costly generation curtailments and/or unit outages.

7) Furnace Overlay – The switch to a higher sulfur coal and the use of Low NOx Burners will require protection of the furnace water walls from corrosion. The amount of overlay required is expected to be 5,000 square feet utilizing inconel 622 alloy.

8) Air Heater Modifications – The air heater will require modifications to address the SO_3 dew point temperature issue associated with downstream corrosion. This is accomplished through a change in basket depth.

9) Coal Yard Modifications – The current coal yard does not have the ability to blend different coals to achieve the desired 4.5# SO2 maximum. The installation of a second coal pile as well as a blending station will be required.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 9 of the Direct Testimony of Scott C. Weaver ("Weaver Testimony"), lines 27-29. For modeling purposes, the cost to comply with Coal Combustion Residual ("CCR") regulations has been estimated at $48 million. Provide support for this estimate.

RESPONSE

Please see Page 2 of this response.

WITNESS: Scott C Weaver

KPCo

2011-2020 CCR-Related Detail, Post-allocated, owned, less AFUDC, $000's

Project	Plant	Company	Rule	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2012 - 2020 Sum:
BS U2 Ash Waste-Water Treatment System	Big Sandy	KYPCO	CCR	0	1,747	8,735	17,471	6,988	0	0	0	0	34,941
BS Ash Pond Re-line	Big Sandy	KYPCO	CCR	0	0	0	0	889	4,121	4,245	0	0	9,255
Subtotal-Pre-Allocated				0	1,747	8,735	17,471	7,877	4,121	4,245	0	0	44,196
Corp. Overheads				0	159	795	1,590	717	375	386	0	0	4,022
Total Post-Allocated				0	1,906	9,530	19,061	8,594	4,496	4,631	0	0	48,218

KPSC Case No. 2011-00401
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Kentucky Power Company

REQUEST

Refer to pages 11-12 of the Weaver Testimony, Table1. Provide the Strategist model runs for each option and a detailed discussion of the main assumptions and economic drivers for each option run.

RESPONSE

Spreadsheet files that extract results from the Strategist model output files can be found on page 2 of this response. These five (5) spreadsheets offer the individual model run results that are reflective of one of the primary economic driver in the analysis--long-term commodity prices including natural gas, coal, energy (on and off-peak), and emissions value, including CO2/carbon. Each spreadsheet reflects a discrete "pricing scenario" that was detailed--in totality--on Exhibit SCW-4, and for each of those individual pricing scenarios on Exhibit SCW-4A, 4B, 4C, 4D and 4E, Attachments 1 through 5, respectively. Within each spreadsheet, those unique prices were applied to each of the five (5) Big Sandy "disposition options" evaluated.

A discussion of this commodity pricing can be found on Table 3, pages 28 & 29 of Mr. Weaver's testimony, as well as a narrative description of these pricing assumptions and impacts, starting on page 27, line 1, through page 30, line 14.

Another critical/main assumption in these modeling runs was the assumption around the installed costs of the various Big Sandy disposition alternatives. Those costs are identified on Table 2, found on page 24 of Mr. Weaver's testimony. Further, beginning on page 20, line 4, through page 24, line 3, that testimony also offers an overview of the critical drivers impacting each of those 4 unique Big Sandy disposition options evaluated.

Lastly, Exhibit SCW-1, pages 10-14, offers a narrative of the "key risk factors" that were set forth as part of the stochastic (Monte Carlo) modeling exercise also performed to support the discrete Strategist results.

WITNESS: Scott C Weaver

Big Sandy Unit 2 under BASE: "Fleet Transition-CSAPR" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025	BS2 "Timing" Sensitivity Option #1A BS2 DFGD Retrofit **Delayed until 1/2017** (~1-Yr EGU MACT Delay)
2011-2013						
2014				45 MW- ICAP	45 MW- ICAP	
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	225 MW- ICAP	225 MW- ICAP	Big Sandy 1 Retire
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP	Big Sandy 2 Mothball (1-yr)
2017				922 MW- ICAP	922 MW- ICAP	Big Sandy 2 Retrofit
2018				930 MW- ICAP	930 MW- ICAP	
2019				934 MW- ICAP	934 MW- ICAP	
2020				1 -904 MW NGCC	938 MW- ICAP	
2021					939 MW- ICAP	
2022					951 MW- ICAP	
2023					957 MW- ICAP	
2024					967 MW- ICAP	
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1- 407 MW CC	
2026 ~ 2040						
Life-Cycle Analysis Period (2011-2040) ($000)						
CPW of Revenue Requirements	6,724,489	7,152,559	7,079,239	6,811,507	6,487,042	6,721,898
Less: ICAP Revenue	(114,391)	77,262	(11,944)	(106,260)	(304,545)	(114,503)
CPW of Revenue Requirements, Net	6,838,879	7,075,297	7,091,182	6,917,767	6,791,587	6,836,401
A. Cost/(Savings) Over 'BASE' Case						
CPW of Revenue Requirements		428,070	354,750	87,018	(237,447)	(2,591)
Less: ICAP / Pool Revenue		191,652	102,447	8,130	(190,154)	(112)
CPW of Revenue Requirements, Net		236,418	252,303	78,888	(47,293)	(2,478)
B. Cost/(Savings) Over 'BASE' Case						
Impact of 20-Year (vs. 15-Year) RETROFIT Cost Recovery		37,200	37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		273,618	289,503	116,088	(10,093)	34,722

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

PRELIMINARY

Big Sandy 2 UD Analysis Under FTCA_CSAPR Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
2011				0 MW- ICAP	0 MW- ICAP
2012				0 MW- ICAP	0 MW- ICAP
2013				0 MW- ICAP	0 MW- ICAP
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire		Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	Big Sandy 2 Retrofit	Big Sandy 1 Retire 1 -780 MW Repower,	1 -904 MW NGCC	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				1 -904 MW NGCC	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1-407 MW CC
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
FTCA_CSAPR					
CPW	6,724,489	7,079,239	7,152,559	6,811,507	6,487,042
ICAP Revenue	(114,391)	(11,944)	77,262	(106,260)	(304,545)
Total	$6,838,879	$7,091,182	$7,075,297	$6,917,767	$6,791,587
Cost Over Retrofit		$252,303	$236,418	$78,888	($47,293)

PRELIMINARY

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Market Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607
2016	165,006	(48,054)	(85,222)	298,281	147,762	76,499	224,261	522,542	2,302	524,845	(96,221)	621,065	1,576,526	147,762
2017	236,355	(53,834)	28,377	261,812	147,762	137,403	285,165	546,977	1,511	548,488	(15,275)	563,763	1,919,419	147,762
2018	254,318	(54,857)	51,107	258,068	147,762	149,018	296,780	554,848	626	555,473	(13,781)	569,255	2,238,116	147,762
2019	242,101	(56,908)	22,817	276,191	147,762	139,475	287,237	563,428	572	564,000	(16,129)	580,129	2,537,072	147,762
2020	257,391	(58,754)	50,028	266,118	155,093	140,061	295,154	561,271	0	561,271	(18,970)	580,242	2,812,305	155,093
2021	263,061	(72,859)	57,490	278,430	155,093	143,776	298,869	577,298	0	577,298	(21,002)	598,301	3,073,534	155,093
2022	252,602	(73,893)	44,072	282,423	155,093	143,739	298,832	581,255	108,290	689,545	(24,128)	713,673	3,360,356	155,093
2023	225,510	(72,531)	(27,181)	325,222	155,093	140,117	295,210	620,431	96,073	716,505	(26,606)	743,111	3,635,257	155,093
2024	255,531	(77,447)	21,273	311,705	155,093	150,129	305,222	616,927	106,998	723,925	(29,365)	753,290	3,891,762	155,093
2025	336,073	(60,870)	136,139	260,804	257,945	166,903	424,848	685,653	116,552	802,205	20,285	781,919	4,136,841	257,945
2026	354,700	(61,862)	156,979	259,583	257,945	176,504	434,449	694,032	122,595	816,627	19,255	797,372	4,366,887	257,945
2027	351,082	(62,861)	134,514	279,429	257,945	174,827	432,772	712,201	119,821	832,023	17,955	814,067	4,583,071	257,945
2028	370,369	(63,743)	156,602	277,510	257,945	184,827	442,772	720,282	125,870	846,152	16,731	829,421	4,785,815	257,945
2029	370,732	(65,061)	141,804	293,989	257,945	188,259	446,204	740,193	124,788	864,981	15,461	849,520	4,976,958	257,945
2030	367,888	(64,315)	118,179	314,024	257,945	184,860	442,805	756,829	121,007	877,836	13,734	864,102	5,155,920	257,945
2031	388,156	(66,853)	144,828	310,181	146,766	148,849	295,615	605,796	128,489	734,285	11,814	722,471	5,293,649	146,766
2032	406,168	(67,107)	169,892	303,383	146,766	150,067	296,833	600,216	135,793	736,009	10,491	725,518	5,420,959	146,766
2033	411,019	(68,442)	163,642	315,819	146,766	149,262	296,028	611,847	136,812	748,659	7,036	741,623	5,540,746	146,766
2034	394,818	(69,438)	110,425	353,831	146,766	143,959	290,725	644,557	127,901	772,458	6,134	766,323	5,654,678	146,766
2035	408,588	(72,741)	122,805	358,523	146,766	155,220	301,986	660,509	133,275	793,784	5,012	788,772	5,762,622	146,766
2036	413,597	(74,000)	120,432	367,165	146,766	157,203	303,969	671,134	135,608	806,742	3,438	803,304	5,863,812	146,766
2037	426,893	(74,708)	132,956	368,645	146,766	158,887	305,653	674,298	141,194	815,492	868	814,624	5,958,266	146,766
2038	423,004	(77,575)	107,009	393,570	146,766	160,400	307,166	700,736	139,015	839,751	(1,085)	840,837	6,048,007	146,766
2039	432,896	(78,143)	113,529	397,511	146,766	163,017	309,783	707,294	143,353	850,646	(2,903)	853,549	6,131,859	146,766
2040	431,457	(80,190)	89,506	422,142	146,766	342,266	489,032	911,174	141,291	1,052,464	(2,592)	1,055,057	6,227,265	146,766
2011 Net Present Value														
Period of 2011-2040	3,169,734	(585,636)	700,340	3,055,030	1,257,570	1,078,614	2,336,184	5,391,214	721,660	6,112,874	(114,391)	6,227,265		
Base Case O&M 2011-2040							611,615			611,615	0	611,615		
Utility Cost Present Value 2011-2040							2,947,799			6,724,489	(114,391)	6,838,879		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(178)	1,652
2018	(189)	1,403
2019	(197)	1,572
2020	(206)	1,774
2021	(206)	1,960
2022	(218)	2,129
2023	(224)	2,280
2024	(234)	2,412
2025	155	2,524
2026	142	2,615
2027	129	2,685
2028	118	2,731
2029	108	2,751
2030	96	2,745
2031	82	2,765
2032	72	2,785
2033	48	2,805
2034	42	2,825
2035	34	2,845
2036	23	2,866
2037	6	2,887
2038	(7)	2,907
2039	(19)	2,928
2040	(17)	2,949

PRELIMINARY

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,375	6,944	0.34
2013	7,296	6,781	5,751	0.29
2014	5,050	7,009	5,319	0.33
2015	9,351	7,369	3,884	0.28
2016	4,097	5,144	2,089	0.15
2017	4,430	6,999	2,755	0.27
2018	4,358	7,419	2,785	0.28
2019	3,557	6,938	2,433	0.26
2020	4,573	7,448	1,741	0.27
2021	4,372	7,451	1,742	0.27
2022	4,559	7,182	1,676	0.25
2023	4,269	6,288	1,467	0.22
2024	3,655	6,914	1,619	0.25
2025	4,559	7,436	1,662	0.24
2026	3,917	7,718	1,739	0.26
2027	4,558	7,450	1,664	0.24
2028	3,884	7,726	1,742	0.27
2029	4,401	7,562	1,707	0.26
2030	4,332	7,236	1,610	0.23
2031	3,536	7,585	1,711	0.26
2032	4,572	7,914	1,783	0.27
2033	4,374	7,870	1,774	0.26
2034	4,558	7,263	1,618	0.23
2035	4,270	7,471	1,691	0.26
2036	3,658	7,504	1,701	0.26
2037	4,559	7,712	1,746	0.26
2038	3,917	7,495	1,701	0.26
2039	4,558	7,630	1,732	0.26
2040	3,886	7,423	1,688	0.26

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	80	2,136	2,057	6,900
2013	7,457	138	36	(102)	807	1,172	365	6,883
2014	7,469	139	17	(122)	690	1,367	677	6,894
2015	7,479	139	23	(116)	260	1,242	982	6,903
2016	7,488	139	19	(120)	2,373	743	(1,630)	6,911
2017	7,505	139	28	(111)	307	855	548	6,927
2018	7,536	139	37	(102)	154	1,139	985	6,955
2019	7,571	139	36	(103)	341	772	431	6,988
2020	7,604	139	34	(106)	174	1,132	958	7,019
2021	7,648	288	34	(254)	151	1,223	1,072	7,059
2022	7,695	288	34	(254)	354	1,044	690	7,102
2023	7,744	288	34	(254)	828	450	(378)	7,148
2024	7,798	289	34	(255)	384	702	318	7,198
2025	7,846	288	34	(254)	185	1,775	1,591	7,242
2026	7,896	288	34	(254)	140	1,990	1,851	7,288
2027	7,947	288	34	(254)	299	1,832	1,533	7,335
2028	7,999	289	34	(255)	167	1,930	1,764	7,383
2029	8,044	288	34	(254)	202	1,720	1,519	7,425
2030	8,093	288	34	(254)	515	1,712	1,197	7,470
2031	8,143	288	34	(254)	212	1,683	1,472	7,516
2032	8,195	289	34	(255)	134	1,888	1,754	7,564
2033	8,241	288	34	(254)	187	1,829	1,642	7,606
2034	8,289	288	34	(254)	474	1,447	973	7,651
2035	8,339	288	34	(254)	287	1,349	1,061	7,697
2036	8,389	289	34	(255)	319	1,317	999	7,743
2037	8,439	288	34	(254)	273	1,410	1,138	7,789
2038	8,488	288	34	(254)	307	1,123	816	7,835
2039	8,538	288	34	(254)	299	1,169	871	7,881
2040	8,589	289	34	(255)	443	1,020	577	7,927

	Reserve Margin - MW						Internal Sales PV 8.58%	2011 PV 2016-2040
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %		
2011	1,033	1,115		0	1,115	8.0%	6,860	
2012	1,251	1,316		0	1,316	5.2%	6,355	
2013	1,257	1,317		0	1,317	4.8%	5,838	
2014	1,243	1,387		0	1,387	11.6%	5,385	
2015	1,234	1,108		0	1,108	-10.2%	4,966	
2016	1,213	373	Retrofit	0	373	-69.3%	4,579	4,579
2017	1,198	1,116		0	1,116	-6.8%	4,227	4,227
2018	1,207	1,115		0	1,115	-7.6%	3,909	3,909
2019	1,218	1,119		0	1,119	-8.2%	3,617	3,617
2020	1,224	1,117		0	1,117	-8.8%	3,346	3,346
2021	1,238	1,131		0	1,131	-8.6%	3,099	3,099
2022	1,249	1,131		0	1,131	-9.4%	2,872	2,872
2023	1,255	1,131		0	1,131	-9.8%	2,662	2,662
2024	1,264	1,131		0	1,131	-10.5%	2,469	2,469
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%	2,288	2,288
2026	1,293	1,131		407	1,538	19.0%	2,120	2,120
2027	1,305	1,131		407	1,538	17.9%	1,965	1,965
2028	1,315	1,131		407	1,538	17.0%	1,822	1,822
2029	1,324	1,131		407	1,538	16.2%	1,687	1,687
2030	1,335	1,131		407	1,538	15.2%	1,563	1,563
2031	1,348	1,131		407	1,538	14.1%	1,449	1,449
2032	1,357	1,131		407	1,538	13.4%	1,343	1,343
2033	1,372	1,123		407	1,530	11.6%	1,244	1,244
2034	1,378	1,123		407	1,530	11.1%	1,152	1,152
2035	1,389	1,127		407	1,534	10.5%	1,067	1,067
2036	1,399	1,127		407	1,534	9.7%	989	989
2037	1,415	1,127		407	1,534	8.4%	916	916
2038	1,427	1,127		407	1,534	7.5%	849	849
2039	1,438	1,127		407	1,534	6.7%	786	786
2040	1,436	1,127		407	1,534	6.9%	728	728
							Sum	52,748

PRELIMINARY

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts											ICAP	
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	(0)	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	306,568	(45,520)	93,574	258,514	607	45,523	46,130	304,643	35,151	339,794	2,451	337,344	1,171,545	607	2015	31	1,507
2016	261,948	(47,806)	(10,420)	320,174	216,791	33,267	250,058	570,233	1,727	571,960	(16,179)	588,139	1,560,171	216,791	2016	(158)	1,973
2017	261,110	(46,021)	(24,759)	331,889	216,791	42,248	259,039	590,929	981	591,910	(12,240)	604,150	1,927,627	216,791	2017	(142)	1,652
2018	272,816	(46,171)	(15,680)	334,666	216,791	43,056	259,847	594,513	397	594,910	(10,916)	605,827	2,266,799	216,791	2018	(150)	1,403
2019	271,831	(45,831)	(30,291)	347,953	216,791	44,128	260,919	608,872	356	609,227	(12,596)	621,823	2,587,241	216,791	2019	(154)	1,572
2020	277,705	(46,875)	(15,282)	339,862	224,122	45,120	269,242	609,104	0	609,104	(14,619)	623,723	2,883,100	224,122	2020	(158)	1,774
2021	285,928	(61,526)	(10,484)	357,937	224,122	46,127	270,249	628,186	0	628,186	(16,195)	644,381	3,164,449	224,122	2021	(159)	1,960
2022	297,847	(62,966)	(11,911)	372,725	224,122	47,357	271,479	644,204	65,479	709,683	(18,906)	728,589	3,457,265	224,122	2022	(171)	2,129
2023	295,719	(62,635)	(39,828)	398,181	224,122	48,408	272,530	670,711	61,326	732,038	(21,014)	753,052	3,735,844	224,122	2023	(177)	2,280
2024	308,264	(63,573)	(36,796)	408,633	224,122	49,648	273,770	682,402	63,294	745,696	(23,450)	769,146	3,997,748	224,122	2024	(187)	2,412
2025	393,703	(58,312)	99,655	352,361	326,974	67,359	394,333	746,694	75,377	822,071	26,475	795,596	4,247,113	326,974	2025	202	2,524
2026	410,118	(59,436)	100,540	369,015	326,974	70,140	397,114	766,128	75,338	841,466	25,668	815,798	4,482,475	326,974	2026	189	2,615
2027	417,943	(60,004)	104,034	373,913	326,974	71,257	398,231	772,144	78,308	850,452	24,539	825,913	4,701,805	326,974	2027	176	2,685
2028	429,257	(61,112)	97,556	392,812	326,974	73,527	400,501	793,313	77,225	870,538	23,428	847,110	4,908,873	326,974	2028	165	2,731
2029	436,546	(62,691)	86,970	412,267	326,974	75,375	402,349	814,616	76,259	890,875	22,206	868,668	5,104,325	326,974	2029	155	2,751
2030	446,505	(62,816)	99,848	409,473	326,974	76,846	403,820	813,293	80,663	893,956	20,466	873,489	5,285,230	326,974	2030	143	2,745
2031	455,572	(64,317)	89,830	430,060	326,974	79,413	406,387	836,446	78,857	915,303	18,594	896,709	5,456,175	326,974	2031	129	2,765
2032	466,718	(64,710)	107,526	423,902	326,974	80,720	407,694	831,596	84,626	916,221	17,320	898,901	5,613,910	326,974	2032	120	2,785
2033	473,614	(66,050)	103,064	436,600	326,974	82,426	409,400	846,000	85,546	931,546	13,915	917,631	5,762,125	326,974	2033	95	2,805
2034	483,685	(67,499)	102,033	449,151	326,974	84,412	411,386	860,537	86,876	947,413	13,062	934,351	5,901,039	326,974	2034	89	2,825
2035	483,601	(69,616)	74,349	478,868	326,974	86,694	413,668	892,537	82,550	975,087	11,990	963,097	6,032,839	326,974	2035	81	2,845
2036	491,883	(71,173)	75,349	487,707	146,766	88,252	235,018	722,724	84,625	807,349	10,466	796,883	6,133,220	146,766	2036	70	2,866
2037	500,999	(71,342)	83,539	488,802	146,766	89,390	236,156	724,957	89,675	814,632	7,947	806,685	6,226,754	146,766	2037	53	2,887
2038	499,784	(73,241)	61,040	511,985	146,766	91,072	237,838	749,823	87,425	837,248	6,044	831,204	6,315,467	146,766	2038	40	2,907
2039	509,032	(74,284)	65,129	518,187	146,766	92,618	239,384	757,571	91,212	848,783	4,278	844,505	6,398,430	146,766	2039	28	2,928
2040	511,478	(76,024)	46,326	541,176	146,766	124,803	271,569	812,746	89,166	901,912	4,640	897,272	6,479,568	146,766	2040	30	2,949
2011 Net Present Value																	
Period of 2011-2040	3,574,130	(535,075)	449,472	3,659,732	1,812,173	452,326	2,264,499	5,924,232	543,392	6,467,624	(11,944)	6,479,568					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							*2,876,114*			*7,079,239*	*(11,944)*	*7,091,182*					

PRELIMINARY

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,375	6,944	0.34
2013	7,296	6,781	5,751	0.29
2014	5,050	7,009	5,319	0.33
2015	9,351	8,110	6,039	0.32
2016	4,097	4,176	1,635	0.01
2017	4,430	4,028	1,812	0.01
2018	4,358	4,244	1,793	0.01
2019	3,557	4,026	1,505	0.01
2020	4,573	4,338	764	0.00
2021	4,372	4,327	762	0.00
2022	4,559	4,342	764	0.00
2023	4,269	4,014	694	0.00
2024	3,655	4,090	709	0.00
2025	4,559	4,809	808	0.00
2026	3,917	4,743	783	0.00
2027	4,558	4,869	814	0.00
2028	3,884	4,740	781	0.00
2029	4,401	4,621	754	0.00
2030	4,332	4,824	800	0.00
2031	3,536	4,655	758	0.00
2032	4,572	4,932	822	0.00
2033	4,374	4,921	820	0.00
2034	4,558	4,934	822	0.00
2035	4,270	4,627	754	0.00
2036	3,658	4,683	767	0.00
2037	4,559	4,898	819	0.00
2038	3,917	4,714	781	0.00
2039	4,558	4,855	814	0.00
2040	3,886	4,685	777	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	80	2,136	2,057	6,900
2013	7,457	138	36	(102)	807	1,172	365	6,883
2014	7,469	139	17	(122)	690	1,367	677	6,894
2015	7,479	139	23	(116)	139	1,927	1,788	6,903
2016	7,488	139	19	(120)	621	368	(253)	6,911
2017	7,505	139	28	(111)	766	284	(482)	6,927
2018	7,536	139	37	(102)	622	319	(303)	6,955
2019	7,571	139	36	(103)	843	279	(565)	6,986
2020	7,604	139	34	(106)	612	346	(267)	7,019
2021	7,648	288	34	(254)	569	393	(176)	7,059
2022	7,695	288	34	(254)	559	390	(169)	7,102
2023	7,744	288	34	(254)	855	268	(586)	7,148
2024	7,798	289	34	(255)	807	278	(529)	7,198
2025	7,846	288	34	(254)	421	1,408	986	7,242
2026	7,896	288	34	(254)	346	1,384	1,038	7,288
2027	7,947	288	34	(254)	390	1,439	1,049	7,335
2028	7,999	289	34	(255)	390	1,336	946	7,383
2029	8,044	288	34	(254)	424	1,223	800	7,425
2030	8,093	288	34	(254)	409	1,338	928	7,470
2031	8,143	288	34	(254)	461	1,259	798	7,516
2032	8,195	289	34	(255)	425	1,397	972	7,564
2033	8,241	288	34	(254)	402	1,307	904	7,606
2034	8,289	288	34	(254)	364	1,250	887	7,651
2035	8,339	288	34	(254)	497	1,038	541	7,697
2036	8,389	289	34	(255)	478	1,009	531	7,743
2037	8,439	288	34	(254)	402	1,024	622	7,789
2038	8,488	288	34	(254)	512	859	347	7,835
2039	8,538	288	34	(254)	470	864	394	7,881
2040	8,589	289	34	(255)	572	743	171	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

PRELIMINARY

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0
2014	276,567	(38,222)	58,226	256,564	607	(0)	607	257,171	102,595	359,766	1,379	358,386	929,379	607
2015	275,723	(51,086)	45,062	281,748	607	1	608	282,356	29,797	312,153	(17,667)	329,819	1,166,144	607
2016	265,889	(46,190)	(5,161)	319,241	219,322	33,361	252,683	571,924	1,730	573,654	(3,454)	577,108	1,547,481	219,322
2017	264,881	(46,427)	(19,759)	331,067	219,322	42,256	261,578	592,645	983	593,628	(1,589)	595,217	1,909,504	219,322
2018	276,542	(46,694)	(10,689)	333,925	219,322	42,920	262,242	596,167	398	596,565	(1,871)	598,436	2,244,539	219,322
2019	275,802	(46,745)	(24,712)	347,259	219,322	43,738	263,060	610,319	356	610,676	(2,460)	613,136	2,560,503	219,322
2020	281,618	(47,538)	(9,953)	339,109	226,653	44,543	271,196	610,304	0	610,304	(3,179)	613,483	2,851,504	226,653
2021	290,148	(62,012)	(5,000)	357,159	226,653	45,380	272,033	629,193	0	629,193	(3,555)	632,747	3,127,774	226,653
2022	302,092	(63,388)	(5,857)	371,336	226,653	46,444	273,097	644,433	65,933	710,366	(5,177)	715,543	3,415,347	226,653
2023	300,374	(63,334)	(33,065)	396,774	226,653	47,320	273,973	670,747	61,817	732,564	(6,312)	738,877	3,688,682	226,653
2024	313,032	(64,305)	(29,869)	407,206	226,653	48,351	275,004	682,210	63,787	745,997	(7,897)	753,894	3,945,392	226,653
2025	397,097	(58,035)	104,722	350,410	329,505	65,757	395,262	745,672	75,723	821,395	42,751	778,645	4,189,444	329,505
2026	414,742	(59,125)	106,929	366,938	329,505	68,403	397,908	764,846	75,810	840,656	42,532	798,124	4,419,707	329,505
2027	421,946	(59,730)	109,782	371,894	329,505	69,273	398,778	770,672	78,712	849,384	41,849	807,536	4,634,157	329,505
2028	433,804	(60,821)	103,872	390,753	329,505	71,359	400,864	791,617	77,680	869,297	41,037	828,260	4,836,618	329,505
2029	441,578	(62,380)	93,777	410,181	329,505	73,056	402,561	812,742	76,755	889,498	39,942	849,556	5,027,769	329,505
2030	451,055	(62,446)	106,218	407,283	329,505	74,234	403,739	811,022	81,114	892,136	38,167	853,969	5,204,632	329,505
2031	460,422	(63,997)	96,615	427,804	329,505	76,575	406,080	833,884	79,339	913,223	36,423	876,800	5,371,781	329,505
2032	471,622	(64,319)	114,474	421,467	329,505	77,631	407,136	828,604	85,113	913,717	35,277	878,440	5,525,926	329,505
2033	475,881	(65,655)	107,888	433,647	329,505	78,914	408,419	842,066	85,772	927,838	32,000	895,837	5,670,621	329,505
2034	490,443	(67,175)	111,328	446,290	329,505	80,990	410,495	856,785	87,547	944,332	31,279	913,053	5,806,368	329,505
2035	488,660	(69,177)	81,730	476,107	329,505	82,817	412,322	888,429	83,055	971,484	30,337	941,147	5,935,165	329,505
2036	497,150	(70,743)	83,039	484,854	329,505	84,290	413,795	898,649	85,148	983,797	28,946	954,851	6,055,444	329,505
2037	505,038	(70,949)	89,906	486,082	329,505	85,193	414,698	900,779	90,083	990,862	26,560	964,302	6,167,254	329,505
2038	504,709	(72,900)	68,668	508,941	329,505	86,844	416,349	925,291	87,914	1,013,205	24,791	988,414	6,272,745	329,505
2039	514,193	(73,770)	73,028	514,935	329,505	88,291	417,796	932,731	91,723	1,024,455	23,160	1,001,295	6,371,112	329,505
2040	515,003	(75,518)	52,379	538,143	329,505	90,192	419,697	957,840	89,527	1,047,366	23,658	1,023,708	6,463,682	329,505
2011 Net Present Value														
Period of 2011-2040	3,582,748	(540,539)	457,930	3,665,357	1,927,380	406,823	2,334,203	5,999,560	541,384	6,540,944	77,262	6,463,682		
Base Case O&M 2011-2040							611,615			611,615	0	611,615		
Utility Cost Present Value 2011-2040							2,945,818			7,152,559	77,262	7,075,297		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(34)	1,973
2017	(18)	1,652
2018	(26)	1,403
2019	(30)	1,572
2020	(34)	1,774
2021	(35)	1,960
2022	(47)	2,129
2023	(53)	2,280
2024	(63)	2,412
2025	326	2,524
2026	313	2,615
2027	300	2,685
2028	289	2,731
2029	279	2,751
2030	267	2,745
2031	253	2,765
2032	244	2,785
2033	219	2,805
2034	213	2,825
2035	205	2,845
2036	194	2,866
2037	177	2,887
2038	164	2,907
2039	152	2,928
2040	154	2,949

PRELIMINARY

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FTCA CSAPR Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,375	6,944	0.34
2013	7,296	6,781	5,751	0.29
2014	5,050	7,009	5,319	0.33
2015	9,351	7,370	3,884	0.28
2016	4,097	4,209	1,638	0.01
2017	4,430	4,059	1,815	0.01
2018	4,358	4,273	1,796	0.01
2019	3,557	4,056	1,508	0.01
2020	4,573	4,368	767	0.00
2021	4,372	4,358	765	0.00
2022	4,559	4,373	767	0.00
2023	4,269	4,046	697	0.00
2024	3,655	4,122	712	0.00
2025	4,559	4,831	810	0.00
2026	3,917	4,773	786	0.00
2027	4,558	4,894	817	0.00
2028	3,884	4,768	784	0.00
2029	4,401	4,652	757	0.00
2030	4,332	4,851	803	0.00
2031	3,536	4,684	761	0.00
2032	4,572	4,960	825	0.00
2033	4,374	4,934	821	0.00
2034	4,558	4,972	826	0.00
2035	4,270	4,656	757	0.00
2036	3,658	4,712	771	0.00
2037	4,559	4,920	821	0.00
2038	3,917	4,740	784	0.00
2039	4,558	4,882	817	0.00
2040	3,886	4,704	779	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	80	2,136	2,057	6,900
2013	7,457	138	36	(102)	807	1,172	365	6,883
2014	7,469	139	17	(122)	690	1,367	677	6,894
2015	7,479	139	23	(116)	260	1,242	982	6,903
2016	7,488	139	19	(120)	575	410	(165)	6,911
2017	7,505	139	28	(111)	716	316	(400)	6,927
2018	7,536	139	37	(102)	580	355	(225)	6,955
2019	7,571	139	36	(103)	789	311	(478)	6,988
2020	7,604	139	34	(106)	571	384	(187)	7,019
2021	7,648	288	34	(254)	529	436	(93)	7,059
2022	7,695	288	34	(254)	519	427	(91)	7,102
2023	7,744	288	34	(254)	797	298	(499)	7,148
2024	7,798	289	34	(255)	752	309	(443)	7,198
2025	7,846	288	34	(254)	421	1,465	1,044	7,242
2026	7,896	288	34	(254)	333	1,449	1,117	7,288
2027	7,947	288	34	(254)	387	1,502	1,116	7,335
2028	7,999	289	34	(255)	378	1,398	1,020	7,383
2029	8,044	288	34	(254)	407	1,286	879	7,425
2030	8,093	288	34	(254)	402	1,401	999	7,470
2031	8,143	288	34	(254)	447	1,319	872	7,516
2032	8,195	289	34	(255)	414	1,460	1,047	7,564
2033	8,241	288	34	(254)	419	1,359	940	7,606
2034	8,289	288	34	(254)	345	1,334	989	7,651
2035	8,339	288	34	(254)	484	1,099	615	7,697
2036	8,389	289	34	(255)	466	1,072	606	7,743
2037	8,439	288	34	(254)	400	1,078	678	7,789
2038	8,488	288	34	(254)	499	915	416	7,835
2039	8,538	288	34	(254)	457	920	464	7,881
2040	8,589	289	34	(255)	567	785	218	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions

[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

D.

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts													
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	928,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	72,505	(39,933)	(262,595)	375,034	36,583	0	36,583	411,617	1,596	413,213	(96,221)	509,433	1,502,763	36,583	2016	(938)	1,973
2017	69,730	(38,322)	(276,013)	384,065	36,583	0	36,583	420,648	895	421,543	(79,238)	500,781	1,807,349	36,583	2017	(922)	1,652
2018	76,949	(37,921)	(270,260)	385,130	36,583	0	36,583	421,713	359	422,072	(67,811)	489,883	2,081,610	36,583	2018	(930)	1,403
2019	71,023	(38,178)	(290,487)	399,689	36,583	0	36,583	436,272	317	436,589	(76,355)	512,944	2,345,943	36,583	2019	(934)	1,572
2020	281,553	(47,516)	(10,052)	339,121	238,249	44,537	282,786	621,907	0	621,907	(3,179)	625,085	2,642,447	238,249	2020	(34)	1,774
2021	290,179	(62,012)	(4,964)	357,155	238,249	45,383	283,632	640,786	0	640,786	(3,555)	644,341	2,923,779	238,249	2021	(35)	1,960
2022	301,970	(63,388)	(6,019)	371,377	238,249	46,434	284,683	656,060	65,920	721,980	(5,177)	727,157	3,216,019	238,249	2022	(47)	2,129
2023	300,421	(63,334)	(33,005)	396,760	238,249	47,324	285,573	682,333	61,822	744,156	(6,312)	750,468	3,493,642	238,249	2023	(53)	2,280
2024	313,025	(64,305)	(29,873)	407,203	238,249	48,350	286,599	693,802	63,786	757,588	(7,897)	765,485	3,754,300	238,249	2024	(63)	2,412
2025	397,097	(58,035)	104,722	350,410	341,101	65,757	406,858	757,268	75,723	832,991	42,751	790,241	4,001,986	341,101	2025	326	2,524
2026	414,742	(59,125)	105,929	366,938	341,101	68,403	409,504	776,442	75,810	852,252	42,532	809,720	4,235,595	341,101	2026	313	2,615
2027	421,946	(59,730)	109,782	371,894	341,101	69,273	410,374	782,268	78,712	860,980	41,849	819,132	4,453,124	341,101	2027	300	2,685
2028	433,804	(60.821)	103,872	390,753	341,101	71,359	412,460	803,213	77,680	880,893	41,037	839,856	4,658,419	341,101	2028	289	2,731
2029	441,579	(62,360)	93,777	410,181	341,101	73,056	414,157	824,338	76,755	901,094	39,942	861,152	4,852,179	341,101	2029	279	2,751
2030	451,055	(62,446)	106,218	407,283	341,101	74,234	415,335	822,618	81,114	903,732	38,167	865,565	5,031,444	341,101	2030	267	2,745
2031	460,422	(63,997)	96,615	427,804	341,101	76,575	417,676	845,480	79,339	924,819	36,423	888,396	5,200,804	341,101	2031	253	2,765
2032	471,622	(64,319)	114,474	421,467	341,101	77,631	418,732	840,200	85,113	925,313	35,277	890,036	5,356,983	341,101	2032	244	2,785
2033	475,827	(65,655)	107,830	433,652	341,101	78,909	420,010	853,662	85,766	939,428	32,000	907,428	5,503,551	341,101	2033	219	2,805
2034	490,443	(67,175)	111,328	446,290	341,101	80,990	422,091	868,381	87,547	955,928	31,279	924,649	5,641,022	341,101	2034	213	2,825
2035	488,660	(69,177)	81,730	476,107	341,101	82,817	423,918	900,025	83,055	983,080	30,337	952,743	5,771,405	341,101	2035	205	2,845
2036	497,150	(70,743)	83,039	484,854	341,101	84,290	425,391	910,245	85,148	995,393	28,946	966,447	5,893,146	341,101	2036	194	2,866
2037	504,986	(70,949)	89,848	486,087	341,101	85,188	426,289	912,376	90,078	1,002,454	26,560	975,894	6,006,299	341,101	2037	177	2,887
2038	504,647	(72,900)	68,598	508,950	341,101	86,839	427,940	936,889	87,908	1,024,798	24,791	1,000,007	6,113,028	341,101	2038	164	2,907
2039	514,193	(73,770)	73,028	514,935	341,101	88,291	429,392	944,327	91,723	1,036,051	23,160	1,012,891	6,212,534	341,101	2039	152	2,928
2040	514,966	(75,518)	52,337	538,148	341,101	90,188	431,289	969,437	89,523	1,058,961	23,658	1,035,302	6,306,153	341,101	2040	154	2,949
2011 Net Present Value																	
Period of 2011-2040	3,118,913	(520,817)	(150,432)	3,790,161	1,556,036	312,502	1,868,539	5,658,700	541,192	6,199,892	(106.260)	6,306,153					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,480,153			6,811,507	(106,260)	6,917,767					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,375	6,944	0.34
2013	7,296	6,781	5,751	0.29
2014	5,050	7,009	5,319	0.33
2015	9,351	7,369	3,884	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	4,367	767	0.00
2021	4,372	4,358	765	0.00
2022	4,559	4,372	767	0.00
2023	4,269	4,046	697	0.00
2024	3,655	4,122	712	0.00
2025	4,559	4,831	810	0.00
2026	3,917	4,773	786	0.00
2027	4,558	4,894	817	0.00
2028	3,884	4,768	784	0.00
2029	4,401	4,652	757	0.00
2030	4,332	4,851	803	0.00
2031	3,536	4,684	761	0.00
2032	4,572	4,960	825	0.00
2033	4,374	4,934	821	0.00
2034	4,558	4,972	826	0.00
2035	4,270	4,656	757	0.00
2036	3,658	4,712	771	0.00
2037	4,559	4,920	821	0.00
2038	3,917	4,740	784	0.00
2039	4,558	4,882	817	0.00
2040	3,886	4,703	779	0.00

	Summary of Energy Purchases and Sales (Gwh)							
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	80	2,136	2,057	6,900
2013	7,457	138	36	(102)	807	1,172	365	6,883
2014	7,469	139	17	(122)	690	1,367	677	6,894
2015	7,479	139	23	(116)	260	1,242	982	6,903
2016	7,488	139	19	(120)	4,621		(4,621)	6,911
2017	7,505	139	28	(111)	4,778		(4,778)	6,927
2018	7,536	139	37	(102)	4,579		(4,579)	6,955
2019	7,571	139	36	(103)	4,855		(4,855)	6,988
2020	7,604	139	34	(106)	573	384	(189)	7,019
2021	7,646	288	34	(254)	528	436	(93)	7,059
2022	7,695	288	34	(254)	520	426	(94)	7,102
2023	7,744	288	34	(254)	796	298	(498)	7,148
2024	7,798	289	34	(255)	752	309	(443)	7,198
2025	7,846	288	34	(254)	421	1,465	1,044	7,242
2026	7,896	288	34	(254)	333	1,449	1,117	7,288
2027	7,947	288	34	(254)	387	1,502	1,116	7,335
2028	7,999	289	34	(255)	378	1,398	1,020	7,383
2029	8,044	288	34	(254)	407	1,286	879	7,425
2030	8,093	288	34	(254)	402	1,401	999	7,470
2031	8,143	288	34	(254)	447	1,319	872	7,516
2032	8,195	289	34	(255)	414	1,460	1,047	7,564
2033	8,241	288	34	(254)	420	1,359	939	7,606
2034	8,289	288	34	(254)	345	1,334	989	7,651
2035	8,339	288	34	(254)	484	1,099	615	7,697
2036	8,389	289	34	(255)	466	1,072	606	7,743
2037	8,439	288	34	(254)	401	1,078	677	7,789
2038	8,488	288	34	(254)	500	915	415	7,835
2039	8,538	288	34	(254)	457	920	464	7,881
2040	8,589	289	34	(255)	568	785	217	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	1,288	1 -904 MW NGCC,	0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,465	(21,183)	95,923	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0	2012	0	388
2013	227,817	(30,153)	37,371	220,599	0	0	0	220,599	51,659	272,258	0	272,258	649,879	0	2013	0	161
2014	276,567	(38,222)	58,226	256,564	607	0	607	257,171	102,595	359,766	1,379	358,386	929,379	607	2014	45	595
2015	275,707	(51,088)	45,044	281,751	607	0	607	282,358	29,795	312,153	(17,667)	329,820	1,166,144	607	2015	(225)	1,507
2016	72,505	(39,933)	(262,595)	375,034	36,583	0	36,583	411,617	1,596	413,213	(96,221)	509,433	1,502,763	36,583	2016	(938)	1,973
2017	69,730	(38,322)	(276,013)	384,065	36,583	0	36,583	420,648	895	421,543	(79,238)	500,781	1,807,349	36,583	2017	(922)	1,652
2018	76,949	(37,921)	(270,260)	385,130	36,583	0	36,583	421,713	359	422,072	(67,811)	489,883	2,081,610	36,583	2018	(930)	1,403
2019	71,023	(38,178)	(290,487)	399,689	36,583	0	36,583	436,272	317	436,589	(76,355)	512,944	2,345,943	36,583	2019	(934)	1,572
2020	75,257	(38,014)	(279,386)	392,657	43,914	0	43,914	436,571	0	436,571	(86,584)	523,156	2,594,098	43,914	2020	(938)	1,774
2021	76,468	(52,948)	(279,891)	409,307	43,914	0	43,914	453,221	0	453,221	(95,706)	548,927	2,833,769	43,914	2021	(939)	1,960
2022	76,760	(53,230)	(327,351)	457,341	43,914	0	43,914	501,255	41,846	543,102	(105,268)	648,370	3,094,346	43,914	2022	(951)	2,129
2023	69,002	(53,442)	(360,111)	482,555	43,914	0	43,914	526,469	37,415	563,884	(113,496)	677,380	3,344,931	43,914	2023	(957)	2,280
2024	72,372	(55,536)	(367,599)	495,506	43,914	0	43,914	539,420	38,892	578,313	(121,283)	699,595	3,583,152	43,914	2024	(967)	2,412
2025	397,097	(58,035)	104,722	350,410	356,636	65,757	422,393	772,803	75,723	848,526	42,751	805,776	3,835,708	356,636	2025	326	2,524
2026	414,742	(59,125)	106,929	366,938	356,636	68,403	425,039	791,977	75,810	867,787	42,532	825,255	4,073,799	356,636	2026	313	2,615
2027	421,946	(59,730)	109,782	371,894	356,636	69,273	425,909	797,803	78,712	876,515	41,849	834,667	4,295,454	356,636	2027	300	2,685
2028	433,804	(60,821)	103,872	390,753	356,636	71,359	427,995	818,748	77,680	896,428	41,037	855,391	4,504,546	356,636	2028	289	2,731
2029	441,579	(62,380)	93,777	410,181	356,636	73,056	429,692	839,873	76,755	916,629	39,942	876,687	4,701,802	356,636	2029	279	2,751
2030	451,055	(62,446)	106,218	407,283	356,636	74,234	430,870	838,153	81,114	919,267	38,167	881,100	4,884,284	356,636	2030	267	2,745
2031	460,422	(63,997)	96,615	427,804	356,636	76,575	433,211	861,015	79,339	940,354	36,423	903,931	5,056,605	356,636	2031	253	2,765
2032	471,622	(64,319)	114,474	421,467	356,636	77,631	434,267	855,735	85,113	940,848	35,277	905,571	5,215,510	356,636	2032	244	2,785
2033	475,827	(65,655)	107,830	433,652	356,636	78,909	435,545	869,197	85,766	954,963	32,000	922,963	5,364,587	356,636	2033	219	2,805
2034	490,443	(67,175)	111,328	446,290	356,636	80,990	437,626	883,916	87,547	971,463	31,279	940,184	5,504,368	356,636	2034	213	2,825
2035	488,660	(69,177)	81,730	476,107	356,636	82,817	439,453	915,560	83,055	998,615	30,337	968,278	5,636,877	356,636	2035	205	2,845
2036	497,150	(70,743)	83,039	484,854	356,636	84,290	440,926	925,780	85,148	1,010,928	28,946	981,982	5,760,574	356,636	2036	194	2,866
2037	504,986	(70,949)	89,848	486,087	356,636	85,188	441,824	927,911	90,078	1,017,989	26,560	991,429	5,875,530	356,636	2037	177	2,887
2038	504,647	(72,900)	68,598	508,950	356,636	86,839	443,475	952,424	87,908	1,040,333	24,791	1,015,542	5,983,916	356,636	2038	164	2,907
2039	514,193	(73,770)	73,028	514,935	356,636	88,291	444,927	959,862	91,723	1,051,586	23,160	1,028,426	6,084,948	356,636	2039	152	2,928
2040	514,966	(75,518)	52,337	538,148	356,636	90,188	446,824	984,972	89,523	1,074,496	23,658	1,050,837	6,179,972	356,636	2040	154	2,949
2011 Net Present Value																	
Period of 2011-2040	2,669,682	(501,624)	(763,376)	3,934,682	1,207,804	218,929	1,426,733	5,361,415	514,012	5,875,427	(304,545)	6,179,972					
Base Case O&M 2011-2040							611,615			611,615	0	611,615					
Utility Cost Present Value 2011-2040							2,038,348			6,487,042	(304,545)	6,791,587					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FTCA CSAPR Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,375	6,944	0.34
2013	7,296	6,781	5,751	0.29
2014	5,050	7,009	5,319	0.33
2015	9,351	7,369	3,884	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	2,783	597	0.00
2021	4,372	2,775	595	0.00
2022	4,559	2,775	595	0.00
2023	4,269	2,449	525	0.00
2024	3,655	2,513	539	0.00
2025	4,559	4,831	810	0.00
2026	3,917	4,773	766	0.00
2027	4,558	4,894	817	0.00
2028	3,884	4,768	784	0.00
2029	4,401	4,652	757	0.00
2030	4,332	4,851	803	0.00
2031	3,536	4,684	761	0.00
2032	4,572	4,960	825	0.00
2033	4,374	4,934	821	0.00
2034	4,558	4,972	826	0.00
2035	4,270	4,656	757	0.00
2036	3,658	4,712	771	0.00
2037	4,559	4,920	821	0.00
2038	3,917	4,740	784	0.00
2039	4,558	4,882	817	0.00
2040	3,886	4,703	779	0.00

	Summary of Energy Purchases and Sales (Gwh)							
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	80	2,136	2,057	6,900
2013	7,457	138	36	(102)	807	1,172	365	6,883
2014	7,469	139	17	(122)	690	1,367	677	6,894
2015	7,479	139	23	(116)	260	1,242	982	6,903
2016	7,488	139	19	(120)	4,621		(4,621)	6,911
2017	7,505	139	28	(111)	4,778		(4,778)	6,927
2018	7,536	139	37	(102)	4,579		(4,579)	6,955
2019	7,571	139	36	(103)	4,855		(4,855)	6,988
2020	7,604	139	34	(106)	4,566		(4,566)	7,019
2021	7,648	288	34	(254)	4,458		(4,458)	7,059
2022	7,695	288	34	(254)	4,495		(4,495)	7,102
2023	7,744	288	34	(254)	4,902		(4,902)	7,148
2024	7,798	289	34	(255)	4,870		(4,870)	7,198
2025	7,846	288	34	(254)	421	1,465	1,044	7,242
2026	7,896	288	34	(254)	333	1,449	1,117	7,288
2027	7,947	288	34	(254)	387	1,502	1,116	7,335
2028	7,999	289	34	(255)	378	1,398	1,020	7,383
2029	8,044	288	34	(254)	407	1,286	879	7,425
2030	8,093	288	34	(254)	402	1,401	999	7,470
2031	8,143	288	34	(254)	447	1,319	872	7,516
2032	8,195	289	34	(255)	414	1,460	1,047	7,564
2033	8,241	288	34	(254)	420	1,359	939	7,606
2034	8,289	288	34	(254)	345	1,334	989	7,651
2035	8,339	288	34	(254)	484	1,099	615	7,697
2036	8,389	289	34	(255)	466	1,072	606	7,743
2037	8,439	288	34	(254)	401	1,078	677	7,789
2038	8,488	288	34	(254)	500	915	415	7,835
2039	8,538	288	34	(254)	457	920	464	7,881
2040	8,589	289	34	(255)	568	785	217	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,303	1- 407 MW CC,1 -904 MW NGCC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions

[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Big Sandy Unit 2 under: "Fleet Transition-HIGHER Band" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013					
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	225 MW- ICAP	225 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				1 -904 MW NGCC	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1- 407 MW CC
2026 ~ 2040					

Life-Cycle Analysis Period (2011-2040) ($000)					
CPW of Revenue Requirements	7,178,617	7,816,447	7,741,800	7,477,588	7,189,328
Less: ICAP Revenue	(111,382)	89,299	(6,332)	(78,460)	(292,309)
CPW of Revenue Requirements, Net	7,290,000	7,727,148	7,748,132	7,556,049	7,481,637
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		637,830	563,183	298,971	10,711
Less: ICAP / Pool Revenue		200,682	105,050	32,922	(180,927)
CPW of Revenue Requirements, Net		437,149	458,132	266,049	191,638
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year) *RETROFIT Cost Recovery*		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		474,349	495,332	303,249	228,838

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Big Sandy 2 UD Analysis Under FT_CSAPR High Band Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life	***BS1 Repower 20 yr book life***	***NGCC Replacement***	***Market to 2020***	***Market to 2025***
2011				0 MW- ICAP	0 MW- ICAP
2012				0 MW- ICAP	0 MW- ICAP
2013				0 MW- ICAP	0 MW- ICAP
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire		Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	**Big Sandy 2 Retrofit**	**Big Sandy 1 Retire** **1 -780 MW Repower,**	**1 -904 MW NGCC**	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				**1 -904 MW NGCC**	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1 -904 MW NGCC, 1- 407 MW CC**
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
FTCA_CSAPR					
High Band					
CPW	7,178,617	7,741,800	7,816,447	7,477,588	7,189,328
ICAP Revenue	(111,382)	(6,332)	89,299	(78,460)	(292,309)
Total	$7,290,000	$7,748,132	$7,727,148	$7,556,049	$7,481,637
Cost Over Retrofit		$458,132	$437,149	$266,049	$191,638

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR High Band Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	192,631	(12,788)	40,914	164,505	0	0	0	164,505	7,418	171,923	0	171,923	171,923	0	2011	0	958
2012	256,683	(21,746)	102,195	176,235	0	0	0	176,235	113,060	289,294	0	289,294	438,210	0	2012	0	388
2013	238,029	(31,187)	54,443	214,773	0	0	0	214,773	76,728	291,500	0	291,500	685,189	0	2013	0	161
2014	342,568	(39,475)	92,284	289,759	607	0	607	290,366	128,873	419,240	1,379	417,860	1,011,072	607	2014	45	595
2015	318,242	(52,896)	52,989	318,150	607	0	607	318,757	42,898	361,655	(17,667)	379,322	1,283,373	607	2015	(225)	1,507
2016	194,594	(49,025)	(95,771)	339,390	147,762	76,639	224,401	563,791	2,829	566,620	(96,221)	662,840	1,721,358	147,762	2016	(938)	1,973
2017	274,215	(55,865)	35,277	294,804	147,762	137,810	285,572	580,376	2,105	582,481	(12,923)	595,404	2,083,495	147,762	2017	(178)	1,397
2018	295,141	(57,272)	62,114	290,299	147,762	149,491	297,253	587,552	1,004	588,557	(11,446)	600,002	2,419,407	147,762	2018	(189)	1,165
2019	280,553	(59,427)	27,837	312,143	147,762	139,760	287,522	599,666	358	600,023	(15,184)	615,207	2,736,439	147,762	2019	(197)	1,480
2020	307,707	(61,168)	61,289	307,585	155,093	140,560	295,653	603,238	0	603,238	(18,999)	622,237	3,031,593	155,093	2020	(206)	1,777
2021	313,301	(76,156)	67,605	321,855	155,093	144,003	299,096	620,950	0	620,950	(22,023)	642,973	3,312,327	155,093	2021	(206)	2,056
2022	303,196	(76,545)	53,577	326,164	155,093	144,219	299,312	625,475	108,823	734,298	(26,227)	760,525	3,617,978	155,093	2022	(218)	2,315
2023	272,159	(74,952)	(25,204)	372,315	155,093	140,676	295,769	668,084	96,690	764,774	(29,787)	794,561	3,911,912	155,093	2023	(224)	2,553
2024	304,803	(80,725)	26,804	358,724	155,093	150,520	305,613	664,338	107,427	771,765	(33,403)	805,167	4,186,082	155,093	2024	(234)	2,744
2025	403,691	(61,625)	159,336	305,981	257,945	167,524	425,469	731,450	117,235	848,684	22,796	825,889	4,444,942	257,945	2025	155	2,836
2026	422,978	(62,899)	181,313	304,564	257,945	176,946	434,891	739,455	123,081	862,536	21,197	841,339	4,687,672	257,945	2026	142	2,879
2027	423,309	(64,446)	160,026	327,729	257,945	175,539	433,484	761,213	120,593	881,805	19,545	862,260	4,916,655	257,945	2027	129	2,922
2028	443,871	(64,972)	184,728	324,115	257,945	185,490	443,435	767,549	126,586	894,135	18,172	875,963	5,130,776	257,945	2028	118	2,966
2029	449,576	(66,405)	171,547	344,435	257,945	189,249	447,194	791,628	125,849	917,477	16,922	900,554	5,333,402	257,945	2029	108	3,011
2030	447,903	(65,589)	142,887	370,606	257,945	185,694	443,639	814,245	121,897	936,142	15,279	920,863	5,524,119	257,945	2030	96	3,054
2031	472,357	(68,741)	179,168	361,930	146,766	150,153	296,919	658,849	129,869	788,717	13,237	775,481	5,671,953	146,766	2031	82	3,098
2032	499,944	(68,994)	212,421	356,517	146,766	151,607	298,373	654,890	137,412	792,302	11,838	780,464	5,808,905	146,766	2032	72	3,143
2033	512,366	(70,200)	214,491	368,074	146,766	151,587	298,353	666,426	139,235	805,662	7,997	797,665	5,937,744	146,766	2033	48	3,188
2034	500,983	(70,803)	156,995	414,791	146,766	146,773	293,539	708,330	130,802	839,132	7,022	832,111	6,061,457	146,766	2034	42	3,234
2035	528,155	(74,873)	189,797	413,231	146,766	159,660	306,426	719,657	137,829	857,486	5,778	851,708	6,178,014	146,766	2035	34	3,280
2036	540,885	(76,245)	199,891	417,239	146,766	162,670	309,436	726,675	141,181	867,856	3,992	863,865	6,286,832	146,766	2036	23	3,328
2037	569,449	(76,311)	229,485	416,275	146,766	165,417	312,183	728,459	147,803	876,261	1,015	875,246	6,388,316	146,766	2037	6	3,375
2038	572,520	(78,991)	213,521	437,990	146,766	168,207	314,973	752,964	146,863	899,827	(1,278)	901,105	6,484,488	146,766	2038	(7)	3,424
2039	598,882	(79,606)	237,192	441,297	146,766	171,989	318,755	760,052	152,311	912,363	(3,443)	915,806	6,574,457	146,766	2039	(19)	3,473
2040	605,615	(82,101)	223,815	463,901	146,766	352,653	499,419	963,320	151,596	1,114,916	(3,097)	1,118,013	6,675,555	146,766	2040	(17)	3,523
2011 Net Present Value																	
Period of 2011-2040	3,719,996	(603,725)	909,937	3,413,784	1,257,570	1,087,324	2,344,894	5,758,677	805,496	6,564,173	(111,382)	6,675,555					
Base Case O&M 2011-2040							614,444			614,444	0	614,444					
Utility Cost Present Value 2011-2040							2,959,338			7,178,617	(111,382)	7,290,000					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR High Band Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	8,345	8,183	6,802	0.36
2013	7,682	7,076	6,243	0.31
2014	9,403	7,763	5,623	0.32
2015	9,351	7,373	3,885	0.28
2016	4,097	5,155	2,092	0.15
2017	4,430	7,032	2,762	0.27
2018	4,358	7,456	2,794	0.28
2019	3,557	6,960	2,439	0.26
2020	4,573	7,486	1,750	0.27
2021	4,372	7,468	1,746	0.27
2022	4,559	7,217	1,685	0.25
2023	4,269	6,329	1,477	0.22
2024	3,655	6,942	1,626	0.25
2025	4,559	7,479	1,671	0.24
2026	3,917	7,749	1,746	0.27
2027	4,558	7,498	1,673	0.24
2028	3,884	7,770	1,750	0.27
2029	4,401	7,627	1,720	0.27
2030	4,332	7,290	1,621	0.23
2031	3,536	7,666	1,728	0.27
2032	4,572	8,008	1,802	0.27
2033	4,374	8,010	1,801	0.27
2034	4,558	7,428	1,649	0.23
2035	4,270	7,726	1,739	0.27
2036	3,658	7,812	1,759	0.27
2037	4,559	8,073	1,813	0.27
2038	3,917	7,918	1,781	0.27
2039	4,558	8,107	1,820	0.27
2040	3,886	7,965	1,789	0.27

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	128	2,034	1,906	6,900
2013	7,457	138	36	(102)	613	1,337	724	6,883
2014	7,469	139	17	(122)	166	1,604	1,438	6,894
2015	7,479	139	23	(116)	260	1,252	992	6,903
2016	7,488	139	19	(120)	2,368	760	(1,608)	6,911
2017	7,505	139	28	(111)	289	888	599	6,927
2018	7,536	139	37	(102)	141	1,183	1,042	6,955
2019	7,571	139	36	(103)	325	790	466	6,988
2020	7,604	139	34	(106)	163	1,182	1,019	7,019
2021	7,648	288	34	(254)	146	1,245	1,099	7,059
2022	7,695	288	34	(254)	337	1,082	744	7,102
2023	7,744	288	34	(254)	796	482	(314)	7,148
2024	7,798	289	34	(255)	360	722	362	7,198
2025	7,846	288	34	(254)	172	1,841	1,669	7,242
2026	7,896	288	34	(254)	123	2,026	1,903	7,288
2027	7,947	288	34	(254)	277	1,903	1,626	7,335
2028	7,999	289	34	(255)	144	1,984	1,840	7,383
2029	8,044	288	34	(254)	159	1,793	1,633	7,425
2030	8,093	288	34	(254)	492	1,779	1,288	7,470
2031	8,143	288	34	(254)	149	1,763	1,614	7,516
2032	8,195	289	34	(255)	82	2,005	1,923	7,564
2033	8,241	288	34	(254)	112	2,010	1,898	7,606
2034	8,289	288	34	(254)	393	1,676	1,283	7,651
2035	8,339	288	34	(254)	128	1,666	1,537	7,697
2036	8,389	289	34	(255)	125	1,710	1,585	7,743
2037	8,439	288	34	(254)	108	1,932	1,824	7,789
2038	8,488	288	34	(254)	103	1,721	1,619	7,835
2039	8,538	288	34	(254)	84	1,866	1,782	7,881
2040	8,589	289	34	(255)	128	1,739	1,612	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	Retrofit	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
			1- 407 MW			
2025	1,281	1,131	CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	1,131		407	1,538	13.4%
2033	1,372	1,123		407	1,530	11.6%
2034	1,378	1,123		407	1,530	11.1%
2035	1,389	1,127		407	1,534	10.5%
2036	1,399	1,127		407	1,534	9.7%
2037	1,415	1,127		407	1,534	8.4%
2038	1,427	1,127		407	1,534	7.5%
2039	1,438	1,127		407	1,534	6.7%
2040	1,436	1,127		407	1,534	6.9%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR High Band Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0	2011	0	958
2012	256,683	(21,746)	102,195	176,235	0	0	0	176,235	113,060	289,294	0	289,294	438,210	0	2012	0	388
2013	238,029	(31,187)	54,443	214,773	0	0	0	214,773	76,728	291,500	0	291,500	685,189	0	2013	0	161
2014	342,568	(39,475)	92,284	289,759	607	0	607	290,366	128,873	419,240	1,379	417,860	1,011,072	607	2014	45	595
2015	354,727	(46,478)	109,211	291,993	607	45,517	46,124	338,118	50,361	388,479	2,451	386,029	1,288,187	607	2015	31	1,507
2016	305,711	(49,149)	(10,081)	364,940	216,791	33,320	250,111	615,051	2,119	617,170	(16,179)	633,349	1,706,686	216,791	2016	(158)	1,973
2017	302,456	(46,763)	(28,556)	377,775	216,791	42,209	259,000	636,775	1,365	638,140	(10,354)	648,494	2,101,114	216,791	2017	(142)	1,397
2018	316,293	(47,022)	(17,814)	381,129	216,791	43,045	259,836	640,965	635	641,600	(9,066)	650,666	2,465,390	216,791	2018	(150)	1,165
2019	314,986	(46,560)	(35,545)	397,091	216,791	44,066	260,857	657,948	223	658,171	(11,858)	670,029	2,810,673	216,791	2019	(154)	1,480
2020	331,662	(48,086)	(16,144)	395,892	224,122	45,136	269,258	665,151	0	665,151	(14,642)	679,792	3,133,127	224,122	2020	(158)	1,777
2021	339,738	(62,542)	(13,705)	415,985	224,122	46,033	270,155	686,140	0	686,140	(16,982)	703,121	3,440,123	224,122	2021	(159)	2,056
2022	355,582	(63,889)	(14,071)	433,542	224,122	47,303	271,425	704,967	65,409	770,376	(20,551)	790,927	3,757,993	224,122	2022	(171)	2,315
2023	354,334	(63,717)	(43,873)	461,924	224,122	48,420	272,542	734,466	61,344	795,809	(23,527)	819,336	4,061,093	224,122	2023	(177)	2,553
2024	365,101	(64,312)	(44,101)	473,513	224,122	49,517	273,639	747,152	63,127	810,279	(26,674)	836,954	4,346,086	224,122	2024	(187)	2,744
2025	467,075	(58,639)	109,835	415,879	326,974	67,337	394,311	810,190	75,152	885,342	29,752	855,591	4,614,255	326,974	2025	202	2,836
2026	487,053	(59,960)	112,379	434,634	326,974	70,116	397,090	831,724	75,274	906,998	28,257	878,741	4,867,777	326,974	2026	189	2,879
2027	498,990	(60,464)	118,506	440,948	326,974	71,396	398,370	839,318	78,281	917,599	26,711	890,888	5,104,362	326,974	2027	176	2,922
2028	517,560	(61,827)	114,279	465,108	326,974	73,863	400,837	865,945	77,505	943,450	25,445	918,005	5,328,760	326,974	2028	165	2,966
2029	533,478	(63,502)	104,316	492,664	326,974	75,831	402,805	895,469	76,658	972,127	24,305	947,822	5,542,020	326,974	2029	155	3,011
2030	545,512	(63,528)	110,022	499,017	326,974	76,682	403,656	902,674	80,252	982,926	22,768	960,158	5,740,876	326,974	2030	143	3,054
2031	564,021	(65,252)	98,057	531,216	326,974	79,364	406,338	937,554	78,493	1,016,047	20,834	995,213	5,930,599	326,974	2031	129	3,098
2032	591,580	(65,591)	120,871	536,300	326,974	80,865	407,839	944,139	84,418	1,028,556	19,545	1,009,012	6,107,655	326,974	2032	120	3,143
2033	618,796	(66,832)	126,180	559,447	326,974	83,528	410,502	969,949	86,059	1,056,008	15,814	1,040,194	6,275,667	326,974	2033	95	3,188
2034	632,107	(68,099)	117,738	582,468	326,974	85,050	412,024	994,492	86,572	1,081,064	14,952	1,066,112	6,434,171	326,974	2034	89	3,234
2035	659,388	(70,075)	97,950	631,513	326,974	88,196	415,170	1,046,684	83,345	1,130,029	13,822	1,116,206	6,586,924	326,974	2035	81	3,280
2036	676,853	(71,252)	99,564	648,541	146,766	89,914	236,680	885,220	85,330	970,550	12,152	958,398	6,707,650	146,766	2036	70	3,328
2037	705,081	(71,563)	117,235	659,408	146,766	91,410	238,176	897,585	90,611	988,196	9,293	978,903	6,821,153	146,766	2037	53	3,375
2038	725,812	(73,611)	101,294	698,128	146,766	93,823	240,589	938,717	89,169	1,027,886	7,119	1,020,767	6,930,097	146,766	2038	40	3,424
2039	742,757	(74,116)	101,929	714,944	146,766	94,977	241,743	956,687	92,330	1,049,017	5,075	1,043,943	7,032,653	146,766	2039	28	3,473
2040	773,586	(75,928)	92,750	756,764	146,766	128,029	274,795	1,031,558	91,293	1,122,852	5,544	1,117,308	7,133,688	146,766	2040	30	3,523
2011 Net Present Value																	
Period of 2011-2040	4,243,555	(543,906)	547,664	4,239,797	1,812,173	454,129	2,266,302	6,506,099	621,257	7,127,355	(6,332)	7,133,688					
Base Case O&M 2011-2040							614,444			614,444	0	614,444					
Utility Cost Present Value 2011-2040							2,880,746			7,741,800	(6,332)	7,748,132					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR High Band Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	8,345	8,183	6,802	0.36
2013	7,682	7,076	6,243	0.31
2014	9,403	7,763	5,623	0.32
2015	9,351	8,112	6,025	0.32
2016	4,097	4,182	1,636	0.01
2017	4,430	4,025	1,811	0.01
2018	4,358	4,243	1,793	0.01
2019	3,557	4,020	1,504	0.01
2020	4,573	4,340	764	0.00
2021	4,372	4,319	761	0.00
2022	4,559	4,338	763	0.00
2023	4,269	4,015	694	0.00
2024	3,655	4,079	708	0.00
2025	4,559	4,794	805	0.00
2026	3,917	4,739	782	0.00
2027	4,558	4,867	813	0.00
2028	3,884	4,757	782	0.00
2029	4,401	4,646	756	0.00
2030	4,332	4,799	797	0.00
2031	3,536	4,634	754	0.00
2032	4,572	4,920	819	0.00
2033	4,374	4,951	820	0.00
2034	4,558	4,916	816	0.00
2035	4,270	4,672	755	0.00
2036	3,658	4,722	768	0.00
2037	4,559	4,949	820	0.00
2038	3,917	4,808	786	0.00
2039	4,558	4,914	816	0.00
2040	3,886	4,796	784	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	128	2,034	1,906	6,900
2013	7,457	138	36	(102)	613	1,337	724	6,883
2014	7,469	139	17	(122)	166	1,604	1,438	6,894
2015	7,479	139	23	(116)	142	1,933	1,792	6,903
2016	7,488	139	19	(120)	607	381	(226)	6,911
2017	7,505	139	28	(111)	779	286	(493)	6,927
2018	7,536	139	37	(102)	629	323	(306)	6,955
2019	7,571	139	36	(103)	859	276	(583)	6,988
2020	7,604	139	34	(106)	611	355	(256)	7,019
2021	7,648	288	34	(254)	590	387	(203)	7,059
2022	7,695	288	34	(254)	570	387	(183)	7,102
2023	7,744	288	34	(254)	851	272	(579)	7,148
2024	7,798	289	34	(255)	833	267	(565)	7,198
2025	7,846	288	34	(254)	488	1,436	948	7,242
2026	7,896	288	34	(254)	361	1,385	1,024	7,288
2027	7,947	288	34	(254)	436	1,484	1,048	7,335
2028	7,999	289	34	(255)	366	1,356	991	7,383
2029	8,044	288	34	(254)	386	1,251	865	7,425
2030	8,093	288	34	(254)	476	1,336	861	7,470
2031	8,143	288	34	(254)	491	1,226	734	7,516
2032	8,195	289	34	(255)	439	1,372	933	7,564
2033	8,241	288	34	(254)	352	1,335	983	7,606
2034	8,289	288	34	(254)	454	1,301	847	7,651
2035	8,339	288	34	(254)	422	1,093	671	7,697
2036	8,389	289	34	(255)	440	1,091	652	7,743
2037	8,439	288	34	(254)	420	1,203	783	7,789
2038	8,488	288	34	(254)	412	1,042	630	7,835
2039	8,538	288	34	(254)	505	1,095	590	7,881
2040	8,589	289	34	(255)	461	973	512	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR High Band Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	256,683	(21,746)	102,195	176,235	0	0	0	176,235	113,060	289,294	0	289,294	438,210	0
2013	238,029	(31,187)	54,443	214,773	0	0	0	214,773	76,728	291,500	0	291,500	685,189	0
2014	342,568	(39,475)	92,284	289,759	607	0	607	290,366	128,873	419,240	1,379	417,860	1,011,072	607
2015	318,242	(52,896)	52,989	318,150	607	(0)	607	318,757	42,898	361,655	(17,667)	379,322	1,283,373	607
2016	310,169	(49,494)	(4,278)	363,941	219,322	33,409	252,731	616,672	2,122	618,794	(3,454)	622,248	1,694,537	219,322
2017	305,901	(47,197)	(22,900)	376,998	219,322	42,217	261,539	638,538	1,367	639,905	(1,344)	641,249	2,084,558	219,322
2018	320,853	(47,698)	(11,624)	380,374	219,322	42,923	262,245	642,619	636	643,255	(1,554)	644,809	2,445,554	219,322
2019	319,622	(47,515)	(29,314)	396,450	219,322	43,674	262,996	659,446	224	659,670	(2,316)	661,986	2,786,693	219,322
2020	336,444	(48,689)	(9,971)	395,104	226,653	44,573	271,226	666,330	0	666,330	(3,183)	669,513	3,104,271	226,653
2021	344,606	(62,963)	(7,646)	415,215	226,653	45,279	271,932	687,147	0	687,147	(3,727)	690,874	3,405,920	226,653
2022	360,240	(64,391)	(7,677)	432,309	226,653	46,366	273,019	705,328	65,834	771,162	(5,627)	776,789	3,718,108	226,653
2023	359,562	(64,307)	(36,693)	460,561	226,653	47,315	273,968	734,529	61,814	796,343	(7,067)	803,410	4,015,315	226,653
2024	370,865	(65,033)	(36,204)	472,102	226,653	48,231	274,884	746,986	63,635	810,622	(8,983)	819,604	4,294,401	226,653
2025	471,137	(58,360)	115,653	413,845	329,505	65,738	395,243	809,087	75,505	884,592	48,041	836,551	4,556,603	329,505
2026	492,223	(59,625)	119,347	432,501	329,505	68,360	397,865	830,366	75,724	906,090	46,821	859,269	4,804,506	329,505
2027	503,504	(60,168)	124,842	438,829	329,505	69,396	398,901	837,730	78,669	916,400	45,553	870,847	5,035,769	329,505
2028	523,166	(61,456)	121,691	462,933	329,505	71,709	401,214	864,148	77,978	942,126	44,570	897,556	5,255,169	329,505
2029	539,731	(63,079)	112,388	490,422	329,505	73,519	403,024	893,446	77,177	970,623	43,717	926,906	5,463,723	329,505
2030	550,728	(63,099)	117,023	496,804	329,505	74,038	403,543	900,348	80,675	981,022	42,459	938,563	5,658,106	329,505
2031	570,456	(64,931)	106,438	528,948	329,505	76,543	406,048	934,997	79,001	1,013,998	40,809	973,189	5,843,631	329,505
2032	597,650	(65,114)	128,726	534,038	329,505	77,750	407,255	941,294	84,885	1,026,179	39,808	986,371	6,016,714	329,505
2033	626,222	(66,338)	135,454	557,106	329,505	80,187	409,692	966,798	86,617	1,053,415	36,369	1,017,047	6,180,987	329,505
2034	639,289	(67,680)	126,825	580,145	329,505	81,446	410,951	991,096	87,097	1,078,193	35,803	1,042,391	6,335,964	329,505
2035	667,426	(69,637)	107,797	629,266	329,505	84,370	413,875	1,043,141	83,919	1,127,059	34,974	1,092,086	6,485,416	329,505
2036	685,056	(70,743)	109,479	646,319	329,505	85,979	415,484	1,061,803	85,901	1,147,704	33,608	1,114,096	6,625,755	329,505
2037	713,391	(71,065)	127,312	657,144	329,505	87,347	416,852	1,073,996	91,175	1,165,171	31,058	1,134,113	6,757,254	329,505
2038	735,119	(73,094)	112,376	695,838	329,505	89,699	419,204	1,115,042	89,785	1,204,827	29,197	1,175,630	6,882,726	329,505
2039	751,298	(73,719)	112,313	712,704	329,505	90,668	420,173	1,132,877	92,880	1,225,757	27,472	1,198,285	7,000,446	329,505
2040	783,301	(75,517)	104,186	754,631	329,505	93,651	423,156	1,177,787	91,905	1,269,692	28,263	1,241,429	7,112,704	329,505
2011 Net Present Value														
Period of 2011-2040	4,256,306	(549,874)	558,053	4,248,127	1,927,380	408,673	2,336,053	6,584,180	617,823	7,202,003	89,299	7,112,704		
Base Case O&M 2011-2040							614,444			614,444	0	614,444		
Utility Cost Present Value 2011-2040							2,950,498			7,816,447	89,299	7,727,148		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(34)	1,973
2017	(18)	1,397
2018	(26)	1,165
2019	(30)	1,480
2020	(34)	1,777
2021	(35)	2,056
2022	(47)	2,315
2023	(53)	2,553
2024	(63)	2,744
2025	326	2,836
2026	313	2,879
2027	300	2,922
2028	289	2,966
2029	279	3,011
2030	267	3,054
2031	253	3,098
2032	244	3,143
2033	219	3,188
2034	213	3,234
2035	205	3,280
2036	194	3,328
2037	177	3,375
2038	164	3,424
2039	152	3,473
2040	154	3,523

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR High Band Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	8,345	8,183	6,802	0.36
2013	7,682	7,076	6,243	0.31
2014	9,403	7,763	5,623	0.32
2015	9,351	7,373	3,885	0.28
2016	4,097	4,215	1,639	0.01
2017	4,430	4,055	1,814	0.01
2018	4,358	4,274	1,796	0.01
2019	3,557	4,051	1,507	0.01
2020	4,573	4,371	767	0.00
2021	4,372	4,349	764	0.00
2022	4,559	4,366	766	0.00
2023	4,269	4,046	697	0.00
2024	3,655	4,112	711	0.00
2025	4,559	4,817	808	0.00
2026	3,917	4,767	785	0.00
2027	4,558	4,891	816	0.00
2028	3,884	4,786	785	0.00
2029	4,401	4,677	759	0.00
2030	4,332	4,824	800	0.00
2031	3,536	4,664	758	0.00
2032	4,572	4,947	821	0.00
2033	4,374	4,983	823	0.00
2034	4,558	4,946	820	0.00
2035	4,270	4,704	758	0.00
2036	3,658	4,753	771	0.00
2037	4,559	4,980	823	0.00
2038	3,917	4,841	790	0.00
2039	4,558	4,944	819	0.00
2040	3,886	4,828	788	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	128	2,034	1,906	6,900
2013	7,457	138	36	(102)	613	1,337	724	6,883
2014	7,469	139	17	(122)	166	1,604	1,438	6,894
2015	7,479	139	23	(116)	260	1,252	992	6,903
2016	7,488	139	19	(120)	564	425	(140)	6,911
2017	7,505	139	28	(111)	728	317	(411)	6,927
2018	7,536	139	37	(102)	583	361	(223)	6,955
2019	7,571	139	36	(103)	806	308	(498)	6,988
2020	7,604	139	34	(106)	569	396	(173)	7,019
2021	7,648	288	34	(254)	551	427	(124)	7,059
2022	7,695	288	34	(254)	534	422	(112)	7,102
2023	7,744	288	34	(254)	799	301	(498)	7,148
2024	7,798	289	34	(255)	775	299	(476)	7,198
2025	7,846	288	34	(254)	486	1,493	1,007	7,242
2026	7,896	288	34	(254)	352	1,451	1,099	7,288
2027	7,947	288	34	(254)	435	1,547	1,112	7,335
2028	7,999	289	34	(255)	353	1,421	1,068	7,383
2029	8,044	288	34	(254)	368	1,316	948	7,425
2030	8,093	288	34	(254)	471	1,397	926	7,470
2031	8,143	288	34	(254)	474	1,289	815	7,516
2032	8,195	289	34	(255)	430	1,435	1,004	7,564
2033	8,241	288	34	(254)	334	1,404	1,069	7,606
2034	8,289	288	34	(254)	438	1,366	927	7,651
2035	8,339	288	34	(254)	399	1,156	756	7,697
2036	8,389	289	34	(255)	417	1,153	736	7,743
2037	8,439	288	34	(254)	404	1,269	865	7,789
2038	8,488	288	34	(254)	389	1,109	720	7,835
2039	8,538	288	34	(254)	488	1,156	668	7,881
2040	8,589	289	34	(255)	437	1,036	599	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

[A] Total East SO2 Excludes Cardinal 2&3 Emissions

[B] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR High Band Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	256,683	(21,746)	102,195	176,235	0	0	0	176,235	113,060	289,294	0	289,294	438,210	0
2013	238,029	(31,187)	54,443	214,773	0	0	0	214,773	76,728	291,500	0	291,500	685,189	0
2014	342,568	(39,475)	92,284	289,759	607	0	607	290,366	128,873	419,240	1,379	417,860	1,011,072	607
2015	318,242	(52,896)	52,989	318,150	607	(0)	607	318,757	42,898	361,655	(17,667)	379,322	1,283,373	607
2016	86,327	(42,219)	(295,271)	423,817	36,583	0	36,583	460,400	1,947	462,347	(96,221)	558,568	1,652,458	36,583
2017	78,493	(38,795)	(312,073)	429,361	36,583	0	36,583	465,944	1,243	467,187	(67,034)	534,221	1,977,383	36,583
2018	86,740	(37,900)	(308,061)	432,700	36,583	0	36,583	469,283	574	469,858	(56,319)	526,177	2,271,963	36,583
2019	80,211	(38,237)	(329,049)	447,497	36,583	0	36,583	484,080	200	484,279	(71,879)	556,159	2,558,566	36,583
2020	336,444	(48,689)	(9,971)	395,104	238,249	44,573	282,822	677,926	0	677,926	(3,183)	681,109	2,881,645	238,249
2021	344,606	(62,963)	(7,646)	415,215	238,249	45,279	283,528	698,743	0	698,743	(3,727)	702,470	3,188,357	238,249
2022	360,240	(64,391)	(7,677)	432,309	238,249	46,366	284,615	716,924	65,834	782,758	(5,627)	788,385	3,505,205	238,249
2023	359,562	(64,307)	(36,693)	460,561	238,249	47,315	285,564	746,125	61,814	807,939	(7,067)	815,006	3,806,702	238,249
2024	370,865	(65,033)	(36,204)	472,102	238,249	48,231	286,480	758,582	63,635	822,218	(8,983)	831,200	4,089,737	238,249
2025	471,137	(58,360)	115,653	413,845	341,101	65,738	406,839	820,683	75,505	896,188	48,041	848,147	4,355,573	341,101
2026	492,223	(59,625)	119,347	432,501	341,101	68,360	409,461	841,962	75,724	917,686	46,821	870,865	4,606,822	341,101
2027	503,504	(60,168)	124,842	438,829	341,101	69,396	410,497	849,326	78,669	927,996	45,553	882,443	4,841,164	341,101
2028	523,166	(61,458)	121,691	462,933	341,101	71,709	412,810	875,744	77,978	953,722	44,570	909,152	5,063,398	341,101
2029	539,731	(63,079)	112,388	490,422	341,101	73,519	414,620	905,042	77,177	982,219	43,717	938,502	5,274,562	341,101
2030	550,728	(63,099)	117,023	496,804	341,101	74,038	415,139	911,944	80,675	992,618	42,459	950,159	5,471,346	341,101
2031	570,456	(64,931)	106,438	528,948	341,101	76,543	417,644	946,593	79,001	1,025,594	40,809	984,785	5,659,082	341,101
2032	597,650	(65,114)	128,726	534,038	341,101	77,750	418,851	952,890	84,885	1,037,775	39,808	997,967	5,834,200	341,101
2033	626,222	(66,338)	135,454	557,106	341,101	80,187	421,288	978,394	86,617	1,065,011	36,369	1,028,643	6,000,346	341,101
2034	639,289	(67,680)	126,825	580,145	341,101	81,446	422,547	1,002,692	87,097	1,089,789	35,803	1,053,987	6,157,047	341,101
2035	667,426	(69,637)	107,797	629,266	341,101	84,370	425,471	1,054,737	83,919	1,138,655	34,974	1,103,682	6,308,086	341,101
2036	685,056	(70,743)	109,479	646,319	341,101	85,979	427,080	1,073,399	85,901	1,159,300	33,608	1,125,692	6,449,886	341,101
2037	713,391	(71,065)	127,312	657,144	341,101	87,347	428,448	1,085,592	91,175	1,176,767	31,058	1,145,709	6,582,729	341,101
2038	735,119	(73,094)	112,376	695,838	341,101	89,699	430,800	1,126,638	89,785	1,216,423	29,197	1,187,226	6,709,439	341,101
2039	751,298	(73,719)	112,313	712,704	341,101	90,668	431,769	1,144,473	92,880	1,237,353	27,472	1,209,881	6,828,297	341,101
2040	783,301	(75,517)	104,186	754,631	341,101	93,651	434,752	1,189,383	91,905	1,281,288	28,263	1,253,025	6,941,604	341,101
2011 Net Present Value														
Period of 2011-2040	3,715,032	(529,690)	(130,418)	4,375,140	1,556,036	314,383	1,870,419	6,245,559	617,584	6,863,144	(78,460)	6,941,604		
Base Case O&M 2011-2040							614,444			614,444	0	614,444		
Utility Cost Present Value 2011-2040							2,484,864			7,477,588	(78,460)	7,556,049		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(922)	1,397
2018	(930)	1,165
2019	(934)	1,480
2020	(34)	1,777
2021	(35)	2,056
2022	(47)	2,315
2023	(53)	2,553
2024	(63)	2,744
2025	326	2,836
2026	313	2,879
2027	300	2,922
2028	289	2,966
2029	279	3,011
2030	267	3,054
2031	253	3,098
2032	244	3,143
2033	219	3,188
2034	213	3,234
2035	205	3,280
2036	194	3,328
2037	177	3,375
2038	164	3,424
2039	152	3,473
2040	154	3,523

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR High Band Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	8,345	8,183	6,802	0.36
2013	7,682	7,076	6,243	0.31
2014	9,403	7,763	5,623	0.32
2015	9,351	7,373	3,885	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	4,371	767	0.00
2021	4,372	4,349	764	0.00
2022	4,559	4,366	766	0.00
2023	4,269	4,046	697	0.00
2024	3,655	4,112	711	0.00
2025	4,559	4,817	806	0.00
2026	3,917	4,767	785	0.00
2027	4,558	4,891	816	0.00
2028	3,884	4,786	785	0.00
2029	4,401	4,677	759	0.00
2030	4,332	4,824	800	0.00
2031	3,536	4,664	758	0.00
2032	4,572	4,947	821	0.00
2033	4,374	4,983	823	0.00
2034	4,558	4,946	820	0.00
2035	4,270	4,704	758	0.00
2036	3,658	4,753	771	0.00
2037	4,559	4,980	823	0.00
2038	3,917	4,841	790	0.00
2039	4,558	4,944	819	0.00
2040	3,886	4,828	788	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	128	2,034	1,906	6,900
2013	7,457	138	36	(102)	613	1,337	724	6,883
2014	7,469	139	17	(122)	166	1,604	1,438	6,894
2015	7,479	139	23	(116)	260	1,252	992	6,903
2016	7,488	139	19	(120)	4,596		(4,596)	6,911
2017	7,505	139	28	(111)	4,769		(4,769)	6,927
2018	7,536	139	37	(102)	4,573		(4,573)	6,955
2019	7,571	139	36	(103)	4,852		(4,852)	6,988
2020	7,604	139	34	(106)	569	396	(173)	7,019
2021	7,648	288	34	(254)	551	427	(124)	7,059
2022	7,695	288	34	(254)	534	422	(112)	7,102
2023	7,744	288	34	(254)	799	301	(498)	7,148
2024	7,798	289	34	(255)	775	299	(476)	7,198
2025	7,846	288	34	(254)	486	1,493	1,007	7,242
2026	7,896	288	34	(254)	352	1,451	1,099	7,288
2027	7,947	288	34	(254)	435	1,547	1,112	7,335
2028	7,999	289	34	(255)	353	1,421	1,068	7,383
2029	8,044	288	34	(254)	368	1,316	948	7,425
2030	8,093	288	34	(254)	471	1,397	926	7,470
2031	8,143	288	34	(254)	474	1,289	815	7,516
2032	8,195	289	34	(255)	430	1,435	1,004	7,564
2033	8,241	288	34	(254)	334	1,404	1,069	7,606
2034	8,289	288	34	(254)	438	1,366	927	7,651
2035	8,339	288	34	(254)	399	1,156	756	7,697
2036	8,389	289	34	(255)	417	1,153	736	7,743
2037	8,439	288	34	(254)	404	1,269	865	7,789
2038	8,488	288	34	(254)	389	1,109	720	7,835
2039	8,538	288	34	(254)	488	1,156	668	7,881
2040	8,589	289	34	(255)	437	1,036	599	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	1,288	1 -904 MW NGCC,	0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FT_CSAPR High Band Commodity Pricing

	Optimal Plan Cost Summary ($000)				Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0	2011	0	958
2012	256,683	(21,746)	102,195	176,235	0	0	0	176,235	113,060	289,294	0	289,294	438,210	0	2012	0	388
2013	238,029	(31,187)	54,443	214,773	0	0	0	214,773	76,728	291,500	0	291,500	685,189	0	2013	0	161
2014	342,568	(39,475)	92,284	289,759	607	0	607	290,366	128,873	419,240	1,379	417,860	1,011,072	607	2014	45	595
2015	318,242	(52,898)	52,989	318,150	607	(0)	607	318,757	42,898	361,655	(17,667)	379,322	1,283,373	607	2015	(225)	1,507
2016	86,327	(42,219)	(295,271)	423,817	36,583	0	36,583	460,400	1,947	462,347	(96,221)	558,568	1,652,458	36,583	2016	(938)	1,973
2017	78,493	(38,795)	(312,073)	429,361	36,583	0	36,583	465,944	1,243	467,187	(67,034)	534,221	1,977,383	36,583	2017	(922)	1,397
2018	86,740	(37,900)	(308,061)	432,700	36,583	0	36,583	469,283	574	469,858	(56,319)	526,177	2,271,963	36,583	2018	(930)	1,165
2019	80,211	(38,237)	(329,049)	447,497	36,583	0	36,583	484,080	200	484,279	(71,879)	556,159	2,558,566	36,583	2019	(934)	1,480
2020	93,815	(38,583)	(316,571)	448,968	43,914	0	43,914	492,882	0	492,882	(86,717)	579,600	2,833,495	43,914	2020	(938)	1,777
2021	95,319	(52,481)	(319,769)	467,569	43,914	0	43,914	511,483	0	511,483	(100,355)	611,838	3,100,635	43,914	2021	(939)	2,056
2022	96,880	(54,703)	(364,869)	516,452	43,914	0	43,914	560,366	41,846	602,213	(114,427)	716,640	3,388,649	43,914	2022	(951)	2,315
2023	88,201	(54,670)	(404,268)	547,139	43,914	0	43,914	591,053	37,415	628,469	(127,066)	755,534	3,668,146	43,914	2023	(957)	2,553
2024	90,087	(55,095)	(412,499)	557,680	43,914	0	43,914	601,594	38,892	640,487	(137,958)	778,445	3,933,217	43,914	2024	(967)	2,744
2025	471,137	(58,360)	115,653	413,845	369,468	65,738	435,206	849,050	75,505	924,555	48,041	876,514	4,207,944	369,468	2025	326	2,836
2026	492,223	(59,625)	119,347	432,501	369,468	68,360	437,828	870,329	75,724	946,053	46,821	899,232	4,467,377	369,468	2026	313	2,879
2027	503,504	(60,168)	124,842	438,829	369,468	69,396	438,864	877,693	78,669	956,363	45,553	910,810	4,709,252	369,468	2027	300	2,922
2028	523,166	(61,458)	121,691	462,933	369,468	71,709	441,177	904,111	77,978	982,089	44,570	937,519	4,938,421	369,468	2028	289	2,966
2029	539,731	(63,079)	112,388	490,422	369,468	73,519	442,987	933,409	77,177	1,010,586	43,717	966,869	5,155,967	369,468	2029	279	3,011
2030	550,728	(63,099)	117,023	496,804	369,468	74,038	443,506	940,311	80,675	1,020,985	42,459	978,526	5,358,626	369,468	2030	257	3,054
2031	570,456	(64,931)	106,438	528,948	369,468	76,543	446,011	974,960	79,001	1,053,961	40,809	1,013,152	5,551,770	369,468	2031	253	3,098
2032	597,650	(65,114)	128,726	534,038	369,468	77,750	447,218	981,257	84,885	1,066,142	39,808	1,026,334	5,731,866	369,468	2032	244	3,143
2033	626,222	(66,338)	135,454	557,106	369,468	80,187	449,655	1,006,761	86,617	1,093,378	36,369	1,057,010	5,902,593	369,468	2033	219	3,188
2034	639,289	(67,680)	126,825	580,145	369,468	81,446	450,914	1,031,059	87,097	1,118,156	35,803	1,082,354	6,063,511	369,468	2034	213	3,234
2035	667,426	(69,637)	107,797	629,266	369,468	84,370	453,838	1,083,104	83,919	1,167,022	34,974	1,132,049	6,218,433	369,468	2035	205	3,280
2036	685,056	(70,743)	109,479	646,319	369,468	85,979	455,447	1,101,766	85,901	1,187,667	33,608	1,154,059	6,363,806	369,468	2036	194	3,328
2037	713,391	(71,065)	127,312	657,144	369,468	87,347	456,815	1,113,959	91,175	1,205,134	31,058	1,174,076	6,499,938	369,468	2037	177	3,375
2038	735,119	(73,094)	112,376	695,838	369,468	89,699	459,167	1,155,005	89,785	1,244,790	29,197	1,215,593	6,629,676	369,468	2038	164	3,424
2039	751,298	(73,719)	112,313	712,704	369,468	90,668	460,136	1,172,840	92,880	1,265,720	27,472	1,238,248	6,751,321	369,468	2039	152	3,473
2040	783,301	(75,517)	104,186	754,631	369,468	93,651	463,119	1,217,750	91,905	1,309,655	28,263	1,281,392	6,867,193	369,468	2040	154	3,523
2011 Net Present Value																	
Period of 2011-2040	3,189,263	(509,477)	(819,795)	4,518,535	1,244,947	220,909	1,465,856	5,984,391	590,493	6,574,884	(292,309)	6,867,193					
Base Case O&M 2011-2040							614,444			614,444	0	614,444					
Utility Cost Present Value 2011-2040							2,080,300			7,189,328	(292,309)	7,481,637					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added *FT_CSAPR High Band Commodity Pricing*

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	8,345	8,183	6,802	0.36
2013	7,682	7,076	6,243	0.31
2014	9,403	7,763	5,623	0.32
2015	9,351	7,373	3,885	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	2,783	597	0.00
2021	4,372	2,775	595	0.00
2022	4,559	2,775	595	0.00
2023	4,269	2,449	525	0.00
2024	3,655	2,513	539	0.00
2025	4,559	4,817	808	0.00
2026	3,917	4,767	785	0.00
2027	4,558	4,891	816	0.00
2028	3,884	4,786	785	0.00
2029	4,401	4,677	759	0.00
2030	4,332	4,824	800	0.00
2031	3,536	4,664	758	0.00
2032	4,572	4,947	821	0.00
2033	4,374	4,983	823	0.00
2034	4,558	4,946	820	0.00
2035	4,270	4,704	758	0.00
2036	3,658	4,753	771	0.00
2037	4,559	4,980	823	0.00
2038	3,917	4,841	790	0.00
2039	4,558	4,944	819	0.00
2040	3,886	4,828	788	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	128	2,034	1,906	6,900
2013	7,457	138	36	(102)	613	1,337	724	6,883
2014	7,469	139	17	(122)	166	1,604	1,438	6,894
2015	7,479	139	23	(116)	260	1,252	992	6,903
2016	7,488	139	19	(120)	4,596		(4,596)	6,911
2017	7,505	139	28	(111)	4,769		(4,769)	6,927
2018	7,536	139	37	(102)	4,573		(4,573)	6,955
2019	7,571	139	36	(103)	4,852		(4,852)	6,988
2020	7,604	139	34	(106)	4,552		(4,552)	7,019
2021	7,648	288	34	(254)	4,462		(4,462)	7,059
2022	7,695	288	34	(254)	4,481		(4,481)	7,102
2023	7,744	288	34	(254)	4,885		(4,885)	7,148
2024	7,798	289	34	(255)	4,873		(4,873)	7,198
2025	7,846	288	34	(254)	486	1,493	1,007	7,242
2026	7,896	288	34	(254)	352	1,451	1,099	7,288
2027	7,947	288	34	(254)	435	1,547	1,112	7,335
2028	7,999	289	34	(255)	353	1,421	1,068	7,383
2029	8,044	288	34	(254)	368	1,316	948	7,425
2030	8,093	288	34	(254)	471	1,397	926	7,470
2031	8,143	288	34	(254)	474	1,289	815	7,516
2032	8,195	289	34	(255)	430	1,435	1,004	7,564
2033	8,241	288	34	(254)	334	1,404	1,069	7,606
2034	8,289	288	34	(254)	438	1,366	927	7,651
2035	8,339	288	34	(254)	399	1,156	756	7,697
2036	8,389	289	34	(255)	417	1,153	736	7,743
2037	8,439	288	34	(254)	404	1,269	865	7,789
2038	8,488	288	34	(254)	369	1,109	720	7,835
2039	8,538	288	34	(254)	488	1,156	668	7,881
2040	8,589	289	34	(255)	437	1,036	599	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,303	*1- 407 MW* CC,1 -904 MW NGCC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

Big Sandy Unit 2 under: "Fleet Transition-LOWER Band" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	**'BASE' Option #1** BS2 DFGD Retrofit 6/2016	**Option #2** (1) RK Retires 1/2016 with (Brownfield) CC Replacement	**Option #3** (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	**Option #4A** (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	**Option #4B** (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013				45 MW- ICAP	45 MW- ICAP
2014				225 MW- ICAP	225 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	938 MW- ICAP	938 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	922 MW- ICAP	922 MW- ICAP
2017				930 MW- ICAP	930 MW- ICAP
2018				934 MW- ICAP	934 MW- ICAP
2019				1 -904 MW NGCC	938 MW- ICAP
2020					939 MW- ICAP
2021					951 MW- ICAP
2022					957 MW- ICAP
2023					967 MW- ICAP
2024					1 -904 MW NGCC, 1-
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	407 MW CC
2026 ~ 2040					
Life-Cycle Analysis Period (2011-2040) ($000)					
CPW of Revenue Requirements	6,466,223	6,822,787	6,748,205	6,494,581	6,182,746
Less: ICAP Revenue	(108,542)	71,203	(9,322)	(101,059)	(273,169)
CPW of Revenue Requirements, Net	6,574,765	6,751,584	6,757,528	6,595,640	6,455,915
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		356,564	281,982	28,358	(283,477)
Less: ICAP / Pool Revenue		179,746	99,220	7,483	(164,626)
CPW of Revenue Requirements, Net		176,819	182,762	20,875	(118,850)
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year) *RETROFIT Cost Recovery*		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		214,019	219,962	58,075	(81,650)

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

Inclusive of:
1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Big Sandy 2 UD Analysis Under FT_CSAPR Low Band Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life	***BS1 Repower 20 yr book life***	***NGCC Replacement***	***Market to 2020***	***Market to 2025***
2011				0 MW- ICAP	0 MW- ICAP
2012				0 MW- ICAP	0 MW- ICAP
2013				0 MW- ICAP	0 MW- ICAP
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire		Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	**Big Sandy 2 Retrofit**	**Big Sandy 1 Retire 1 -780 MW Repower,**	**1 -904 MW NGCC**	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				**1 -904 MW NGCC**	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1 -904 MW NGCC, 1-407 MW CC**
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
FTCA_CSAPR Low Band					
CPW	6,466,223	6,748,205	6,822,787	6,494,581	6,182,746
ICAP Revenue	(108,542)	(9,322)	71,203	(101,059)	(273,169)
Total	$6,574,765	$6,757,528	$6,751,584	$6,595,640	$6,455,915
Cost Over Retrofit		$182,762	$176,819	$20,875	($118,850)

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR Low Band Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	192,631	(12,788)	40,914	164,505	0	0	0	164,505	7,418	171,923	0	171,923	171,923	0
2012	244,613	(20,650)	87,015	178,248	0	0	0	178,248	60,605	238,853	0	238,853	391,780	0
2013	240,839	(29,973)	48,672	222,140	0	0	0	222,140	31,233	253,373	0	253,373	606,454	0
2014	250,619	(37,859)	55,811	232,667	607	0	607	233,274	81,027	314,301	1,379	312,922	850,498	607
2015	232,418	(48,543)	25,350	255,612	607	0	607	256,219	16,156	272,375	(17,667)	290,041	1,058,708	607
2016	149,933	(47,265)	(79,565)	276,763	147,762	76,448	224,210	500,973	1,779	502,751	(96,221)	598,972	1,454,491	147,762
2017	213,019	(52,849)	26,469	239,398	147,762	137,375	285,137	524,535	924	525,459	(14,943)	540,402	1,763,175	147,762
2018	229,414	(53,604)	48,300	234,718	147,762	149,123	296,885	531,603	251	531,853	(12,363)	544,216	2,087,854	147,762
2019	217,808	(55,992)	19,796	254,003	147,762	139,255	287,017	541,020	130	541,150	(13,405)	554,555	2,373,630	147,762
2020	239,460	(57,050)	46,056	250,454	155,093	140,048	295,141	545,595	0	545,595	(15,909)	561,504	2,639,975	155,093
2021	243,696	(71,651)	50,990	264,357	155,093	143,469	298,562	562,919	0	562,919	(17,901)	580,820	2,893,573	155,093
2022	236,458	(72,760)	42,776	266,442	155,093	143,847	298,940	565,382	108,410	673,792	(20,997)	694,789	3,172,805	155,093
2023	212,512	(71,525)	(24,077)	308,114	155,093	140,269	295,362	603,477	96,242	699,719	(23,536)	723,254	3,440,360	155,093
2024	237,197	(75,514)	18,877	293,834	155,093	150,037	305,130	598,963	106,896	705,859	(26,281)	732,141	3,689,663	155,093
2025	312,142	(60,294)	119,098	253,338	257,945	160,824	418,769	672,107	108,859	780,966	18,316	762,650	3,928,702	257,945
2026	331,683	(61,669)	141,518	251,835	257,945	170,443	428,388	680,223	115,020	795,242	17,525	777,717	4,153,078	257,945
2027	325,171	(62,643)	116,363	271,451	257,945	168,521	426,466	697,917	111,976	809,893	16,415	793,478	4,363,794	257,945
2028	346,882	(63,271)	141,915	268,238	257,945	178,952	436,897	705,135	118,537	823,672	15,363	808,309	4,561,378	257,945
2029	350,775	(64,611)	131,185	284,201	257,945	183,692	441,637	725,838	119,098	844,936	14,282	830,654	4,748,276	257,945
2030	340,855	(63,789)	96,734	307,910	257,945	178,185	436,130	744,040	112,844	856,884	12,653	844,231	4,923,122	257,945
2031	367,123	(66,216)	133,279	300,061	146,766	144,386	291,152	591,212	122,920	714,133	10,949	703,184	5,057,175	146,766
2032	380,023	(66,313)	145,140	301,196	146,766	143,001	289,767	590,963	127,171	718,134	9,781	708,353	5,181,473	146,766
2033	387,022	(67,376)	142,562	311,837	146,766	142,710	289,476	601,313	128,799	730,112	6,599	723,513	5,298,334	146,766
2034	379,546	(67,879)	104,794	342,631	146,766	139,879	286,645	629,276	122,689	751,966	5,788	746,178	5,409,272	146,766
2035	403,391	(70,776)	129,866	344,301	146,766	153,054	299,820	644,121	130,178	774,299	4,757	769,542	5,514,584	146,766
2036	405,262	(71,756)	127,073	349,945	146,766	154,264	301,030	650,974	131,508	782,483	3,283	779,200	5,612,737	146,766
2037	420,356	(71,862)	137,264	354,955	146,766	154,997	301,763	656,718	135,910	792,628	834	791,794	5,704,545	146,766
2038	428,424	(74,004)	134,409	368,018	146,766	160,246	307,012	675,030	137,866	812,896	(1,049)	813,945	5,791,415	146,766
2039	437,094	(74,365)	134,715	376,745	146,766	160,974	307,740	684,484	139,912	824,397	(2,821)	827,218	5,872,681	146,766
2040	440,870	(76,293)	124,072	393,092	146,766	342,152	488,918	882,010	139,942	1,021,952	(2,535)	1,024,486	5,965,322	146,766
2011 Net Present Value														
Period of 2011-2040	2,981,188	(574,498)	654,836	2,900,850	1,257,570	1,064,161	2,321,731	5,222,581	634,199	5,856,779	(108,542)	5,965,322		
Base Case O&M 2011-2040							609,444			609,444	0	609,444		
Utility Cost Present Value 2011-2040							2,931,175			6,466,223	(108,542)	6,574,765		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(178)	1,616
2018	(189)	1,258
2019	(197)	1,306
2020	(206)	1,488
2021	(206)	1,671
2022	(218)	1,853
2023	(224)	2,017
2024	(234)	2,159
2025	155	2,279
2026	142	2,380
2027	129	2,454
2028	118	2,508
2029	108	2,541
2030	96	2,529
2031	82	2,562
2032	72	2,596
2033	48	2,631
2034	42	2,665
2035	34	2,701
2036	23	2,736
2037	6	2,772
2038	(7)	2,809
2039	(19)	2,846
2040	(17)	2,884

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR Low Band Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,310	6,815	0.34
2013	11,885	7,487	6,303	0.28
2014	4,397	7,056	5,741	0.34
2015	7,161	6,772	3,153	0.28
2016	4,097	5,139	2,088	0.15
2017	4,430	6,997	2,754	0.27
2018	4,358	7,427	2,787	0.28
2019	3,557	6,921	2,429	0.26
2020	4,573	7,447	1,741	0.27
2021	4,372	7,428	1,736	0.27
2022	4,559	7,189	1,678	0.25
2023	4,269	6,299	1,470	0.22
2024	3,655	6,907	1,617	0.25
2025	4,559	6,945	1,511	0.20
2026	3,917	7,241	1,586	0.22
2027	4,558	6,962	1,516	0.20
2028	3,884	7,276	1,596	0.23
2029	4,401	7,218	1,592	0.23
2030	4,332	6,748	1,461	0.19
2031	3,536	7,256	1,597	0.23
2032	4,572	7,411	1,626	0.22
2033	4,374	7,409	1,626	0.22
2034	4,558	6,967	1,512	0.20
2035	4,270	7,297	1,607	0.24
2036	3,658	7,277	1,601	0.23
2037	4,559	7,424	1,629	0.23
2038	3,917	7,433	1,637	0.24
2039	4,558	7,447	1,636	0.23
2040	3,886	7,352	1,618	0.23

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	91	2,065	1,974	6,900
2013	7,457	138	36	(102)	394	1,455	1,060	6,883
2014	7,469	139	17	(122)	671	1,426	755	6,894
2015	7,479	139	23	(116)	486	862	376	6,903
2016	7,488	139	19	(120)	2,373	733	(1,640)	6,911
2017	7,505	139	28	(111)	310	854	544	6,927
2018	7,536	139	37	(102)	154	1,150	996	6,955
2019	7,571	139	36	(103)	351	755	404	6,988
2020	7,604	139	34	(106)	173	1,132	959	7,019
2021	7,640	288	34	(254)	160	1,196	1,036	7,059
2022	7,695	288	34	(254)	350	1,053	703	7,102
2023	7,744	288	34	(254)	817	458	(359)	7,148
2024	7,798	289	34	(255)	385	692	307	7,198
2025	7,846	288	34	(254)	331	1,717	1,386	7,242
2026	7,896	288	34	(254)	236	1,958	1,722	7,288
2027	7,947	288	34	(254)	422	1,725	1,303	7,335
2028	7,999	289	34	(255)	270	1,917	1,647	7,383
2029	8,044	288	34	(254)	280	1,755	1,476	7,425
2030	8,093	288	34	(254)	661	1,627	966	7,470
2031	8,143	288	34	(254)	301	1,781	1,480	7,516
2032	8,195	289	34	(255)	315	1,881	1,566	7,564
2033	8,241	288	34	(254)	311	1,830	1,519	7,606
2034	8,289	288	34	(254)	587	1,613	1,026	7,651
2035	8,339	288	34	(254)	316	1,660	1,343	7,697
2036	8,389	289	34	(255)	376	1,630	1,254	7,743
2037	8,439	288	34	(254)	399	1,744	1,345	7,789
2038	8,488	288	34	(254)	300	1,626	1,327	7,835
2039	8,538	288	34	(254)	400	1,664	1,264	7,881
2040	8,589	289	34	(255)	411	1,540	1,129	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	Retrofit	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	1,131		407	1,538	13.4%
2033	1,372	1,123		407	1,530	11.6%
2034	1,378	1,123		407	1,530	11.1%
2035	1,389	1,127		407	1,534	10.5%
2036	1,399	1,127		407	1,534	9.7%
2037	1,415	1,127		407	1,534	8.4%
2038	1,427	1,127		407	1,534	7.5%
2039	1,438	1,127		407	1,534	6.7%
2040	1,436	1,127		407	1,534	6.9%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR Low Band Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	244,613	(20,650)	87,015	178,248	0	0	0	178,248	60,605	238,853	0	238,853	391,780	0
2013	240,839	(29,973)	48,672	222,140	0	0	0	222,140	31,233	253,373	0	253,373	606,454	0
2014	250,619	(37,859)	55,811	232,667	607	0	607	233,274	81,027	314,301	1,379	312,922	850,498	607
2015	263,341	(44,481)	76,097	231,725	607	45,867	46,474	278,199	19,727	297,926	2,451	295,475	1,062,608	607
2016	236,574	(47,509)	(7,419)	291,502	216,791	33,390	250,181	541,682	1,337	543,020	(16,179)	559,199	1,432,111	216,791
2017	235,227	(45,858)	(20,502)	301,587	216,791	42,413	259,204	560,791	598	561,389	(11,973)	573,363	1,780,842	216,791
2018	245,872	(46,069)	(11,213)	303,153	216,791	43,255	260,046	563,199	159	563,358	(9,792)	573,151	2,101,720	216,791
2019	243,764	(45,653)	(26,490)	315,907	216,791	44,246	261,037	576,944	82	577,026	(10,469)	587,494	2,404,471	216,791
2020	257,612	(46,809)	(10,731)	315,153	224,122	45,322	269,444	584,597	0	584,597	(12,260)	596,857	2,687,586	224,122
2021	263,638	(61,111)	(8,799)	333,548	224,122	46,206	270,328	603,876	0	603,876	(13,804)	617,679	2,957,276	224,122
2022	277,144	(63,150)	(6,180)	346,473	224,122	47,628	271,750	618,223	65,827	684,050	(16,453)	700,503	3,238,805	224,122
2023	276,686	(63,098)	(30,906)	370,691	224,122	48,785	272,907	643,598	61,808	705,406	(18,589)	723,995	3,506,635	224,122
2024	284,207	(63,545)	(30,481)	378,233	224,122	49,870	273,992	652,225	63,573	715,798	(20,988)	736,786	3,757,520	224,122
2025	369,084	(58,058)	104,648	322,495	326,974	68,210	395,184	717,679	76,427	794,106	23,905	770,200	3,998,925	326,974
2026	379,239	(59,357)	101,767	336,828	326,974	70,716	397,690	734,518	76,039	810,558	23,363	787,195	4,226,035	326,974
2027	389,948	(59,823)	107,425	342,345	326,974	71,961	398,935	741,280	79,152	820,432	22,434	797,999	4,437,952	326,974
2028	396,556	(60,942)	99,069	358,429	326,974	74,102	401,076	759,505	77,910	837,414	21,513	815,902	4,637,392	326,974
2029	404,734	(62,414)	88,197	378,951	326,974	75,898	402,872	781,822	76,870	858,692	20,512	838,180	4,825,983	326,974
2030	411,598	(62,516)	96,727	377,387	326,974	77,212	404,186	781,573	81,066	862,639	18,855	843,784	5,000,737	326,974
2031	417,344	(63,927)	86,534	394,737	326,974	79,759	406,733	801,470	79,236	880,706	17,233	863,474	5,165,346	326,974
2032	430,981	(64,271)	101,620	393,632	326,974	81,023	407,997	801,629	84,948	886,577	16,147	870,429	5,318,084	326,974
2033	438,704	(65,270)	100,218	403,755	326,974	83,108	410,082	813,837	86,114	899,951	13,050	886,901	5,461,336	326,974
2034	451,590	(66,368)	102,229	415,730	326,974	85,219	412,193	827,922	87,723	915,645	12,324	903,322	5,595,637	326,974
2035	454,028	(67,963)	80,964	441,027	326,974	87,830	414,804	855,831	83,734	939,565	11,379	928,185	5,722,659	326,974
2036	460,496	(69,140)	83,956	445,680	146,766	89,714	236,480	682,160	85,925	768,085	9,992	758,092	5,818,154	146,766
2037	479,815	(69,497)	100,430	448,882	146,766	91,449	238,215	687,097	91,752	778,849	7,633	771,217	5,907,576	146,766
2038	478,652	(71,123)	83,628	466,147	146,766	93,339	240,105	706,252	89,739	795,991	5,840	790,151	5,991,906	146,766
2039	494,009	(71,705)	92,264	473,450	146,766	95,256	242,022	715,472	93,881	809,353	4,158	805,195	6,071,009	146,766
2040	496,113	(73,439)	79,267	490,285	146,766	127,731	274,497	764,782	92,109	856,891	4,537	852,354	6,148,084	146,766
2011 Net Present Value														
Period of 2011-2040	3,332,157	(530,810)	468,825	3,394,142	1,812,173	456,028	2,268,201	5,662,343	476,419	6,136,762	(9,322)	6,148,084		
Base Case O&M 2011-2040							609,444			609,444	0	609,444		
Utility Cost Present Value 2011-2040							2,877,644			6,748,205	(9,322)	6,757,528		

		ICAP
	Surplus MW	Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	31	1,507
2016	(158)	1,973
2017	(142)	1,616
2018	(150)	1,258
2019	(154)	1,306
2020	(158)	1,488
2021	(159)	1,671
2022	(171)	1,853
2023	(177)	2,017
2024	(187)	2,159
2025	202	2,279
2026	189	2,380
2027	176	2,454
2028	165	2,508
2029	155	2,541
2030	143	2,529
2031	129	2,562
2032	120	2,596
2033	95	2,631
2034	89	2,665
2035	81	2,701
2036	70	2,736
2037	53	2,772
2038	40	2,809
2039	28	2,846
2040	30	2,884

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR Low Band Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,310	6,815	0.34
2013	11,885	7,487	6,303	0.28
2014	4,397	7,056	5,741	0.34
2015	7,247	7,614	5,614	0.33
2016	4,097	4,191	1,637	0.01
2017	4,430	4,045	1,814	0.01
2018	4,358	4,263	1,796	0.01
2019	3,557	4,037	1,506	0.01
2020	4,573	4,356	766	0.00
2021	4,372	4,334	763	0.00
2022	4,559	4,365	767	0.00
2023	4,269	4,046	697	0.00
2024	3,655	4,108	711	0.00
2025	4,559	4,876	815	0.00
2026	3,917	4,787	788	0.00
2027	4,558	4,921	820	0.00
2028	3,884	4,782	786	0.00
2029	4,401	4,658	758	0.00
2030	4,332	4,848	803	0.00
2031	3,536	4,677	761	0.00
2032	4,572	4,951	824	0.00
2033	4,374	4,954	823	0.00
2034	4,558	4,982	827	0.00
2035	4,270	4,694	761	0.00
2036	3,658	4,755	775	0.00
2037	4,559	5,012	831	0.00
2038	3,917	4,838	795	0.00
2039	4,558	4,997	830	0.00
2040	3,886	4,839	794	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	91	2,065	1,974	6,900
2013	7,457	138	36	(102)	394	1,455	1,060	6,883
2014	7,469	139	17	(122)	671	1,426	755	6,894
2015	7,479	139	23	(116)	304	1,607	1,304	6,903
2016	7,488	139	19	(120)	587	385	(202)	6,911
2017	7,505	139	28	(111)	732	304	(428)	6,927
2018	7,536	139	37	(102)	582	344	(238)	6,955
2019	7,571	139	36	(103)	816	287	(529)	6,988
2020	7,604	139	34	(106)	569	367	(202)	7,019
2021	7,648	288	34	(254)	554	400	(154)	7,059
2022	7,695	288	34	(254)	507	419	(88)	7,102
2023	7,744	288	34	(254)	768	290	(478)	7,148
2024	7,798	289	34	(255)	754	288	(467)	7,198
2025	7,846	288	34	(254)	358	1,540	1,183	7,242
2026	7,896	288	34	(254)	296	1,464	1,167	7,288
2027	7,947	288	34	(254)	337	1,542	1,205	7,335
2028	7,999	289	34	(255)	339	1,410	1,071	7,383
2029	8,044	288	34	(254)	380	1,290	910	7,425
2030	8,093	288	34	(254)	382	1,384	1,002	7,470
2031	8,143	288	34	(254)	423	1,289	866	7,516
2032	8,195	289	34	(255)	400	1,429	1,030	7,564
2033	8,241	288	34	(254)	370	1,377	1,007	7,606
2034	8,289	288	34	(254)	324	1,358	1,035	7,651
2035	8,339	288	34	(254)	427	1,174	747	7,697
2036	8,389	289	34	(255)	423	1,185	762	7,743
2037	8,439	288	34	(254)	314	1,282	968	7,789
2038	8,488	288	34	(254)	390	1,123	733	7,835
2039	8,538	288	34	(254)	354	1,185	831	7,881
2040	8,589	289	34	(255)	413	1,064	651	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR Low Band Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts				Market					
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	244,613	(20,650)	67,015	178,248	0	0	0	178,248	60,605	238,853	0	238,853	391,780	0
2013	240,839	(29,973)	48,672	222,140	0	0	0	222,140	31,233	253,373	0	253,373	606,454	0
2014	250,619	(37,859)	55,811	232,667	607	0	607	233,274	81,027	314,301	1,379	312,922	850,498	607
2015	232,418	(48,543)	25,350	255,612	607	0	607	256,219	16,156	272,375	(17,667)	290,041	1,058,708	607
2016	240,044	(47,794)	(2,636)	290,474	219,322	33,482	252,804	543,279	1,339	544,618	(3,454)	548,073	1,420,858	219,322
2017	238,596	(46,314)	(15,729)	300,638	219,322	42,424	261,746	562,384	600	562,984	(1,554)	564,537	1,764,222	219,322
2018	249,308	(46,610)	(6,329)	302,247	219,322	43,135	262,457	564,703	159	564,863	(1,679)	566,541	2,081,400	219,322
2019	247,377	(46,382)	(21,274)	315,033	219,322	43,866	263,188	578,221	82	578,303	(2,045)	580,347	2,380,468	219,322
2020	261,277	(47,356)	(5,621)	314,254	226,653	44,765	271,418	585,673	0	585,673	(2,666)	588,338	2,659,542	226,653
2021	267,338	(61,674)	(3,691)	332,704	226,653	45,456	272,109	604,812	0	604,812	(3,030)	607,842	2,924,937	226,653
2022	280,850	(63,589)	(471)	344,910	226,653	46,712	273,365	618,275	66,275	684,550	(4,505)	689,055	3,201,865	226,653
2023	280,694	(63,571)	(24,787)	369,052	226,653	47,688	274,341	643,393	62,286	705,678	(5,584)	711,262	3,464,984	226,653
2024	288,550	(64,086)	(23,977)	376,612	226,653	48,586	275,239	651,852	64,081	715,933	(7,068)	723,001	3,711,175	226,653
2025	372,565	(57,786)	109,940	320,411	329,505	66,657	396,162	716,573	76,829	793,402	38,601	754,801	3,947,754	329,505
2026	383,146	(59,069)	107,541	334,675	329,505	68,963	398,468	733,143	76,490	809,633	38,711	770,923	4,170,169	329,505
2027	393,685	(59,543)	113,032	340,195	329,505	69,999	399,504	739,699	79,579	819,278	38,258	781,019	4,377,577	329,505
2028	400,709	(60,644)	105,094	356,259	329,505	71,950	401,455	757,714	78,380	836,095	37,682	798,413	4,572,742	329,505
2029	409,299	(62,059)	94,635	376,724	329,505	73,584	403,089	779,813	77,382	857,194	36,895	820,299	4,757,310	329,505
2030	415,638	(62,182)	102,633	375,187	329,505	74,603	404,108	779,295	81,520	860,815	35,162	825,653	4,928,309	329,505
2031	421,933	(63,612)	93,095	392,450	329,505	76,952	406,457	798,907	79,751	878,658	33,755	844,903	5,089,378	329,505
2032	435,469	(63,909)	108,121	391,257	329,505	77,950	407,455	798,713	85,451	884,163	32,888	851,275	5,238,755	329,505
2033	443,347	(64,888)	106,922	401,313	329,505	79,741	409,246	810,559	86,635	897,193	30,012	867,182	5,378,822	329,505
2034	457,661	(66,035)	110,723	412,973	329,505	81,805	411,310	824,283	88,404	912,687	29,510	883,178	5,510,128	329,505
2035	458,714	(67,574)	87,746	438,541	329,505	83,977	413,482	852,024	84,261	936,285	28,792	907,492	5,634,318	329,505
2036	465,233	(68,769)	90,889	443,112	329,505	85,760	415,265	858,377	86,455	944,832	27,635	917,197	5,749,855	329,505
2037	483,653	(69,022)	106,184	446,491	329,505	87,281	416,786	863,277	92,187	955,464	25,509	929,955	5,857,682	329,505
2038	483,054	(70,765)	90,238	463,580	329,505	89,120	418,625	882,205	90,231	972,436	23,952	948,484	5,958,911	329,505
2039	498,856	(71,388)	99,467	470,776	329,505	90,962	420,467	891,243	94,422	985,665	22,509	963,156	6,053,531	329,505
2040	500,205	(73,031)	85,503	487,732	329,505	93,224	422,729	910,461	92,570	1,003,031	23,131	979,900	6,142,141	329,505
2011 Net Present Value														
Period of 2011-2040	3,338,295	(534,950)	473,449	3,399,797	1,927,380	410,377	2,337,757	5,737,554	475,790	6,213,344	71,203	6,142,141		
Base Case O&M 2011-2040							609,444			609,444	0	609,444		
Utility Cost Present Value 2011-2040							2,947,201			6,822,787	71,203	6,751,584		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(34)	1,973
2017	(18)	1,616
2018	(26)	1,258
2019	(30)	1,306
2020	(34)	1,488
2021	(35)	1,671
2022	(47)	1,853
2023	(53)	2,017
2024	(63)	2,159
2025	326	2,279
2026	313	2,380
2027	300	2,454
2028	289	2,508
2029	279	2,541
2030	267	2,529
2031	253	2,562
2032	244	2,596
2033	219	2,631
2034	213	2,665
2035	205	2,701
2036	194	2,736
2037	177	2,772
2038	164	2,809
2039	152	2,846
2040	154	2,884

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR Low Band Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,310	6,815	0.34
2013	11,885	7,487	6,303	0.28
2014	4,397	7,056	5,741	0.34
2015	7,161	6,772	3,153	0.28
2016	4,097	4,223	1,640	0.01
2017	4,430	4,076	1,817	0.01
2018	4,358	4,294	1,799	0.01
2019	3,557	4,068	1,510	0.01
2020	4,573	4,388	770	0.00
2021	4,372	4,365	766	0.00
2022	4,559	4,395	770	0.00
2023	4,269	4,077	701	0.00
2024	3,655	4,141	715	0.00
2025	4,559	4,901	818	0.00
2026	3,917	4,816	791	0.00
2027	4,558	4,948	823	0.00
2028	3,884	4,811	789	0.00
2029	4,401	4,690	762	0.00
2030	4,332	4,875	806	0.00
2031	3,536	4,708	764	0.00
2032	4,572	4,980	827	0.00
2033	4,374	4,984	827	0.00
2034	4,558	5,020	831	0.00
2035	4,270	4,723	765	0.00
2036	3,658	4,784	778	0.00
2037	4,559	5,035	834	0.00
2038	3,917	4,865	798	0.00
2039	4,558	5,026	833	0.00
2040	3,886	4,863	797	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	91	2,065	1,974	6,900
2013	7,457	138	36	(102)	394	1,455	1,060	6,883
2014	7,469	139	17	(122)	671	1,426	755	6,894
2015	7,479	139	23	(116)	486	862	376	6,903
2016	7,488	139	19	(120)	544	430	(114)	6,911
2017	7,505	139	28	(111)	682	337	(345)	6,927
2018	7,536	139	37	(102)	538	383	(155)	6,955
2019	7,571	139	36	(103)	763	321	(442)	6,988
2020	7,604	139	34	(106)	526	410	(116)	7,019
2021	7,648	288	34	(254)	514	443	(72)	7,059
2022	7,695	288	34	(254)	470	458	(12)	7,102
2023	7,744	288	34	(254)	716	321	(395)	7,148
2024	7,798	289	34	(255)	697	319	(378)	7,198
2025	7,846	288	34	(254)	354	1,604	1,250	7,242
2026	7,896	288	34	(254)	289	1,532	1,242	7,288
2027	7,947	288	34	(254)	334	1,609	1,275	7,335
2028	7,999	289	34	(255)	329	1,476	1,147	7,383
2029	8,044	288	34	(254)	364	1,356	992	7,425
2030	8,093	288	34	(254)	376	1,449	1,073	7,470
2031	8,143	288	34	(254)	407	1,353	946	7,516
2032	8,195	289	34	(255)	388	1,495	1,107	7,564
2033	8,241	288	34	(254)	359	1,445	1,086	7,606
2034	8,289	288	34	(254)	313	1,451	1,139	7,651
2035	8,339	288	34	(254)	415	1,239	824	7,697
2036	8,389	289	34	(255)	415	1,253	839	7,743
2037	8,439	288	34	(254)	318	1,345	1,027	7,789
2038	8,488	288	34	(254)	386	1,187	801	7,835
2039	8,538	288	34	(254)	347	1,252	906	7,881
2040	8,589	289	34	(255)	409	1,121	712	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR Low Band Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts				Market Value of					
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)
2011	192,631	(12,768)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	244,613	(20,650)	87,015	178,248	0	0	0	178,248	60,605	238,853	0	238,853	391,780	0
2013	240,839	(29,973)	48,672	222,140	0	0	0	222,140	31,233	253,373	0	253,373	606,454	0
2014	250,619	(37,859)	55,811	232,667	607	0	607	233,274	81,027	314,301	1,379	312,922	850,498	607
2015	232,418	(48,543)	25,350	255,612	607	0	607	256,219	16,155	272,375	(17,667)	290,041	1,058,708	607
2016	67,394	(40,348)	(242,058)	349,799	36,583	0	36,583	386,382	1,244	387,627	(96,221)	483,847	1,378,420	36,583
2017	63,956	(38,296)	(257,784)	360,036	36,583	0	36,583	396,619	547	397,166	(77,515)	474,681	1,667,131	36,583
2018	70,517	(37,888)	(251,981)	360,386	36,583	0	36,583	396,969	144	397,112	(60,830)	457,942	1,923,510	36,583
2019	65,047	(37,698)	(270,602)	373,347	36,583	0	36,583	409,930	73	410,003	(63,458)	473,462	2,167,497	36,583
2020	261,277	(47,356)	(5,621)	314,254	238,249	44,765	283,014	597,269	0	597,269	(2,666)	599,934	2,452,072	238,249
2021	267,338	(61,674)	(3,691)	332,704	238,249	45,456	283,705	616,408	0	616,408	(3,030)	619,438	2,722,530	238,249
2022	280,850	(63,589)	(471)	344,910	238,249	46,712	284,961	629,871	66,275	696,146	(4,505)	700,651	3,004,118	238,249
2023	280,694	(63,571)	(24,787)	369,052	238,249	47,688	285,937	654,989	62,286	717,274	(5,584)	722,858	3,271,527	238,249
2024	288,550	(64,086)	(23,977)	376,613	238,249	48,586	286,835	663,448	64,081	727,529	(7,068)	734,597	3,521,667	238,249
2025	372,565	(57,786)	109,940	320,411	341,101	66,657	407,758	728,169	76,829	804,998	38,601	766,397	3,761,880	341,101
2026	383,146	(59,069)	107,541	334,675	341,101	68,963	410,064	744,739	76,490	821,229	38,711	782,519	3,987,641	341,101
2027	393,685	(59,543)	113,032	340,195	341,101	69,999	411,100	751,295	79,579	830,874	38,258	792,615	4,198,128	341,101
2028	400,709	(60,644)	105,094	356,259	341,101	71,950	413,051	769,310	78,380	847,691	37,682	810,009	4,396,128	341,101
2029	409,299	(62,059)	94,635	376,724	341,101	73,584	414,685	791,409	77,382	868,790	36,895	831,895	4,583,305	341,101
2030	415,638	(62,182)	102,633	375,187	341,101	74,603	415,704	790,891	81,520	872,411	35,162	837,249	4,756,705	341,101
2031	421,933	(63,612)	93,095	392,450	341,101	76,952	418,053	810,503	79,751	890,254	33,755	856,499	4,919,984	341,101
2032	435,469	(63,909)	108,121	391,257	341,101	77,950	419,051	810,309	85,451	895,759	32,888	862,871	5,071,397	341,101
2033	443,347	(64,888)	106,922	401,313	341,101	79,741	420,842	822,155	86,635	908,789	30,012	878,778	5,213,336	341,101
2034	457,661	(66,035)	110,723	412,973	341,101	81,805	422,906	835,879	88,404	924,283	29,510	894,774	5,346,366	341,101
2035	458,714	(67,574)	87,746	438,541	341,101	83,977	425,078	863,620	84,261	947,881	28,792	919,088	5,472,144	341,101
2036	465,233	(68,769)	90,869	443,112	341,101	85,760	426,861	869,973	86,455	956,428	27,635	928,793	5,589,141	341,101
2037	483,653	(69,022)	106,184	446,491	341,101	87,281	428,382	874,873	92,187	967,060	25,509	941,551	5,698,313	341,101
2038	483,054	(70,765)	90,238	463,580	341,101	89,120	430,221	893,801	90,231	984,032	23,952	960,080	5,800,780	341,101
2039	498,856	(71,368)	99,467	470,776	341,101	90,962	432,063	902,839	94,422	997,261	22,509	974,752	5,896,539	341,101
2040	500,204	(73,031)	85,503	487,732	341,101	93,224	434,325	922,057	92,570	1,014,627	23,131	991,496	5,986,197	341,101
2011 Net Present Value														
Period of 2011-2040	2,923,937	(515,796)	(97,990)	3,537,723	1,556,036	315,696	1,871,732	5,409,455	475,682	5,885,137	(101,059)	5,986,197		
Base Case O&M 2011-2040							609,444			609,444	0	609,444		
Utility Cost Present Value 2011-2040							2,481,175			6,494,581	(101,059)	6,595,640		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(922)	1,616
2018	(930)	1,258
2019	(934)	1,306
2020	(34)	1,488
2021	(35)	1,671
2022	(47)	1,853
2023	(53)	2,017
2024	(63)	2,159
2025	326	2,279
2026	313	2,380
2027	300	2,454
2028	289	2,508
2029	279	2,541
2030	267	2,529
2031	253	2,562
2032	244	2,596
2033	219	2,631
2034	213	2,665
2035	205	2,701
2036	194	2,736
2037	177	2,772
2038	164	2,809
2039	152	2,846
2040	154	2,884

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR Low Band Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,310	6,815	0.34
2013	11,885	7,487	6,303	0.28
2014	4,397	7,056	5,741	0.34
2015	7,161	6,772	3,153	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	4,388	770	0.00
2021	4,372	4,365	766	0.00
2022	4,559	4,395	770	0.00
2023	4,269	4,077	701	0.00
2024	3,655	4,141	715	0.00
2025	4,559	4,901	818	0.00
2026	3,917	4,816	791	0.00
2027	4,558	4,948	823	0.00
2028	3,884	4,811	769	0.00
2029	4,401	4,690	762	0.00
2030	4,332	4,875	806	0.00
2031	3,536	4,708	764	0.00
2032	4,572	4,980	827	0.00
2033	4,374	4,984	827	0.00
2034	4,558	5,020	831	0.00
2035	4,270	4,723	765	0.00
2036	3,658	4,784	778	0.00
2037	4,559	5,035	834	0.00
2038	3,917	4,865	798	0.00
2039	4,558	5,026	833	0.00
2040	3,886	4,863	797	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	91	2,065	1,974	6,900
2013	7,457	138	36	(102)	394	1,455	1,060	6,883
2014	7,469	139	17	(122)	671	1,426	755	6,894
2015	7,479	139	23	(116)	486	862	376	6,903
2016	7,488	139	19	(120)	4,618		(4,618)	6,911
2017	7,505	139	28	(111)	4,780		(4,780)	6,927
2018	7,536	139	37	(102)	4,579		(4,579)	6,955
2019	7,571	139	36	(103)	4,866		(4,866)	6,988
2020	7,604	139	34	(106)	526	410	(116)	7,019
2021	7,648	288	34	(254)	514	443	(72)	7,059
2022	7,695	288	34	(254)	470	458	(12)	7,102
2023	7,744	288	34	(254)	716	321	(395)	7,148
2024	7,798	289	34	(255)	697	319	(378)	7,198
2025	7,846	288	34	(254)	354	1,604	1,250	7,242
2026	7,896	288	34	(254)	289	1,532	1,242	7,288
2027	7,947	288	34	(254)	334	1,609	1,275	7,335
2028	7,999	289	34	(255)	329	1,476	1,147	7,383
2029	8,044	288	34	(254)	364	1,356	992	7,425
2030	8,093	288	34	(254)	376	1,449	1,073	7,470
2031	8,143	288	34	(254)	407	1,353	946	7,516
2032	8,195	289	34	(255)	388	1,495	1,107	7,564
2033	8,241	288	34	(254)	359	1,445	1,086	7,606
2034	8,289	288	34	(254)	313	1,451	1,139	7,651
2035	8,339	288	34	(254)	415	1,239	824	7,697
2036	8,389	289	34	(255)	415	1,253	839	7,743
2037	8,439	288	34	(254)	318	1,345	1,027	7,789
2038	8,488	288	34	(254)	366	1,187	801	7,835
2039	8,538	288	34	(254)	347	1,252	906	7,881
2040	8,589	289	34	(255)	409	1,121	712	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	1,288	1 -904 MW NGCC,	0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FT_CSAPR Low Band Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	192,631	(12,788)	40,914	164,505	0	(0)	(0)	164,505	7,418	171,923	0	171,923	171,923	0
2012	244,613	(20,650)	87,015	178,248	0	0	0	178,248	60,605	238,853	0	238,853	391,780	0
2013	240,839	(29,973)	48,672	222,140	0	0	0	222,140	31,233	253,373	0	253,373	606,454	0
2014	250,619	(37,859)	55,811	232,667	607	0	607	233,274	81,027	314,301	1,379	312,922	850,498	607
2015	232,418	(48,543)	25,350	255,612	607	0	607	256,219	16,156	272,375	(17,667)	290,041	1,058,708	607
2016	67,394	(40,348)	(242,058)	349,799	36,583	0	36,583	386,382	1,244	387,627	(96,221)	483,847	1,378,420	36,583
2017	63,956	(38,295)	(257,784)	360,036	36,583	0	36,583	396,619	547	397,166	(77,515)	474,681	1,667,131	36,583
2018	70,517	(37,886)	(251,981)	360,386	36,583	0	36,583	396,969	144	397,112	(60,830)	457,942	1,923,510	36,583
2019	65,047	(37,698)	(270,602)	373,347	36,583	0	36,583	409,930	73	410,003	(63,458)	473,462	2,167,497	36,583
2020	76,375	(38,471)	(256,537)	371,383	43,914	0	43,914	415,297	0	415,297	(72,612)	487,909	2,398,933	43,914
2021	77,487	(52,457)	(258,957)	388,902	43,914	0	43,914	432,816	0	432,816	(81,574)	514,390	2,623,525	43,914
2022	78,768	(54,372)	(307,606)	440,746	43,914	0	43,914	484,660	41,846	526,507	(91,609)	618,116	2,871,943	43,914
2023	72,077	(53,969)	(339,961)	466,007	43,914	0	43,914	509,921	37,415	547,337	(100,398)	647,735	3,111,561	43,914
2024	73,165	(56,210)	(341,255)	470,630	43,914	0	43,914	514,544	38,892	553,436	(108,547)	661,984	3,336,975	43,914
2025	372,565	(57,786)	109,940	320,411	356,636	66,657	423,293	743,704	76,829	820,533	38,601	781,932	3,582,058	356,636
2026	383,146	(59,069)	107,541	334,675	356,636	68,963	425,599	760,274	76,490	836,764	38,711	798,054	3,812,300	356,636
2027	393,685	(59,543)	113,032	340,195	356,636	69,999	426,635	766,830	79,579	846,409	38,258	808,150	4,026,913	356,636
2028	400,709	(60,644)	105,094	356,259	356,636	71,950	428,586	784,845	78,380	863,226	37,682	825,544	4,228,710	356,636
2029	409,299	(62,059)	94,635	376,724	356,636	73,584	430,220	806,944	77,382	884,325	36,895	847,430	4,419,383	356,636
2030	415,638	(62,182)	102,633	375,187	356,636	74,603	431,239	806,426	81,520	887,946	35,162	852,784	4,596,000	356,636
2031	421,933	(63,612)	93,095	392,450	356,636	76,952	433,588	826,038	79,751	905,789	33,755	872,034	4,762,241	356,636
2032	435,469	(63,909)	108,121	391,257	356,636	77,950	434,586	825,844	85,451	911,294	32,888	878,406	4,916,380	356,636
2033	443,347	(64,888)	106,922	401,313	355,636	79,741	436,377	837,690	86,635	924,324	30,012	894,313	5,060,829	356,636
2034	457,661	(66,035)	110,723	412,973	356,636	81,805	438,441	851,414	88,404	939,818	29,510	910,309	5,196,168	356,636
2035	458,714	(67,574)	87,746	438,541	356,636	83,977	440,613	879,155	84,261	963,416	28,792	934,623	5,324,072	356,636
2036	465,233	(68,769)	90,889	443,112	356,636	85,760	442,396	885,508	86,455	971,963	27,635	944,328	5,443,025	356,636
2037	483,653	(69,022)	106,184	446,491	356,636	87,281	443,917	890,408	92,187	982,595	25,509	957,086	5,553,998	356,636
2038	483,054	(70,765)	90,238	463,580	356,636	89,120	445,756	909,336	90,232	999,567	23,952	975,615	5,658,124	356,636
2039	498,856	(71,388)	99,467	470,776	356,636	90,962	447,598	918,374	94,422	1,012,796	22,509	990,287	5,755,409	356,636
2040	500,204	(73,031)	85,503	487,732	356,636	93,224	449,860	937,592	92,570	1,030,162	23,131	1,007,031	5,846,472	356,636
2011 Net Present Value														
Period of 2011-2040	2,521,607	(497,619)	(676,530)	3,695,756	1,207,804	221,656	1,429,460	5,125,216	448,087	5,573,303	(273,169)	5,846,472		
Base Case O&M 2011-2040							609,444			609,444	0	609,444		
Utility Cost Present Value 2011-2040							2,038,903			6,182,746	(273,169)	6,455,915		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(922)	1,616
2018	(930)	1,258
2019	(934)	1,306
2020	(938)	1,488
2021	(939)	1,671
2022	(951)	1,853
2023	(957)	2,017
2024	(967)	2,159
2025	326	2,279
2026	313	2,380
2027	300	2,454
2028	289	2,508
2029	279	2,541
2030	267	2,529
2031	253	2,562
2032	244	2,596
2033	219	2,631
2034	213	2,665
2035	205	2,701
2036	194	2,736
2037	177	2,772
2038	164	2,809
2039	152	2,846
2040	154	2,884

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FT_CSAPR Low Band Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,310	6,815	0.34
2013	11,885	7,467	6,303	0.28
2014	4,397	7,056	5,741	0.34
2015	7,161	6,772	3,153	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	2,783	597	0.00
2021	4,372	2,775	595	0.00
2022	4,559	2,775	595	0.00
2023	4,269	2,449	525	0.00
2024	3,655	2,513	539	0.00
2025	4,559	4,901	818	0.00
2026	3,917	4,816	791	0.00
2027	4,558	4,948	823	0.00
2028	3,884	4,811	789	0.00
2029	4,401	4,690	762	0.00
2030	4,332	4,875	806	0.00
2031	3,536	4,708	764	0.00
2032	4,572	4,980	827	0.00
2033	4,374	4,984	827	0.00
2034	4,558	5,020	831	0.00
2035	4,270	4,723	765	0.00
2036	3,658	4,784	778	0.00
2037	4,559	5,035	834	0.00
2038	3,917	4,865	798	0.00
2039	4,558	5,026	833	0.00
2040	3,886	4,863	797	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	91	2,065	1,974	6,900
2013	7,457	138	36	(102)	394	1,455	1,060	6,883
2014	7,469	139	17	(122)	671	1,426	755	6,894
2015	7,479	139	23	(116)	486	862	376	6,903
2016	7,488	139	19	(120)	4,618		(4,618)	6,911
2017	7,505	139	28	(111)	4,780		(4,780)	6,927
2018	7,536	139	37	(102)	4,579		(4,579)	6,955
2019	7,571	139	36	(103)	4,866		(4,866)	6,988
2020	7,604	139	34	(106)	4,560		(4,560)	7,019
2021	7,648	288	34	(254)	4,469		(4,469)	7,059
2022	7,695	288	34	(254)	4,484		(4,484)	7,102
2023	7,744	288	34	(254)	4,896		(4,896)	7,148
2024	7,798	289	34	(255)	4,863		(4,863)	7,198
2025	7,846	288	34	(254)	354	1,604	1,250	7,242
2026	7,896	288	34	(254)	289	1,532	1,242	7,288
2027	7,947	288	34	(254)	334	1,609	1,275	7,335
2028	7,999	289	34	(255)	329	1,476	1,147	7,383
2029	8,044	288	34	(254)	364	1,356	992	7,425
2030	8,093	288	34	(254)	376	1,449	1,073	7,470
2031	8,143	288	34	(254)	407	1,353	946	7,516
2032	8,195	289	34	(255)	388	1,495	1,107	7,564
2033	8,241	288	34	(254)	359	1,445	1,086	7,605
2034	8,289	288	34	(254)	313	1,451	1,139	7,651
2035	8,339	288	34	(254)	415	1,239	824	7,697
2036	8,389	289	34	(255)	415	1,253	839	7,743
2037	8,439	288	34	(254)	318	1,345	1,027	7,789
2038	8,488	288	34	(254)	386	1,187	801	7,835
2039	8,538	288	34	(254)	347	1,252	906	7,881
2040	8,589	289	34	(255)	409	1,121	712	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,303	1- 407 MW CC,1 -904 MW NGCC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

Big Sandy Unit 2 under: "Fleet Transition-No Carbon" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013					
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	225 MW- ICAP	225 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				1 -904 MW NGCC	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1- 407 MW CC
2026					
~					
2040					
Life-Cycle Analysis Period (2011-2040) ($000)					
CPW of Revenue Requirements	6,296,457	6,809,054	6,734,818	6,473,342	6,146,215
Less: ICAP Revenue	(115,572)	82,264	(11,440)	(104,198)	(312,943)
CPW of Revenue Requirements, Net	6,412,030	6,726,790	6,746,259	6,577,540	6,459,157
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		512,597	438,361	176,885	(150,242)
Less: ICAP / Pool Revenue		197,837	104,132	11,375	(197,370)
CPW of Revenue Requirements, Net		314,760	334,229	165,510	47,128
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year) RETROFIT Cost Recovery		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		351,960	371,429	202,710	84,328

Note:
o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...
Inclusive of:
1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Big Sandy 2 UD Analysis Under FTCA_CSAPR No Carbon Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life	***BS1 Repower 20 yr book life***	***NGCC Replacement***	***Market to 2020***	***Market to 2025***
2011				0 MW- ICAP	0 MW- ICAP
2012				0 MW- ICAP	0 MW- ICAP
2013				0 MW- ICAP	0 MW- ICAP
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire		Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	**Big Sandy 2 Retrofit**	**Big Sandy 1 Retire**	**1 -904 MW NGCC**	938 MW- ICAP	938 MW- ICAP
		1 -780 MW Repower,			
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				**1 -904 MW NGCC**	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
					1 -904 MW NGCC,
2025	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1-407 MW CC**
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
FTCA_CSAPR					
No Carbon					
CPW	6,296,457	6,734,818	6,809,054	6,473,342	6,146,215
ICAP Revenue	(115,572)	(11,440)	82,264	(104,198)	(312,943)
Total	$6,412,030	$6,746,259	$6,726,790	$6,577,540	$6,459,157
Cost Over Retrofit		$334,229	$314,760	$165,510	$47,128

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR No Carbon Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,693	(21,043)	94,720	177,017	0	0	0	177,017	87,010	264,027	0	264,027	420,444	0
2013	228,706	(29,787)	37,029	221,464	0	0	0	221,464	51,796	273,260	0	273,260	651,968	0
2014	275,667	(38,373)	57,276	256,764	607	0	607	257,371	102,292	359,662	1,379	358,283	931,388	607
2015	276,036	(51,199)	45,765	281,470	607	0	607	282,077	29,834	311,911	(17,667)	329,577	1,167,978	607
2016	165,109	(48,057)	(85,845)	299,010	147,762	76,534	224,296	523,306	2,303	525,609	(96,221)	621,830	1,578,866	147,762
2017	236,602	(54,001)	29,446	261,157	147,762	137,486	285,248	546,405	1,512	547,918	(15,599)	563,517	1,921,608	147,762
2018	254,756	(55,002)	52,469	257,288	147,762	149,165	296,927	554,215	626	554,842	(14,125)	568,967	2,240,144	147,762
2019	242,046	(57,241)	22,600	276,687	147,762	139,456	287,218	563,906	243	564,149	(16,560)	580,709	2,539,399	147,762
2020	257,562	(59,022)	50,706	265,878	155,093	140,118	295,211	561,088	0	561,088	(19,569)	580,658	2,814,829	155,093
2021	262,406	(72,824)	55,551	279,679	155,093	143,557	298,650	578,329	0	578,329	(22,127)	600,456	3,077,000	155,093
2022	258,149	(72,699)	41,010	289,838	155,093	144,328	299,421	589,259	0	589,259	(25,556)	614,815	3,324,091	155,093
2023	230,750	(72,048)	(19,680)	322,477	155,093	140,764	295,857	618,334	0	618,334	(28,239)	646,574	3,563,280	155,093
2024	261,784	(76,324)	21,655	316,453	155,093	150,793	305,886	622,339	0	622,339	(31,070)	653,408	3,785,774	155,093
2025	339,083	(60,420)	123,632	275,871	257,945	167,564	425,509	701,380	0	701,380	21,410	679,969	3,998,898	257,945
2026	357,249	(61,510)	140,207	278,552	257,945	177,015	434,960	713,511	0	713,511	20,338	693,174	4,198,882	257,945
2027	354,243	(62,356)	122,463	294,136	257,945	175,505	433,450	727,586	0	727,586	18,985	708,601	4,387,059	257,945
2028	373,519	(63,321)	140,371	296,470	257,945	185,387	443,332	739,801	0	739,801	17,718	722,083	4,563,565	257,945
2029	374,715	(64,548)	128,426	310,837	257,945	188,980	446,925	757,762	0	757,762	16,406	741,357	4,730,371	257,945
2030	367,505	(64,043)	101,942	329,606	257,945	184,982	442,927	772,533	0	772,533	14,645	757,888	4,887,335	257,945
2031	388,279	(66,478)	124,052	330,706	146,766	148,982	295,748	626,454	0	626,454	12,544	613,911	5,004,369	146,766
2032	406,134	(66,775)	143,952	328,958	146,766	150,055	296,821	625,779	0	625,779	11,092	614,687	5,112,231	146,766
2033	413,397	(67,754)	141,024	340,127	146,766	149,654	296,420	636,547	0	636,547	7,407	629,139	5,213,849	146,766
2034	398,132	(68,230)	97,762	368,601	146,766	144,709	291,475	660,076	0	660,076	6,431	653,645	5,311,029	146,766
2035	417,871	(71,173)	114,467	374,577	146,766	156,847	303,613	678,191	0	678,191	5,232	672,959	5,403,124	146,766
2036	427,126	(72,106)	116,708	382,524	146,766	159,432	306,198	688,722	0	688,722	3,574	685,148	5,489,430	146,766
2037	443,642	(72,498)	132,019	384,120	146,766	161,708	308,474	692,594	0	692,594	899	691,695	5,569,631	146,766
2038	444,332	(74,688)	116,950	402,070	146,766	164,083	310,849	712,919	0	712,919	(1,119)	714,037	5,645,839	146,766
2039	459,643	(75,039)	127,793	406,888	146,766	167,399	314,165	721,053	0	721,053	(2,979)	724,032	5,716,967	146,766
2040	462,898	(76,583)	113,762	425,719	146,766	347,616	494,382	920,102	0	920,102	(2,649)	922,751	5,800,409	146,766
2011 Net Present Value														
Period of 2011-2040	3,194,420	(582,102)	667,347	3,109,175	1,257,570	1,082,589	2,340,159	5,449,334	235,502	5,684,836	(115,572)	5,800,409		
Base Case O&M 2011-2040							611,621			611,621	0	611,621		
Utility Cost Present Value 2011-2040							2,951,780			6,296,457	(115,572)	6,412,030		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(178)	1,687
2018	(189)	1,438
2019	(197)	1,614
2020	(206)	1,830
2021	(206)	2,065
2022	(218)	2,255
2023	(224)	2,420
2024	(234)	2,552
2025	155	2,664
2026	142	2,762
2027	129	2,839
2028	118	2,892
2029	108	2,919
2030	96	2,927
2031	82	2,936
2032	72	2,944
2033	48	2,953
2034	42	2,962
2035	34	2,970
2036	23	2,979
2037	6	2,988
2038	(7)	2,996
2039	(19)	3,005
2040	(17)	3,014

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR No Carbon Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,381	6,969	0.34
2013	7,356	6,809	5,832	0.29
2014	5,011	6,985	5,268	0.33
2015	9,351	7,377	3,886	0.28
2016	4,097	5,146	2,090	0.15
2017	4,430	7,006	2,756	0.27
2018	4,358	7,431	2,788	0.28
2019	3,557	6,936	2,433	0.26
2020	4,573	7,452	1,742	0.27
2021	4,372	7,435	1,738	0.27
2022	4,559	7,225	1,686	0.25
2023	4,269	6,335	1,478	0.22
2024	3,655	6,961	1,630	0.25
2025	4,559	7,482	1,671	0.24
2026	3,917	7,753	1,746	0.27
2027	4,558	7,496	1,673	0.24
2028	3,884	7,763	1,749	0.27
2029	4,401	7,609	1,717	0.27
2030	4,332	7,245	1,612	0.23
2031	3,536	7,594	1,714	0.27
2032	4,572	7,913	1,784	0.27
2033	4,374	7,894	1,779	0.27
2034	4,558	7,307	1,627	0.23
2035	4,270	7,564	1,709	0.27
2036	3,658	7,629	1,724	0.27
2037	4,559	7,868	1,774	0.26
2038	3,917	7,695	1,739	0.26
2039	4,558	7,863	1,775	0.27
2040	3,886	7,702	1,740	0.27

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	77	2,142	2,065	6,900
2013	7,457	138	36	(102)	800	1,203	403	6,883
2014	7,469	139	17	(122)	698	1,346	648	6,894
2015	7,479	139	23	(116)	255	1,252	997	6,903
2016	7,488	139	19	(120)	2,370	746	(1,624)	6,911
2017	7,505	139	28	(111)	305	863	557	6,927
2018	7,536	139	37	(102)	151	1,150	1,000	6,955
2019	7,571	139	36	(103)	341	767	427	6,988
2020	7,604	139	34	(106)	170	1,138	968	7,019
2021	7,648	288	34	(254)	158	1,204	1,046	7,059
2022	7,695	288	34	(254)	334	1,081	747	7,102
2023	7,744	288	34	(254)	781	471	(311)	7,148
2024	7,798	289	34	(255)	341	727	386	7,198
2025	7,846	288	34	(254)	164	1,839	1,675	7,242
2026	7,896	288	34	(254)	108	2,021	1,913	7,288
2027	7,947	288	34	(254)	277	1,890	1,613	7,335
2028	7,999	289	34	(255)	129	1,958	1,829	7,383
2029	8,044	288	34	(254)	145	1,747	1,602	7,425
2030	8,093	288	34	(254)	498	1,702	1,204	7,470
2031	8,143	288	34	(254)	164	1,642	1,478	7,516
2032	8,195	289	34	(255)	97	1,842	1,745	7,564
2033	8,241	288	34	(254)	137	1,818	1,681	7,606
2034	8,289	288	34	(254)	432	1,485	1,053	7,651
2035	8,339	288	34	(254)	194	1,427	1,234	7,697
2036	8,389	289	34	(255)	201	1,439	1,237	7,743
2037	8,439	288	34	(254)	170	1,606	1,436	7,789
2038	8,488	288	34	(254)	181	1,377	1,196	7,835
2039	8,538	288	34	(254)	164	1,481	1,317	7,881
2040	8,589	289	34	(255)	247	1,357	1,110	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	Retrofit	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	1,131		407	1,538	13.4%
2033	1,372	1,123		407	1,530	11.6%
2034	1,378	1,123		407	1,530	11.1%
2035	1,389	1,127		407	1,534	10.5%
2036	1,399	1,127		407	1,534	9.7%
2037	1,415	1,127		407	1,534	8.4%
2038	1,427	1,127		407	1,534	7.5%
2039	1,438	1,127		407	1,534	6.7%
2040	1,436	1,127		407	1,534	6.9%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR No Carbon Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,693	(21,043)	94,720	177,017	0	0	0	177,017	87,010	264,027	0	264,027	420,444	0
2013	228,697	(29,787)	37,019	221,464	0	(1)	(1)	221,464	51,794	273,257	0	273,257	651,966	0
2014	275,667	(38,373)	57,276	256,764	607	0	607	257,371	102,292	359,662	1,379	358,283	931,386	607
2015	307,154	(45,543)	94,808	257,889	607	45,536	46,143	304,033	35,239	339,272	2,451	336,821	1,173,177	607
2016	262,604	(47,912)	(9,567)	320,083	216,791	33,311	250,102	570,185	1,728	571,913	(16,179)	588,092	1,561,771	216,791
2017	261,699	(46,199)	(23,744)	331,642	216,791	42,299	259,090	590,732	982	591,713	(12,499)	604,212	1,929,266	216,791
2018	273,498	(46,513)	(14,664)	334,676	216,791	43,112	259,903	594,578	397	594,975	(11,189)	606,164	2,268,627	216,791
2019	271,980	(45,733)	(30,647)	348,360	216,791	44,142	260,933	609,293	152	609,446	(12,933)	622,378	2,589,355	216,791
2020	278,165	(47,004)	(14,648)	339,817	224,122	45,158	269,280	609,096	0	609,096	(15,081)	624,177	2,885,428	224,122
2021	281,892	(61,689)	(10,074)	353,655	224,122	46,159	270,281	623,936	0	623,936	(17,063)	640,999	3,165,300	224,122
2022	284,894	(61,722)	(12,864)	359,480	224,122	47,241	271,363	630,843	0	630,843	(20,025)	650,868	3,426,881	224,122
2023	283,071	(61,982)	(35,691)	380,745	224,122	48,367	272,489	653,234	0	653,234	(22,305)	675,538	3,676,785	224,122
2024	294,239	(62,169)	(34,752)	391,161	224,122	49,523	273,645	664,806	0	664,806	(24,811)	689,617	3,911,608	224,122
2025	373,508	(57,942)	84,185	347,265	326,974	67,077	394,051	741,315	0	741,315	27,944	713,372	4,135,202	326,974
2026	388,410	(59,048)	83,689	363,769	326,974	69,789	396,763	760,532	0	760,532	27,111	733,420	4,346,797	326,974
2027	397,041	(59,622)	88,034	368,629	326,974	70,959	397,933	766,562	0	766,562	25,946	740,616	4,543,476	326,974
2028	406,541	(60,711)	80,606	386,647	326,974	73,132	400,106	786,753	0	786,753	24,810	761,943	4,729,726	326,974
2029	414,318	(62,075)	72,362	404,032	326,974	75,076	402,050	806,081	0	806,081	23,563	782,518	4,905,793	326,974
2030	420,999	(62,322)	79,215	404,106	326,974	76,282	403,256	807,362	0	807,362	21,823	785,539	5,068,484	326,974
2031	428,868	(63,747)	68,647	423,969	326,974	78,785	405,759	829,728	0	829,728	19,743	809,985	5,222,896	326,974
2032	439,714	(64,139)	83,156	420,697	326,974	80,071	407,045	827,743	0	827,743	18,312	809,431	5,364,931	326,974
2033	448,200	(65,162)	80,767	432,595	326,974	81,928	408,902	841,497	0	841,497	14,649	826,848	5,498,483	326,974
2034	461,328	(66,253)	83,684	443,897	326,974	84,243	411,217	855,114	0	855,114	13,693	841,421	5,623,581	326,974
2035	463,949	(67,980)	63,525	468,404	326,974	86,866	413,840	882,244	0	882,244	12,516	869,728	5,742,603	326,974
2036	475,050	(69,174)	67,715	476,510	146,766	88,712	235,478	711,987	0	711,987	10,879	701,108	5,830,920	146,766
2037	488,331	(69,360)	79,626	478,064	146,766	90,241	237,007	715,071	0	715,071	8,225	706,846	5,912,878	146,766
2038	490,915	(71,055)	65,460	496,511	146,766	92,333	239,099	735,609	0	735,609	6,229	729,380	5,990,723	146,766
2039	504,540	(71,687)	74,696	501,531	146,766	94,326	241,092	742,623	0	742,623	4,390	738,232	6,063,246	146,766
2040	510,643	(73,445)	63,533	520,555	146,766	126,916	273,682	794,237	0	794,237	4,742	789,495	6,134,638	146,766
2011 Net Present Value														
Period of 2011-2040	3,500,870	(531,369)	411,864	3,620,375	1,812,173	452,146	2,264,319	5,884,694	238,503	6,123,198	(11,440)	6,134,638		
Base Case O&M 2011-2040							611,621			611,621	0	611,621		
Utility Cost Present Value 2011-2040							2,875,940			6,734,818	(11,440)	6,746,259		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	31	1,507
2016	(158)	1,973
2017	(142)	1,687
2018	(150)	1,438
2019	(154)	1,614
2020	(158)	1,830
2021	(159)	2,065
2022	(171)	2,255
2023	(177)	2,420
2024	(187)	2,552
2025	202	2,664
2026	189	2,762
2027	176	2,839
2028	165	2,892
2029	155	2,919
2030	143	2,927
2031	129	2,936
2032	120	2,944
2033	95	2,953
2034	89	2,962
2035	81	2,970
2036	70	2,979
2037	53	2,988
2038	40	2,996
2039	28	3,005
2040	30	3,014

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR No Carbon Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,381	6,969	0.34
2013	7,356	6,808	5,632	0.29
2014	5,011	6,985	5,268	0.33
2015	9,351	8,124	6,063	0.32
2016	4,097	4,181	1,636	0.01
2017	4,430	4,033	1,812	0.01
2018	4,358	4,249	1,794	0.01
2019	3,557	4,027	1,505	0.01
2020	4,573	4,341	764	0.00
2021	4,372	4,330	762	0.00
2022	4,559	4,332	763	0.00
2023	4,269	4,011	693	0.00
2024	3,655	4,080	708	0.00
2025	4,559	4,785	805	0.00
2026	3,917	4,716	780	0.00
2027	4,558	4,846	812	0.00
2028	3,884	4,711	778	0.00
2029	4,401	4,600	752	0.00
2030	4,332	4,784	796	0.00
2031	3,536	4,612	753	0.00
2032	4,572	4,887	817	0.00
2033	4,374	4,888	817	0.00
2034	4,558	4,922	821	0.00
2035	4,270	4,636	755	0.00
2036	3,658	4,709	770	0.00
2037	4,559	4,946	824	0.00
2038	3,917	4,783	789	0.00
2039	4,558	4,947	824	0.00
2040	3,886	4,797	789	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Requirement 0.923 GWh
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	77	2,142	2,065	6,900
2013	7,457	138	36	(102)	800	1,203	403	6,883
2014	7,469	139	17	(122)	698	1,346	648	6,894
2015	7,479	139	23	(116)	135	1,943	1,807	6,903
2016	7,488	139	19	(120)	609	375	(234)	6,911
2017	7,505	139	28	(111)	764	298	(466)	6,927
2018	7,536	139	37	(102)	609	324	(284)	6,955
2019	7,571	139	36	(103)	843	279	(564)	6,988
2020	7,604	139	34	(106)	604	350	(254)	7,019
2021	7,648	288	34	(254)	563	396	(167)	7,059
2022	7,695	288	34	(254)	577	367	(209)	7,102
2023	7,744	288	34	(254)	860	259	(601)	7,148
2024	7,798	289	34	(255)	829	259	(571)	7,198
2025	7,846	288	34	(254)	442	1,362	920	7,242
2026	7,896	288	34	(254)	366	1,324	958	7,288
2027	7,947	288	34	(254)	408	1,391	983	7,335
2028	7,999	289	34	(255)	408	1,269	861	7,383
2029	8,044	288	34	(254)	437	1,173	736	7,425
2030	8,093	288	34	(254)	438	1,249	811	7,470
2031	8,143	288	34	(254)	484	1,152	668	7,516
2032	8,195	289	34	(255)	442	1,282	840	7,564
2033	8,241	288	34	(254)	418	1,223	805	7,606
2034	8,289	288	34	(254)	362	1,213	851	7,651
2035	8,339	288	34	(254)	472	1,041	569	7,697
2036	8,389	289	34	(255)	441	1,050	609	7,743
2037	8,439	288	34	(254)	347	1,111	764	7,789
2038	8,488	288	34	(254)	425	983	558	7,835
2039	8,538	288	34	(254)	374	1,047	673	7,881
2040	8,589	289	34	(255)	435	948	514	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR No Carbon Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Market Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures		Surplus MW	ICAP Value $/MW-Wk
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)			
2011	198,123	(12,786)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,693	(21,043)	94,720	177,017	0	0	0	177,017	87,010	264,027	0	264,027	420,444	0	2012	0	388
2013	228,697	(29,787)	37,019	221,464	0	(1)	(1)	221,464	51,794	273,257	0	273,257	651,966	0	2013	0	161
2014	275,667	(38,373)	57,276	256,764	607	0	607	257,371	102,292	359,662	1,379	358,283	931,386	607	2014	45	595
2015	276,036	(51,199)	45,765	281,470	607	(0)	607	282,077	29,834	311,911	(17,667)	329,577	1,167,977	607	2015	(225)	1,507
2016	266,504	(48,243)	(4,359)	319,105	219,322	33,403	252,725	571,830	1,731	573,561	(3,454)	577,015	1,549,251	219,322	2016	(34)	1,973
2017	265,548	(46,585)	(18,621)	330,755	219,322	42,313	261,635	592,390	983	593,373	(1,622)	594,995	1,911,140	219,322	2017	(18)	1,687
2018	277,382	(47,168)	(9,326)	333,876	219,322	42,990	262,312	596,188	398	596,585	(1,918)	598,503	2,246,212	219,322	2018	(26)	1,438
2019	276,066	(46,833)	(24,759)	347,659	219,322	43,762	263,084	610,742	153	610,895	(2,526)	613,421	2,562,324	219,322	2019	(30)	1,614
2020	282,098	(47,661)	(9,282)	339,040	226,653	44,582	271,235	610,276	0	610,276	(3,279)	613,555	2,853,359	226,653	2020	(34)	1,830
2021	285,909	(62,200)	(4,740)	352,849	226,653	45,402	272,055	624,904	0	624,904	(3,745)	628,649	3,127,839	226,653	2021	(35)	2,065
2022	288,731	(62,212)	(7,729)	358,672	226,653	46,311	272,964	631,636	0	631,636	(5,483)	637,119	3,383,894	226,653	2022	(47)	2,255
2023	287,424	(62,479)	(29,891)	379,794	226,653	47,274	273,927	653,721	0	653,721	(6,700)	660,420	3,628,205	226,653	2023	(53)	2,420
2024	298,739	(62,838)	(28,701)	390,277	226,653	48,225	274,878	665,155	0	665,155	(8,355)	673,511	3,857,544	226,653	2024	(63)	2,552
2025	376,794	(57,705)	88,731	345,768	329,505	65,481	394,986	740,754	0	740,754	45,121	695,632	4,075,577	329,505	2025	326	2,664
2026	392,595	(58,785)	89,106	362,273	329,505	68,035	397,540	759,814	0	759,814	44,923	714,891	4,281,827	329,505	2026	313	2,762
2027	400,822	(59,361)	93,086	367,097	329,505	68,974	398,479	765,577	0	765,577	44,249	721,328	4,473,384	329,505	2027	300	2,839
2028	410,546	(60,431)	85,817	385,161	329,505	70,936	400,441	785,602	0	785,602	43,457	742,145	4,654,794	329,505	2028	289	2,892
2029	418,969	(61,764)	78,210	402,524	329,505	72,737	402,242	804,765	0	804,765	42,382	762,383	4,826,331	329,505	2029	279	2,919
2030	425,018	(61,994)	84,463	402,548	329,505	73,641	403,146	805,695	0	805,695	40,697	764,998	4,984,768	329,505	2030	267	2,927
2031	433,327	(63,435)	74,403	422,359	329,505	75,934	405,439	827,798	0	827,798	38,672	789,126	5,135,203	329,505	2031	253	2,936
2032	443,793	(63,784)	88,573	419,003	329,505	76,928	406,433	825,437	0	825,437	37,297	788,140	5,273,502	329,505	2032	244	2,944
2033	452,378	(64,824)	86,584	430,618	329,505	78,652	408,157	838,774	0	838,774	33,689	805,085	5,403,539	329,505	2033	219	2,953
2034	465,840	(65,921)	89,601	442,160	329,505	80,611	410,116	852,276	0	852,276	32,789	819,487	5,525,376	329,505	2034	213	2,962
2035	468,511	(67,608)	69,516	466,603	329,505	82,968	412,473	879,076	0	879,076	31,668	847,409	5,641,344	329,505	2035	205	2,970
2036	480,311	(68,819)	74,480	474,650	329,505	84,777	414,282	888,932	0	888,932	30,087	858,845	5,749,530	329,505	2036	194	2,979
2037	491,831	(68,943)	84,507	476,268	329,505	86,014	415,519	891,787	0	891,787	27,489	864,297	5,849,744	329,505	2037	177	2,988
2038	496,115	(70,668)	72,287	494,496	329,505	88,159	417,664	912,160	0	912,160	25,550	886,610	5,944,370	329,505	2038	164	2,996
2039	509,978	(71,380)	81,900	499,457	329,505	90,056	419,561	919,018	0	919,018	23,767	895,251	6,032,319	329,505	2039	152	3,005
2040	514,943	(72,980)	69,443	518,480	329,505	92,401	421,906	940,385	0	940,385	24,176	916,210	6,115,169	329,505	2040	154	3,014
2011 Net Present Value																	
Period of 2011-2040	3,508,215	(537,051)	416,466	3,628,801	1,927,380	406,626	2,334,006	5,962,807	234,626	6,197,433	82,264	6,115,169					
Base Case O&M 2011-2040							611,621			611,621	0	611,621					
Utility Cost Present Value 2011-2040							2,945,627			6,809,054	82,264	6,726,790					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR No Carbon Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,381	6,969	0.34
2013	7,356	6,808	5,832	0.29
2014	5,011	6,985	5,268	0.33
2015	9,351	7,377	3,886	0.28
2016	4,097	4,214	1,639	0.01
2017	4,430	4,065	1,816	0.01
2018	4,358	4,280	1,797	0.01
2019	3,557	4,059	1,508	0.01
2020	4,573	4,372	768	0.00
2021	4,372	4,360	766	0.00
2022	4,559	4,361	766	0.00
2023	4,269	4,042	696	0.00
2024	3,655	4,111	711	0.00
2025	4,559	4,808	808	0.00
2026	3,917	4,745	783	0.00
2027	4,558	4,871	814	0.00
2028	3,884	4,737	781	0.00
2029	4,401	4,630	755	0.00
2030	4,332	4,809	799	0.00
2031	3,536	4,639	756	0.00
2032	4,572	4,912	819	0.00
2033	4,374	4,913	819	0.00
2034	4,558	4,949	823	0.00
2035	4,270	4,663	758	0.00
2036	3,658	4,739	774	0.00
2037	4,559	4,966	826	0.00
2038	3,917	4,812	792	0.00
2039	4,558	4,977	827	0.00
2040	3,886	4,821	792	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	77	2,142	2,065	6,900
2013	7,457	138	36	(102)	800	1,203	403	6,883
2014	7,469	139	17	(122)	698	1,346	648	6,894
2015	7,479	139	23	(116)	255	1,252	997	6,903
2016	7,488	139	19	(120)	564	418	(146)	6,911
2017	7,505	139	28	(111)	712	330	(382)	6,927
2018	7,536	139	37	(102)	564	362	(201)	6,955
2019	7,571	139	36	(103)	786	313	(474)	6,988
2020	7,604	139	34	(106)	563	389	(174)	7,019
2021	7,648	288	34	(254)	525	438	(87)	7,059
2022	7,695	288	34	(254)	538	402	(136)	7,102
2023	7,744	288	34	(254)	805	289	(516)	7,148
2024	7,798	289	34	(255)	773	290	(484)	7,198
2025	7,846	288	34	(254)	440	1,419	979	7,242
2026	7,896	288	34	(254)	354	1,388	1,034	7,288
2027	7,947	288	34	(254)	405	1,455	1,049	7,335
2028	7,999	289	34	(255)	400	1,329	930	7,383
2029	8,044	288	34	(254)	419	1,233	814	7,425
2030	8,093	288	34	(254)	433	1,308	876	7,470
2031	8,143	288	34	(254)	471	1,212	741	7,516
2032	8,195	289	34	(255)	436	1,341	905	7,564
2033	8,241	288	34	(254)	406	1,281	875	7,606
2034	8,289	288	34	(254)	354	1,275	921	7,651
2035	8,339	288	34	(254)	463	1,101	639	7,697
2036	8,389	289	34	(255)	425	1,114	688	7,743
2037	8,439	288	34	(254)	351	1,166	814	7,789
2038	8,488	288	34	(254)	410	1,044	634	7,835
2039	8,538	288	34	(254)	357	1,109	752	7,881
2040	8,589	289	34	(255)	427	1,001	574	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 the BS2 Replacement CC Added FT_CSAPR No Carbon Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts											ICAP	
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,693	(21,043)	94,720	177,017	0	0	0	177,017	87,010	264,027	0	264,027	420,444	0	2012	0	388
2013	228,697	(29,787)	37,019	221,464	0	(1)	(1)	221,464	51,794	273,257	0	273,257	651,966	0	2013	0	161
2014	275,667	(38,373)	57,276	256,764	607	0	607	257,371	102,292	359,662	1,379	358,283	931,386	607	2014	45	595
2015	276,036	(51,199)	45,765	281,470	607	0	607	282,077	29,834	311,911	(17,667)	329,577	1,167,977	607	2015	(225)	1,507
2016	72,505	(39,840)	(264,283)	376,628	36,583	0	36,583	413,211	1,596	414,807	(96,221)	511,027	1,505,649	36,583	2016	(938)	1,973
2017	69,730	(38,706)	(277,966)	386,402	36,583	0	36,583	422,985	895	423,880	(80,918)	504,798	1,812,678	36,583	2017	(922)	1,687
2018	76,949	(38,318)	(272,823)	388,090	36,583	0	36,583	424,673	359	425,032	(69,503)	494,535	2,089,543	36,583	2018	(930)	1,438
2019	71,023	(37,703)	(293,310)	402,037	36,583	0	36,583	438,620	136	438,756	(78,396)	517,152	2,356,045	36,583	2019	(934)	1,614
2020	282,003	(47,661)	(9,396)	339,060	238,249	44,574	282,823	621,883	0	621,883	(3,279)	625,162	2,652,586	238,249	2020	(34)	1,830
2021	285,676	(62,200)	(4,778)	352,854	238,249	45,399	283,648	636,502	0	636,502	(3,745)	640,247	2,932,130	238,249	2021	(35)	2,055
2022	288,805	(62,212)	(7,639)	358,656	238,249	46,318	284,567	643,222	0	643,222	(5,483)	648,705	3,192,841	238,249	2022	(47)	2,255
2023	287,424	(62,479)	(29,891)	379,794	238,249	47,274	285,523	665,317	0	665,317	(6,700)	672,016	3,441,442	238,249	2023	(53)	2,420
2024	298,774	(62,838)	(28,657)	390,269	238,249	48,228	286,477	676,746	0	676,746	(8,355)	685,101	3,674,728	238,249	2024	(63)	2,552
2025	376,756	(57,705)	88,692	345,769	341,101	65,478	406,579	752,348	0	752,348	45,121	707,226	3,896,395	341,101	2025	326	2,664
2026	392,595	(58,785)	80,106	352,273	341,101	68,035	409,136	771,410	0	771,410	44,923	726,487	4,105,991	341,101	2026	313	2,762
2027	400,822	(59,361)	93,086	367,097	341,101	68,974	410,075	777,173	0	777,173	44,249	732,924	4,300,627	341,101	2027	300	2,839
2028	410,546	(60,431)	85,817	385,161	341,101	70,936	412,037	797,198	0	797,198	43,457	753,741	4,484,872	341,101	2028	289	2,892
2029	418,969	(61,764)	78,210	402,524	341,101	72,737	413,838	816,361	0	816,361	42,382	773,979	4,659,018	341,101	2029	279	2,919
2030	425,057	(61,994)	84,504	402,546	341,101	73,645	414,746	817,292	0	817,292	40,697	776,595	4,819,856	341,101	2030	267	2,927
2031	433,327	(63,435)	74,403	422,359	341,101	75,934	417,035	839,394	0	839,394	38,672	800,722	4,972,503	341,101	2031	253	2,936
2032	443,793	(63,784)	88,573	419,003	341,101	76,928	418,029	837,033	0	837,033	37,297	799,736	5,112,836	341,101	2032	244	2,944
2033	452,378	(64,824)	86,584	430,618	341,101	78,652	419,753	850,370	0	850,370	33,689	816,681	5,244,746	341,101	2033	219	2,953
2034	465,880	(65,921)	89,645	442,157	341,101	80,615	421,716	863,873	0	863,873	32,789	831,083	5,368,307	341,101	2034	213	2,962
2035	468,643	(67,608)	69,655	466,596	341,101	82,981	424,082	890,677	0	890,677	31,668	859,010	5,485,863	341,101	2035	205	2,970
2036	480,425	(68,819)	74,600	474,644	341,101	84,787	425,888	900,532	0	900,532	30,087	870,446	5,595,510	341,101	2036	194	2,979
2037	491,831	(68,943)	84,507	476,268	341,101	86,014	427,115	903,383	0	903,383	27,489	875,893	5,697,069	341,101	2037	177	2,988
2038	496,182	(70,672)	72,360	494,494	341,101	88,165	429,266	923,760	0	923,760	25,550	898,210	5,792,933	341,101	2038	164	2,996
2039	509,959	(71,380)	81,880	499,459	341,101	90,054	431,155	930,614	0	930,614	23,767	906,846	5,682,021	341,101	2039	152	3,005
2040	514,832	(72,980)	69,324	518,488	341,101	92,390	433,491	951,978	0	951,978	24,176	927,803	5,965,919	341,101	2040	154	3,014
2011 Net Present Value																	
Period of 2011-2040	3,043,062	(517,047)	(198,922)	3,759,031	1,556,036	312,201	1,868,237	5,627,268	234,453	5,861,721	(104,198)	5,965,919					
Base Case O&M 2011-2040							611,621			611,621	0	611,621					
Utility Cost Present Value 2011-2040							2,479,858			6,473,342	(104,198)	6,577,540					

KPCo Capacity Resource Optimization

Costs and Emissions Summary

Levelized Market Replacement to 2020 the BS2 Replacement CC Added FT_CSAPR No Carbon Commodity Pricin

	SO2 *Emissions* ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,381	6,969	0.34
2013	7,356	6,808	5,832	0.29
2014	5,011	6,965	5,268	0.33
2015	9,351	7,377	3,886	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	4,371	767	0.00
2021	4,372	4,360	766	0.00
2022	4,559	4,362	766	0.00
2023	4,269	4,042	696	0.00
2024	3,655	4,112	711	0.00
2025	4,559	4,808	808	0.00
2026	3,917	4,745	783	0.00
2027	4,558	4,871	814	0.00
2028	3,884	4,737	781	0.00
2029	4,401	4,630	755	0.00
2030	4,332	4,809	799	0.00
2031	3,536	4,639	756	0.00
2032	4,572	4,912	819	0.00
2033	4,374	4,913	819	0.00
2034	4,558	4,949	823	0.00
2035	4,270	4,664	758	0.00
2036	3,658	4,740	774	0.00
2037	4,559	4,966	826	0.00
2038	3,917	4,813	792	0.00
2039	4,558	4,977	827	0.00
2040	3,886	4,820	792	0.00

	Summary of Energy Purchases and Sales (Gwh							Internal Requirement 0.923 GWh
	Internal *Requirements*	Contract *Purchases*	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	77	2,142	2,065	6,900
2013	7,457	138	36	(102)	800	1,203	403	6,883
2014	7,469	139	17	(122)	698	1,346	648	6,894
2015	7,479	139	23	(116)	255	1,252	997	6,903
2016	7,488	139	19	(120)	4,619		(4,619)	6,911
2017	7,505	139	28	(111)	4,775		(4,775)	6,927
2018	7,536	139	37	(102)	4,576		(4,576)	6,955
2019	7,571	139	36	(103)	4,862		(4,862)	6,988
2020	7,604	139	34	(106)	565	389	(176)	7,019
2021	7,648	288	34	(254)	525	438	(88)	7,059
2022	7,695	288	34	(254)	537	403	(134)	7,102
2023	7,744	288	34	(254)	805	289	(516)	7,148
2024	7,798	289	34	(255)	772	290	(483)	7,198
2025	7,846	288	34	(254)	441	1,419	978	7,242
2026	7,896	288	34	(254)	354	1,388	1,034	7,288
2027	7,947	288	34	(254)	405	1,455	1,049	7,335
2028	7,999	289	34	(255)	400	1,329	930	7,383
2029	8,044	288	34	(254)	419	1,233	814	7,425
2030	8,093	288	34	(254)	433	1,309	877	7,470
2031	8,143	288	34	(254)	471	1,212	741	7,516
2032	8,195	289	34	(255)	436	1,341	905	7,564
2033	8,241	288	34	(254)	406	1,281	875	7,606
2034	8,289	288	34	(254)	354	1,276	921	7,651
2035	8,339	288	34	(254)	460	1,101	641	7,697
2036	8,389	289	34	(255)	424	1,114	690	7,743
2037	8,439	288	34	(254)	351	1,166	814	7,789
2038	8,488	288	34	(254)	408	1,044	635	7,835
2039	8,538	288	34	(254)	358	1,109	752	7,881
2040	8,589	289	34	(255)	429	1,001	572	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	1,288	1 -904 MW NGCC,	0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 the BS2 Replacement CC Added FT_CSAPR No Carbon Commodity Pricing 10_31_11

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	198,123	(12,788)	40,914	169,997	0	(0)	(0)	169,997	7,418	177,415	0	177,415	177,415	0	2011	0	958
2012	250,693	(21,043)	94,720	177,017	0	0	0	177,017	87,010	264,027	0	264,027	420,444	0	2012	0	388
2013	228,697	(29,787)	37,019	221,464	0	(1)	(1)	221,464	51,794	273,257	0	273,257	651,966	0	2013	0	161
2014	275,667	(38,373)	57,276	256,764	607	0	607	257,371	102,292	359,662	1,379	358,283	931,386	607	2014	45	595
2015	276,036	(51,199)	45,765	281,470	607	(0)	607	282,077	29,834	311,911	(17,667)	329,577	1,167,977	607	2015	(225)	1,507
2016	72,505	(39,840)	(264,283)	376,628	36,583	0	36,583	413,211	1,596	414,807	(96,221)	511,027	1,505,649	36,583	2016	(938)	1,973
2017	69,730	(38,706)	(277,966)	386,402	36,583	0	36,583	422,985	895	423,880	(80,918)	504,798	1,812,677	35,583	2017	(922)	1,687
2018	76,949	(38,318)	(272,823)	388,090	36,583	0	36,583	424,673	359	425,032	(69,503)	494,535	2,089,543	36,583	2018	(930)	1,438
2019	71,023	(37,703)	(293,311)	402,037	36,583	0	36,583	438,620	136	438,756	(78,396)	517,153	2,356,045	36,583	2019	(934)	1,614
2020	75,257	(38,513)	(279,832)	393,602	43,914	0	43,914	437,516	0	437,516	(89,317)	526,833	2,605,945	43,914	2020	(938)	1,830
2021	76,468	(52,947)	(278,336)	407,751	43,914	0	43,914	451,665	0	451,665	(100,833)	552,498	2,847,176	43,914	2021	(939)	2,065
2022	76,760	(52,927)	(286,068)	415,755	43,914	0	43,914	459,669	0	459,669	(111,498)	571,168	3,076,725	43,914	2022	(951)	2,255
2023	69,002	(53,954)	(316,832)	439,788	43,914	0	43,914	483,702	0	483,702	(120,464)	604,166	3,300,226	43,914	2023	(957)	2,420
2024	72,372	(54,367)	(321,132)	447,871	43,914	0	43,914	491,785	0	491,785	(128,323)	620,108	3,511,380	43,914	2024	(967)	2,552
2025	376,794	(57,705)	88,731	345,768	356,636	65,481	422,117	767,885	0	767,885	45,121	722,763	3,737,918	356,636	2025	326	2,664
2026	392,595	(58,785)	89,106	362,273	356,636	68,035	424,671	786,945	0	786,945	44,923	742,022	3,951,995	356,636	2026	313	2,762
2027	400,822	(59,361)	93,086	367,097	356,636	68,974	425,610	792,708	0	792,708	44,249	748,459	4,150,756	356,636	2027	300	2,839
2028	410,546	(60,431)	85,817	385,161	356,636	70,936	427,572	812,733	0	812,733	43,457	769,276	4,338,799	356,636	2028	289	2,892
2029	418,969	(61,764)	78,210	402,524	356,636	72,737	429,373	831,896	0	831,896	42,382	789,514	4,516,440	356,636	2029	279	2,919
2030	425,018	(61,994)	84,463	402,548	356,636	73,641	430,277	832,826	0	832,826	40,697	792,129	4,680,496	356,636	2030	267	2,927
2031	433,327	(63,435)	74,403	422,359	356,636	75,934	432,570	854,929	0	854,929	38,672	816,257	4,836,104	356,636	2031	253	2,936
2032	443,793	(63,784)	88,573	419,003	356,636	76,928	433,564	852,568	0	852,568	37,297	815,271	4,979,163	356,636	2032	244	2,944
2033	452,378	(64,824)	86,584	430,618	356,636	78,652	435,288	865,905	0	865,905	33,689	832,216	5,113,583	356,636	2033	219	2,953
2034	465,840	(65,921)	89,601	442,160	356,636	80,611	437,247	879,407	0	879,407	32,789	846,618	5,239,453	356,636	2034	213	2,962
2035	468,511	(67,608)	69,516	466,603	356,636	82,968	439,604	906,207	0	906,207	31,668	874,540	5,359,134	356,636	2035	205	2,970
2036	480,311	(68,819)	74,480	474,650	356,636	84,777	441,413	916,063	0	916,063	30,087	885,976	5,470,737	356,636	2036	194	2,979
2037	491,831	(68,943)	84,507	476,268	356,636	86,014	442,650	918,918	0	918,918	27,489	891,428	5,574,097	356,636	2037	177	2,988
2038	496,115	(70,668)	72,287	494,496	356,636	88,159	444,795	939,291	0	939,291	25,550	913,741	5,671,619	356,636	2038	164	2,996
2039	509,978	(71,380)	81,900	499,457	356,636	90,056	446,692	946,149	0	946,149	23,767	922,382	5,762,233	356,636	2039	152	3,005
2040	514,943	(72,980)	69,443	518,480	356,636	92,401	449,037	967,516	0	967,516	24,176	943,341	5,847,536	356,636	2040	154	3,014
2011 Net Present Value																	
Period of 2011-2040	2,610,418	(498,898)	(764,313)	3,873,629	1,207,804	218,707	1,426,511	5,300,141	234,453	5,534,594	(312,943)	5,847,536					
Base Case O&M 2011-2040							611,621			611,621	0	611,621					
Utility Cost Present Value 2011-2040							2,038,132			6,146,215	(312,943)	6,459,157					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 the BS2 Replacement CC Added FT_CSAPR No Carbon Commodity Pricing 10_31_11

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,381	6,969	0.34
2013	7,356	6,808	5,832	0.29
2014	5,011	6,985	5,268	0.33
2015	9,351	7,377	3,886	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	2,783	597	0.00
2021	4,372	2,775	595	0.00
2022	4,559	2,775	595	0.00
2023	4,269	2,449	525	0.00
2024	3,655	2,513	539	0.00
2025	4,559	4,808	808	0.00
2026	3,917	4,745	783	0.00
2027	4,558	4,871	814	0.00
2028	3,884	4,737	781	0.00
2029	4,401	4,630	755	0.00
2030	4,332	4,809	799	0.00
2031	3,536	4,639	756	0.00
2032	4,572	4,912	819	0.00
2033	4,374	4,913	819	0.00
2034	4,558	4,949	823	0.00
2035	4,270	4,663	758	0.00
2036	3,658	4,739	774	0.00
2037	4,559	4,966	826	0.00
2038	3,917	4,812	792	0.00
2039	4,558	4,977	827	0.00
2040	3,886	4,821	792	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	77	2,142	2,065	6,900
2013	7,457	138	36	(102)	800	1,203	403	6,883
2014	7,469	139	17	(122)	698	1,346	648	6,894
2015	7,479	139	23	(116)	255	1,252	997	6,903
2016	7,488	139	19	(120)	4,619		(4,619)	6,911
2017	7,505	139	28	(111)	4,775		(4,775)	6,927
2018	7,536	139	37	(102)	4,576		(4,576)	6,955
2019	7,571	139	36	(103)	4,862		(4,862)	6,988
2020	7,604	139	34	(106)	4,561		(4,561)	7,019
2021	7,648	288	34	(254)	4,462		(4,462)	7,059
2022	7,695	288	34	(254)	4,511		(4,511)	7,102
2023	7,744	288	34	(254)	4,909		(4,909)	7,148
2024	7,798	289	34	(255)	4,888		(4,888)	7,198
2025	7,846	288	34	(254)	440	1,419	979	7,242
2026	7,896	288	34	(254)	354	1,388	1,034	7,288
2027	7,947	288	34	(254)	405	1,455	1,049	7,335
2028	7,999	289	34	(255)	400	1,329	930	7,383
2029	8,044	288	34	(254)	419	1,233	814	7,425
2030	8,093	288	34	(254)	433	1,308	876	7,470
2031	8,143	288	34	(254)	471	1,212	741	7,516
2032	8,195	289	34	(255)	436	1,341	905	7,564
2033	8,241	288	34	(254)	406	1,281	875	7,606
2034	8,289	288	34	(254)	354	1,275	921	7,651
2035	8,339	288	34	(254)	463	1,101	639	7,697
2036	8,389	289	34	(255)	425	1,114	688	7,743
2037	8,439	288	34	(254)	351	1,166	814	7,789
2038	8,488	288	34	(254)	410	1,044	634	7,835
2039	8,538	288	34	(254)	357	1,109	752	7,881
2040	8,589	289	34	(255)	427	1,001	574	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,303	1- 407 MW CC,1 -904 MW NGCC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

Big Sandy Unit 2 under: "Fleet Transition-Early Carbon" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013					
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	225 MW- ICAP	225 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				1 -904 MW NGCC	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1- 407 MW CC
2026 ~ 2040					

Life-Cycle Analysis Period (2011-2040) ($000)					
CPW of Revenue Requirements	7,096,011	7,461,072	7,386,922	7,127,793	6,803,200
Less: ICAP Revenue	(111,660)	72,971	(11,072)	(100,168)	(289,247)
CPW of Revenue Requirements, Net	7,207,670	7,388,101	7,397,994	7,227,961	7,092,447
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		365,062	290,912	31,782	(292,810)
Less: ICAP / Pool Revenue		184,631	100,588	11,491	(177,587)
CPW of Revenue Requirements, Net		180,431	190,324	20,291	(115,223)
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year) *RETROFIT Cost Recovery*		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		217,631	227,524	57,491	(78,023)

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a 15-year recovery period for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...
  Inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Big Sandy 2 UD Analysis Under FT_CSAPR Early Carbon Commodity Pricing
Capacity Resource Optimization
Expansion Plan Summary

	Retrofit 15 yr book life 30 Year Operating Life	***BS1 Repower 20 yr book life*** 30 Year Operating Life	***NGCC Replacement*** 30 Book/30 Operating	***Market to 2020***	***Market to 2025***
2011				0 MW- ICAP	0 MW- ICAP
2012				0 MW- ICAP	0 MW- ICAP
2013				0 MW- ICAP	0 MW- ICAP
2014				45 MW- ICAP	45 MW- ICAP
2015	Big Sandy 1 Retire		Big Sandy 1 Retire	225 MW- ICAP	225 MW- ICAP
2016	**Big Sandy 2 Retrofit**	**Big Sandy 1 Retire**	**1 -904 MW NGCC**	938 MW- ICAP	938 MW- ICAP
		1 -780 MW Repower,			
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				**1 -904 MW NGCC**	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
					1 -904 MW NGCC, 1-
2025	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**1- 407 MW CC,**	**407 MW CC**
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

	Retrofit 15 yr book life	*BS1 Repower 20 yr book life*	*NGCC Replacement*	*Market to 2020*	*Market to 2025*
FTCA_CSAPR					
Early Carbon					
CPW	7,096,011	7,386,922	7,461,072	7,127,793	6,803,200
ICAP Revenue	(111,660)	(11,072)	72,971	(100,168)	(289,247)
Total	$7,207,670	$7,397,994	$7,388,101	$7,227,961	$7,092,447
Cost Over Retrofit		$190,324	$180,431	$20,291	($115,223)

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR Early Carbon Commodity Pricing, Big Sandy 2 Retrofit

Optimal Plan Cost Summary ($000)

					Base Rate Impacts												ICAP
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	Value $/MW-Wk
2011	227,807	(12,788)	40,914	199,680	0	0	0	199,680	7,418	207,098	0	207,098	207,098	0	2011	0	958
2012	255,302	(20,951)	94,814	181,439	0	0	0	181,439	87,229	268,668	0	268,668	454,399	0	2012	0	388
2013	228,766	(29,661)	31,279	227,148	0	0	0	227,148	50,469	277,617	0	277,617	689,615	0	2013	0	161
2014	273,936	(38,307)	56,211	256,032	607	0	607	256,639	102,971	359,609	1,379	358,230	968,993	607	2014	45	595
2015	275,726	(50,969)	44,815	281,880	607	0	607	282,487	29,797	312,285	(17,667)	329,951	1,205,853	607	2015	(225)	1,507
2016	163,386	(47,534)	(85,865)	296,785	147,762	76,404	224,166	520,951	2,299	523,250	(96,221)	619,471	1,615,181	147,762	2016	(938)	1,973
2017	230,156	(54,248)	29,271	255,133	147,762	136,766	284,528	539,661	106,271	645,932	(13,657)	659,589	2,016,357	147,762	2017	(178)	1,477
2018	247,521	(55,973)	55,369	248,125	147,762	148,265	296,027	544,152	113,063	657,216	(12,406)	669,621	2,391,244	147,762	2018	(189)	1,263
2019	234,881	(57,514)	20,902	271,494	147,762	138,664	286,426	557,919	106,634	664,553	(15,411)	679,964	2,741,647	147,762	2019	(197)	1,502
2020	258,857	(58,911)	55,313	262,454	155,093	139,551	294,644	557,098	116,137	673,235	(18,222)	691,457	3,069,635	155,093	2020	(206)	1,704
2021	262,664	(73,727)	61,313	275,078	155,093	142,922	298,015	573,093	117,336	690,429	(19,878)	710,307	3,379,768	155,093	2021	(206)	1,855
2022	261,078	(73,998)	44,337	290,740	155,093	143,753	298,846	589,586	115,517	705,103	(22,938)	728,041	3,672,364	155,093	2022	(218)	2,024
2023	234,463	(72,143)	(26,520)	333,125	155,093	140,223	295,316	628,442	102,575	731,017	(25,381)	756,398	3,952,181	155,093	2023	(224)	2,175
2024	261,513	(77,050)	19,088	319,475	155,093	149,930	305,023	624,498	113,851	738,349	(28,087)	766,435	4,213,161	155,093	2024	(234)	2,307
2025	345,162	(60,653)	135,776	270,039	257,945	166,923	424,868	694,907	124,359	819,266	19,441	799,825	4,463,852	257,945	2025	155	2,419
2026	361,796	(61,712)	155,874	267,634	257,945	176,435	434,380	702,015	130,682	832,697	18,482	814,214	4,698,757	257,945	2026	142	2,510
2027	360,276	(62,987)	133,328	289,935	257,945	174,665	432,610	722,544	127,680	850,224	17,019	833,205	4,920,024	257,945	2027	129	2,545
2028	377,519	(63,701)	156,165	285,055	257,945	184,718	442,663	727,718	134,175	861,893	15,874	846,019	5,126,826	257,945	2028	118	2,591
2029	380,371	(64,906)	140,266	305,011	257,945	188,124	446,069	751,080	132,975	884,055	14,674	869,381	5,322,437	257,945	2029	108	2,611
2030	375,874	(64,262)	112,106	328,030	257,945	184,426	442,371	770,401	128,570	898,971	13,034	885,937	5,505,921	257,945	2030	96	2,605
2031	392,618	(66,783)	137,243	322,158	146,766	148,300	295,066	617,224	136,421	753,645	11,216	742,430	5,647,455	146,766	2031	82	2,625
2032	414,589	(66,993)	161,645	319,936	146,766	149,515	296,281	616,217	144,207	760,424	9,964	750,461	5,779,142	146,766	2032	72	2,645
2033	421,631	(67,973)	158,650	330,954	146,766	149,142	295,908	626,862	145,759	772,621	6,685	765,936	5,902,855	146,766	2033	48	2,665
2034	410,211	(68,613)	110,045	368,779	146,766	144,368	291,134	659,913	136,816	796,729	5,831	790,898	6,020,442	146,766	2034	42	2,685
2035	428,356	(71,520)	129,259	370,617	146,766	156,414	303,180	673,797	143,386	817,183	4,766	812,418	6,131,621	146,766	2035	34	2,706
2036	424,338	(72,989)	137,709	359,619	146,766	159,692	306,458	666,077	147,263	813,340	3,270	810,069	6,233,663	146,766	2036	23	2,726
2037	443,625	(73,151)	157,972	358,804	146,766	162,299	309,065	667,868	154,181	822,049	826	821,223	6,328,883	146,766	2037	6	2,747
2038	439,666	(75,402)	141,609	373,459	146,766	164,822	311,588	685,047	152,895	837,941	(1,033)	838,974	6,418,425	146,766	2038	(7)	2,768
2039	455,017	(76,100)	157,177	373,941	146,766	168,472	315,238	689,179	158,579	847,758	(2,764)	850,522	6,501,980	146,766	2039	(19)	2,789
2040	452,810	(77,913)	144,228	386,495	146,766	349,039	495,805	882,300	157,722	1,040,022	(2,470)	1,042,492	6,596,249	146,766	2040	(17)	2,810
2011 Net Present Value																	
Period of 2011-2040	3,230,665	(584,571)	710,399	3,104,837	1,257,570	1,078,816	2,336,386	5,441,223	1,043,366	6,484,589	(111,660)	6,596,249					
Base Case O&M 2011-2040							611,421			611,421	0	611,421					
Utility Cost Present Value 2011-2040							2,947,807			7,096,011	(111,660)	7,207,670					

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT CSAPR Early Carbon Commodity Pricing, Big Sandy 2 Retrofit

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,400	7,010	0.34
2013	7,446	6,696	5,317	0.29
2014	4,238	6,936	5,561	0.34
2015	9,351	7,370	3,885	0.28
2016	4,097	5,136	2,087	0.15
2017	4,430	6,948	2,743	0.26
2018	4,358	7,360	2,771	0.27
2019	3,557	6,875	2,418	0.26
2020	4,573	7,409	1,732	0.26
2021	4,372	7,387	1,727	0.26
2022	4,559	7,183	1,676	0.25
2023	4,269	6,296	1,469	0.22
2024	3,655	6,900	1,616	0.25
2025	4,559	7,437	1,662	0.24
2026	3,917	7,713	1,739	0.26
2027	4,558	7,439	1,662	0.24
2028	3,884	7,719	1,740	0.26
2029	4,401	7,554	1,706	0.26
2030	4,332	7,209	1,605	0.23
2031	3,536	7,551	1,705	0.26
2032	4,572	7,880	1,777	0.26
2033	4,374	7,863	1,773	0.26
2034	4,558	7,267	1,622	0.23
2035	4,270	7,539	1,703	0.26
2036	3,658	7,644	1,726	0.27
2037	4,559	7,900	1,780	0.27
2038	3,917	7,734	1,745	0.27
2039	4,558	7,919	1,784	0.27
2040	3,886	7,776	1,753	0.27

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	75	2,165	2,089	6,900
2013	7,457	138	36	(102)	840	1,095	255	6,883
2014	7,469	139	17	(122)	752	1,361	608	6,894
2015	7,479	139	23	(116)	258	1,242	984	6,903
2016	7,488	139	19	(120)	2,374	729	(1,644)	6,911
2017	7,505	139	28	(111)	346	821	475	6,927
2018	7,536	139	37	(102)	176	1,081	905	6,955
2019	7,571	139	36	(103)	382	725	342	6,988
2020	7,604	139	34	(106)	195	1,103	908	7,019
2021	7,648	288	34	(254)	182	1,163	981	7,059
2022	7,695	288	34	(254)	353	1,044	691	7,102
2023	7,744	288	34	(254)	821	455	(366)	7,148
2024	7,798	289	34	(255)	389	685	296	7,198
2025	7,846	288	34	(254)	186	1,780	1,594	7,242
2026	7,896	288	34	(254)	143	1,985	1,842	7,288
2027	7,947	288	34	(254)	302	1,818	1,516	7,335
2028	7,999	289	34	(255)	172	1,921	1,749	7,383
2029	8,044	288	34	(254)	209	1,711	1,502	7,425
2030	8,093	288	34	(254)	521	1,665	1,145	7,470
2031	8,143	288	34	(254)	220	1,627	1,407	7,516
2032	8,195	289	34	(255)	141	1,831	1,690	7,564
2033	8,241	288	34	(254)	185	1,816	1,631	7,606
2034	8,289	288	34	(254)	451	1,478	1,027	7,651
2035	8,339	288	34	(254)	256	1,456	1,200	7,697
2036	8,389	289	34	(255)	229	1,507	1,278	7,743
2037	8,439	288	34	(254)	181	1,689	1,507	7,789
2038	8,488	288	34	(254)	184	1,467	1,283	7,835
2039	8,538	288	34	(254)	152	1,591	1,439	7,881
2040	8,589	289	34	(255)	222	1,486	1,264	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373	Retrofit	0	373	-69.3%
2017	1,198	1,116		0	1,116	-6.8%
2018	1,207	1,115		0	1,115	-7.6%
2019	1,218	1,119		0	1,119	-8.2%
2020	1,224	1,117		0	1,117	-8.8%
2021	1,238	1,131		0	1,131	-8.6%
2022	1,249	1,131		0	1,131	-9.4%
2023	1,255	1,131		0	1,131	-9.8%
2024	1,264	1,131		0	1,131	-10.5%
2025	1,281	1,131	1- 407 MW CC,	407	1,538	20.1%
2026	1,293	1,131		407	1,538	19.0%
2027	1,305	1,131		407	1,538	17.9%
2028	1,315	1,131		407	1,538	17.0%
2029	1,324	1,131		407	1,538	16.2%
2030	1,335	1,131		407	1,538	15.2%
2031	1,348	1,131		407	1,538	14.1%
2032	1,357	1,131		407	1,538	13.4%
2033	1,372	1,123		407	1,530	11.6%
2034	1,378	1,123		407	1,530	11.1%
2035	1,389	1,127		407	1,534	10.5%
2036	1,399	1,127		407	1,534	9.7%
2037	1,415	1,127		407	1,534	8.4%
2038	1,427	1,127		407	1,534	7.5%
2039	1,438	1,127		407	1,534	6.7%
2040	1,436	1,127		407	1,534	6.9%

KENTUCKY POWER COMPANY

KPCo Capacity Resource Optimization

Costs and Emissions Summary

Levelized FT_CSAPR Early Carbon Commodity Pricing, Big Sandy 1 Repower 20_30

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	227,807	(12,788)	40,914	199,680	0	(0)	(0)	199,680	7,418	207,098	0	207,098	207,098	0
2012	255,302	(20,951)	94,814	181,439	0	(0)	(0)	181,439	87,229	268,668	0	268,668	454,399	0
2013	228,766	(29,661)	31,279	227,148	0	(0)	(0)	227,148	50,469	277,617	0	277,617	689,615	0
2014	273,936	(38,307)	56,211	256,032	607	0	607	256,639	102,971	359,609	1,379	358,230	968,993	607
2015	306,383	(45,487)	93,689	258,182	607	45,549	46,156	304,337	35,238	339,575	2,451	337,125	1,211,002	607
2016	260,192	(47,169)	(11,008)	318,368	216,791	33,244	250,035	568,403	1,727	570,130	(16,179)	586,309	1,598,418	216,791
2017	271,846	(47,412)	(24,116)	343,373	216,791	42,460	259,251	602,625	62,036	664,661	(10,943)	675,604	2,009,335	216,791
2018	282,533	(47,541)	(14,570)	344,644	216,791	43,219	260,010	604,654	65,472	670,126	(9,827)	679,952	2,390,006	216,791
2019	281,059	(46,878)	(31,886)	359,823	216,791	44,274	261,065	620,888	62,663	683,552	(12,035)	695,587	2,748,460	216,791
2020	296,493	(48,172)	(11,209)	355,874	224,122	45,396	269,518	625,393	68,385	693,778	(14,042)	707,820	3,084,210	224,122
2021	303,437	(62,431)	(9,346)	375,215	224,122	46,248	270,370	645,585	68,892	714,477	(15,328)	729,804	3,402,856	224,122
2022	310,568	(62,855)	(13,021)	386,444	224,122	47,307	271,429	657,873	69,766	727,639	(17,974)	745,613	3,702,514	224,122
2023	307,784	(62,636)	(39,170)	409,590	224,122	48,438	272,560	682,150	65,434	747,584	(20,047)	767,631	3,986,486	224,122
2024	314,742	(63,311)	(37,768)	415,821	224,122	49,605	273,727	689,548	67,424	756,972	(22,429)	779,401	4,251,882	224,122
2025	402,801	(58,228)	98,185	362,844	326,974	67,309	394,283	757,127	80,335	837,462	25,374	812,089	4,506,417	326,974
2026	418,177	(59,335)	99,525	377,987	326,974	70,104	397,078	775,065	80,311	855,376	24,638	830,738	4,746,089	326,974
2027	427,407	(59,945)	102,565	384,787	326,974	71,167	398,141	782,928	83,452	866,379	23,259	843,120	4,969,989	326,974
2028	437,547	(61,124)	96,896	401,775	326,974	73,475	400,449	802,225	82,339	884,563	22,227	862,336	5,180,779	326,974
2029	446,996	(62,605)	85,639	423,961	326,974	75,300	402,274	826,235	81,259	907,494	21,076	886,418	5,380,224	326,974
2030	454,501	(62,737)	94,727	422,511	326,974	76,595	403,569	826,080	85,700	911,780	19,422	892,358	5,565,037	326,974
2031	461,103	(64,263)	83,317	442,049	326,974	79,116	406,090	848,139	83,726	931,865	17,653	914,212	5,739,319	326,974
2032	476,379	(64,626)	100,906	440,099	326,974	80,444	407,418	847,517	89,898	937,415	16,449	920,966	5,900,925	326,974
2033	484,923	(65,666)	98,785	451,804	326,974	82,476	409,450	861,255	91,072	952,327	13,220	939,107	6,052,610	326,974
2034	500,679	(66,865)	103,133	464,411	326,974	84,792	411,766	876,177	92,938	969,116	12,415	956,700	6,194,846	326,974
2035	503,884	(68,677)	79,673	492,888	326,974	87,299	414,273	907,160	88,653	995,814	11,400	984,413	6,329,564	326,974
2036	511,635	(69,869)	83,747	497,756	146,766	89,229	235,995	733,751	91,039	824,790	9,956	814,835	6,432,206	146,766
2037	533,225	(70,288)	102,391	501,122	146,766	90,997	237,763	738,885	97,290	836,175	7,562	828,613	6,528,282	146,766
2038	532,280	(71,984)	83,627	520,637	146,766	92,854	239,620	760,258	95,103	855,361	5,754	849,607	6,618,959	146,766
2039	549,659	(72,612)	94,682	527,589	146,766	94,874	241,640	769,230	99,634	868,863	4,074	864,789	6,703,915	146,766
2040	554,557	(74,417)	82,657	546,317	146,766	127,506	274,272	820,590	97,907	918,497	4,421	914,076	6,786,572	146,766
2011 Net Present Value														
Period of 2011-2040	3,691,970	(535,952)	450,475	3,777,447	1,812,173	453,662	2,265,835	6,043,282	732,218	6,775,501	(11,072)	6,786,572		
Base Case O&M 2011-2040							611,421			611,421	0	611,421		
Utility Cost Present Value 2011-2040							2,877,256			7,386,922	(11,072)	7,397,994		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	31	1,507
2016	(158)	1,973
2017	(142)	1,477
2018	(150)	1,263
2019	(154)	1,502
2020	(158)	1,704
2021	(159)	1,855
2022	(171)	2,024
2023	(177)	2,175
2024	(187)	2,307
2025	202	2,419
2026	189	2,510
2027	176	2,545
2028	165	2,591
2029	155	2,611
2030	143	2,605
2031	129	2,625
2032	120	2,645
2033	95	2,665
2034	89	2,685
2035	81	2,706
2036	70	2,726
2037	53	2,747
2038	40	2,768
2039	28	2,789
2040	30	2,810

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FT_CSAPR Early Carbon Commodity Pricing, Big Sandy 1 Repower 20_30

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,400	7,010	0.34
2013	7,446	6,696	5,317	0.29
2014	4,238	6,936	5,561	0.34
2015	9,351	8,123	6,072	0.32
2016	4,097	4,172	1,635	0.01
2017	4,430	4,049	1,814	0.01
2018	4,358	4,259	1,795	0.01
2019	3,557	4,039	1,507	0.01
2020	4,573	4,363	767	0.00
2021	4,372	4,337	763	0.00
2022	4,559	4,338	763	0.00
2023	4,269	4,016	694	0.00
2024	3,655	4,086	709	0.00
2025	4,559	4,804	807	0.00
2026	3,917	4,740	782	0.00
2027	4,558	4,862	813	0.00
2028	3,884	4,737	781	0.00
2029	4,401	4,616	754	0.00
2030	4,332	4,805	798	0.00
2031	3,536	4,634	756	0.00
2032	4,572	4,912	820	0.00
2033	4,374	4,913	819	0.00
2034	4,558	4,950	823	0.00
2035	4,270	4,661	758	0.00
2036	3,658	4,725	772	0.00
2037	4,559	4,985	828	0.00
2038	3,917	4,811	792	0.00
2039	4,558	4,976	827	0.00
2040	3,886	4,827	793	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	75	2,165	2,089	6,900
2013	7,457	138	36	(102)	840	1,095	255	6,883
2014	7,469	139	17	(122)	752	1,361	608	6,894
2015	7,479	139	23	(116)	134	1,939	1,804	6,903
2016	7,488	139	19	(120)	629	362	(267)	6,911
2017	7,505	139	28	(111)	722	316	(405)	6,927
2018	7,536	139	37	(102)	587	343	(245)	6,955
2019	7,571	139	36	(103)	810	297	(513)	6,988
2020	7,604	139	34	(106)	560	387	(173)	7,019
2021	7,648	288	34	(254)	556	419	(137)	7,059
2022	7,695	288	34	(254)	568	384	(184)	7,102
2023	7,744	288	34	(254)	848	271	(577)	7,148
2024	7,798	289	34	(255)	813	271	(542)	7,198
2025	7,846	288	34	(254)	430	1,405	974	7,242
2026	7,896	288	34	(254)	353	1,383	1,030	7,288
2027	7,947	288	34	(254)	400	1,430	1,030	7,335
2028	7,999	289	34	(255)	394	1,329	936	7,383
2029	8,044	288	34	(254)	433	1,217	784	7,425
2030	8,093	288	34	(254)	429	1,304	875	7,470
2031	8,143	288	34	(254)	478	1,214	736	7,516
2032	8,195	289	34	(255)	439	1,354	916	7,564
2033	8,241	288	34	(254)	415	1,299	885	7,606
2034	8,289	288	34	(254)	362	1,301	939	7,651
2035	8,339	288	34	(254)	466	1,114	649	7,697
2036	8,389	289	34	(255)	455	1,126	673	7,743
2037	8,439	288	34	(254)	342	1,230	888	7,789
2038	8,488	288	34	(254)	422	1,071	649	7,835
2039	8,538	288	34	(254)	372	1,138	766	7,881
2040	8,589	289	34	(255)	427	1,039	612	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,364		0	1,364	10.6%
2016	1,213	1,153	1 -780 MW Repower,	0	1,153	-5.0%
2017	1,198	1,152		0	1,152	-3.9%
2018	1,207	1,154		0	1,154	-4.4%
2019	1,218	1,162		0	1,162	-4.6%
2020	1,224	1,164		0	1,164	-4.9%
2021	1,238	1,179		0	1,179	-4.8%
2022	1,249	1,179		0	1,179	-5.6%
2023	1,255	1,179		0	1,179	-6.1%
2024	1,264	1,179		0	1,179	-6.8%
2025	1,281	1,179	1- 407 MW CC,	407	1,586	23.8%
2026	1,293	1,179		407	1,586	22.6%
2027	1,305	1,179		407	1,586	21.5%
2028	1,315	1,179		407	1,586	20.6%
2029	1,324	1,179		407	1,586	19.8%
2030	1,335	1,179		407	1,586	18.8%
2031	1,348	1,179		407	1,586	17.6%
2032	1,357	1,179		407	1,586	16.9%
2033	1,372	1,171		407	1,578	15.0%
2034	1,378	1,171		407	1,578	14.5%
2035	1,389	1,175		407	1,582	13.9%
2036	1,399	1,175		407	1,582	13.1%
2037	1,415	1,175		407	1,582	11.8%
2038	1,427	1,175		407	1,582	10.8%
2039	1,438	1,175		407	1,582	10.0%
2040	1,436	1,175		407	1,582	10.1%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR Early Carbon Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	227,807	(12,788)	40,914	199,680	0	(0)	(0)	199,680	7,418	207,098	0	207,098	207,098	0
2012	255,302	(20,951)	94,814	181,439	0	(0)	(0)	181,439	87,229	268,668	0	268,668	454,399	0
2013	228,766	(29,661)	31,279	227,148	0	(0)	(0)	227,148	50,469	277,617	0	277,617	689,615	0
2014	273,936	(38,307)	56,211	256,032	607	0	607	256,639	102,971	359,609	1,379	358,230	968,993	607
2015	275,726	(50,969)	44,815	281,880	607	(0)	607	282,487	29,797	312,285	(17,667)	329,951	1,205,853	607
2016	264,055	(47,594)	(5,901)	317,549	219,322	33,332	252,654	570,204	1,730	571,933	(3,454)	575,388	1,586,052	219,322
2017	275,952	(47,792)	(18,184)	341,928	219,322	42,482	261,804	603,733	62,521	666,253	(1,420)	667,674	1,992,145	219,322
2018	286,633	(48,233)	(8,405)	343,271	219,322	43,102	262,424	605,695	65,948	671,644	(1,685)	673,328	2,369,108	219,322
2019	285,424	(47,869)	(25,250)	358,543	219,322	43,903	263,225	621,768	63,167	684,935	(2,351)	687,285	2,723,284	219,322
2020	300,686	(48,864)	(5,027)	354,578	226,653	44,830	271,483	626,061	68,871	694,932	(3,053)	697,985	3,054,368	226,653
2021	307,836	(62,937)	(3,122)	373,895	226,653	45,500	272,153	646,048	69,387	715,435	(3,364)	718,799	3,368,209	226,653
2022	314,699	(63,232)	(7,220)	385,151	226,653	46,377	273,030	658,182	70,228	728,410	(4,922)	733,331	3,662,932	226,653
2023	312,425	(63,221)	(32,571)	408,218	226,653	47,344	273,997	682,214	65,950	748,164	(6,021)	754,186	3,941,930	226,653
2024	319,471	(63,974)	(30,983)	414,429	226,653	48,305	274,958	689,387	67,945	757,332	(7,553)	764,886	4,202,383	226,653
2025	406,194	(57,945)	103,191	360,948	329,505	65,707	395,212	756,160	80,704	836,864	40,972	795,892	4,451,841	329,505
2026	422,838	(59,046)	105,942	375,942	329,505	68,371	397,876	773,818	80,818	854,635	40,824	813,811	4,686,630	329,505
2027	431,498	(59,683)	108,404	382,777	329,505	69,191	398,696	781,473	83,893	865,365	39,666	825,700	4,905,903	329,505
2028	442,087	(60,823)	103,199	399,711	329,505	71,307	400,812	800,523	82,824	883,347	38,934	844,414	5,112,313	329,505
2029	452,060	(62,288)	92,469	421,880	329,505	72,983	402,488	824,368	81,792	906,160	37,909	868,251	5,307,670	329,505
2030	458,780	(62,391)	100,740	420,431	329,505	73,958	403,463	823,894	86,153	910,048	36,220	873,828	5,488,646	329,505
2031	466,160	(63,965)	90,282	439,843	329,505	76,295	405,800	845,643	84,260	929,904	34,578	895,326	5,659,327	329,505
2032	481,126	(64,245)	107,572	437,799	329,505	77,340	406,845	844,645	90,401	935,045	33,503	901,542	5,817,525	329,505
2033	490,077	(65,274)	105,922	449,429	329,505	79,098	408,603	858,033	91,616	949,649	30,403	919,246	5,966,001	329,505
2034	505,881	(66,550)	110,406	462,026	329,505	81,196	410,701	872,727	93,487	966,214	29,729	936,485	6,105,232	329,505
2035	510,307	(68,281)	88,388	490,200	329,505	83,574	413,079	903,279	89,332	992,612	28,846	963,766	6,237,124	329,505
2036	517,169	(69,566)	91,529	495,206	329,505	85,288	414,793	909,999	91,621	1,001,621	27,533	974,087	6,359,827	329,505
2037	537,371	(69,805)	108,398	498,777	329,505	86,808	416,313	915,091	97,733	1,012,823	25,273	987,550	6,474,332	329,505
2038	537,764	(71,680)	91,444	518,001	329,505	88,678	418,183	936,184	95,679	1,031,864	23,599	1,008,264	6,581,942	329,505
2039	555,311	(72,337)	102,787	524,861	329,505	90,594	420,099	944,960	100,227	1,045,187	22,055	1,023,132	6,682,454	329,505
2040	559,206	(74,016)	89,573	543,649	329,505	93,001	422,506	966,155	98,401	1,064,556	22,538	1,042,017	6,776,680	329,505
2011 Net Present Value														
Period of 2011-2040	3,702,106	(541,504)	461,127	3,782,483	1,927,380	408,199	2,335,579	6,118,062	731,589	6,849,651	72,971	6,776,680		
Base Case O&M 2011-2040							611,421			611,421	0	611,421		
Utility Cost Present Value 2011-2040							2,947,000			7,461,072	72,971	7,388,101		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(34)	1,973
2017	(18)	1,477
2018	(26)	1,263
2019	(30)	1,502
2020	(34)	1,704
2021	(35)	1,855
2022	(47)	2,024
2023	(53)	2,175
2024	(63)	2,307
2025	326	2,419
2026	313	2,510
2027	300	2,545
2028	289	2,591
2029	279	2,611
2030	267	2,605
2031	253	2,625
2032	244	2,645
2033	219	2,665
2034	213	2,685
2035	205	2,706
2036	194	2,726
2037	177	2,747
2038	164	2,768
2039	152	2,789
2040	154	2,810

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized NGCC Replacement FT_CSAPR Early Carbon Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,400	7,010	0.34
2013	7,446	6,696	5,317	0.29
2014	4,238	6,936	5,561	0.34
2015	9,351	7,370	3,865	0.28
2016	4,097	4,204	1,638	0.01
2017	4,430	4,081	1,818	0.01
2018	4,358	4,290	1,798	0.01
2019	3,557	4,072	1,510	0.01
2020	4,573	4,394	770	0.00
2021	4,372	4,368	767	0.00
2022	4,559	4,367	766	0.00
2023	4,269	4,048	697	0.00
2024	3,655	4,118	712	0.00
2025	4,559	4,826	810	0.00
2026	3,917	4,770	786	0.00
2027	4,558	4,868	816	0.00
2028	3,884	4,765	784	0.00
2029	4,401	4,646	757	0.00
2030	4,332	4,831	801	0.00
2031	3,536	4,664	759	0.00
2032	4,572	4,940	822	0.00
2033	4,374	4,942	822	0.00
2034	4,558	4,979	826	0.00
2035	4,270	4,697	761	0.00
2036	3,658	4,756	775	0.00
2037	4,559	5,008	831	0.00
2038	3,917	4,840	795	0.00
2039	4,558	5,005	830	0.00
2040	3,886	4,851	795	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	75	2,165	2,089	6,900
2013	7,457	138	36	(102)	840	1,095	255	6,883
2014	7,469	139	17	(122)	752	1,361	608	6,894
2015	7,479	139	23	(116)	258	1,242	984	6,903
2016	7,488	139	19	(120)	585	405	(180)	6,911
2017	7,505	139	28	(111)	671	350	(321)	6,927
2018	7,536	139	37	(102)	542	383	(160)	6,955
2019	7,571	139	36	(103)	752	331	(422)	6,988
2020	7,604	139	34	(106)	521	431	(91)	7,019
2021	7,648	288	34	(254)	516	461	(55)	7,059
2022	7,695	288	34	(254)	530	419	(111)	7,102
2023	7,744	288	34	(254)	792	300	(492)	7,148
2024	7,798	289	34	(255)	759	302	(457)	7,198
2025	7,846	288	34	(254)	431	1,462	1,032	7,242
2026	7,896	288	34	(254)	339	1,448	1,109	7,288
2027	7,947	288	34	(254)	397	1,495	1,098	7,335
2028	7,999	289	34	(255)	381	1,391	1,009	7,383
2029	8,044	288	34	(254)	416	1,280	864	7,425
2030	8,093	288	34	(254)	424	1,365	941	7,470
2031	8,143	288	34	(254)	462	1,276	815	7,516
2032	8,195	289	34	(255)	429	1,417	988	7,564
2033	8,241	288	34	(254)	401	1,363	962	7,606
2034	8,289	288	34	(254)	353	1,369	1,016	7,651
2035	8,339	288	34	(254)	450	1,194	744	7,697
2036	8,389	289	34	(255)	440	1,193	753	7,743
2037	8,439	288	34	(254)	343	1,287	944	7,789
2038	8,488	288	34	(254)	408	1,133	725	7,835
2039	8,538	288	34	(254)	360	1,203	843	7,881
2040	8,589	289	34	(255)	423	1,097	674	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	1,277	1 -904 MW NGCC,	0	1,277	5.3%
2017	1,198	1,276		0	1,276	6.5%
2018	1,207	1,278		0	1,278	5.9%
2019	1,218	1,286		0	1,286	5.6%
2020	1,224	1,288		0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR Early Carbon Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Market Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)
2011	227,807	(12,788)	40,914	199,680	0	(0)	(0)	199,680	7,418	207,098	0	207,098	207,098	0
2012	255,302	(20,951)	94,814	181,439	0	(0)	(0)	181,439	87,229	268,668	0	268,668	454,399	0
2013	228,766	(29,661)	31,279	227,148	0	(0)	(0)	227,148	50,469	277,617	0	277,617	689,615	0
2014	273,936	(38,307)	56,211	256,032	607	0	607	256,639	102,971	359,609	1,379	358,230	968,993	607
2015	275,726	(50,969)	44,815	281,880	607	(0)	607	282,487	29,797	312,285	(17,667)	329,951	1,205,853	607
2016	71,170	(38,327)	(258,882)	368,380	36,583	0	36,583	404,963	1,596	406,559	(96,221)	502,780	1,538,075	36,583
2017	69,259	(38,798)	(318,409)	426,466	36,583	0	36,583	463,049	38,147	501,196	(70,844)	572,040	1,886,002	36,583
2018	76,389	(38,418)	(311,612)	426,420	36,583	0	36,583	463,003	41,531	504,534	(61,043)	565,577	2,202,640	36,583
2019	70,470	(38,237)	(332,289)	440,996	36,583	0	36,583	477,579	38,367	515,947	(72,956)	588,903	2,506,117	36,583
2020	300,686	(48,864)	(5,027)	354,576	238,249	44,830	283,079	637,657	68,871	706,528	(3,053)	709,581	2,842,702	238,249
2021	307,836	(62,937)	(3.122)	373,895	238.249	45,500	283,749	657,644	69,387	727,031	(3,364)	730,395	3,161,606	238,249
2022	314,699	(63,232)	(7.220)	385,151	238,249	46,377	284,626	669,778	70,228	740,006	(4,922)	744,927	3,460,989	238,249
2023	312,425	(63,221)	(32,571)	408,218	238,249	47,344	285,593	693,810	65,950	759,760	(6,021)	765,782	3,744,277	238,249
2024	319,471	(63,974)	(30,983)	414,429	238,249	48,305	286,554	700,983	67,945	768,928	(7,553)	776,482	4,008,678	238,249
2025	406,194	(57,945)	103,191	360,948	341,101	65,707	406,808	767,756	80,704	848,460	40,972	807,488	4,261,771	341,101
2026	422,838	(59,046)	105,942	375,942	341,101	68,371	409,472	785,414	80,818	866,231	40,824	825,407	4,499,905	341,101
2027	431,498	(59,683)	108,404	382,777	341,101	69,191	410,292	793,069	83,893	876,961	39,666	837,296	4,722,258	341,101
2028	442,087	(60,823)	103,199	399,711	341,101	71,307	412,408	812,119	82,824	894,943	38,934	856,010	4,931,502	341,101
2029	452,060	(62,288)	92,469	421,880	341,101	72,983	414,084	835,964	81,792	917,756	37,909	879,847	5,129,468	341,101
2030	458,780	(62,391)	100,740	420,431	341,101	73,958	415,059	835,490	86,153	921,644	36,220	885,424	5,312,846	341,101
2031	466,160	(63,965)	90,282	439,843	341,101	76,295	417,396	857,239	84,260	941,500	34,578	906,922	5,485,738	341,101
2032	481,126	(64,245)	107,572	437,799	341,101	77,340	418,441	856,241	90,401	946,641	33,503	913,138	5,645,970	341,101
2033	490,077	(65,274)	105,922	449,429	341,101	79,098	420,199	869,629	91,616	961,245	30,403	930,842	5,796,320	341,101
2034	505,881	(66,550)	110,406	462,026	341,101	81,196	422,297	884,323	93,487	977,810	29,729	948,081	5,937,275	341,101
2035	510,307	(68,281)	88,388	490,200	341,101	83,574	424,675	914,875	89,332	1,004,208	28,846	975,362	6,070,753	341,101
2036	517,169	(69,566)	91,529	495,206	341,101	85,288	426,389	921,595	91,621	1,013,217	27,533	985,683	6,194,917	341,101
2037	537,371	(69,805)	108,398	498,777	341,101	86,808	427,909	926,687	97,733	1,024,419	25,273	999,146	6,310,767	341,101
2038	537,764	(71,680)	91,444	518,001	341,101	88,678	429,779	947,780	95,679	1,043,460	23,599	1,019,860	6,419,614	341,101
2039	555,311	(72,337)	102,787	524,861	341,101	90,594	431,695	956,556	100,227	1,056,783	22,055	1,034,728	6,521,265	341,101
2040	559,206	(74,016)	89,573	543,649	341,101	93,001	434,102	977,751	98,401	1,076,152	22,538	1,053,613	6,616,540	341,101
2011 Net Present Value														
Period of 2011-2040	3,220,462	(519,453)	(216,615)	3,956,530	1,556,036	313,579	1,869,615	5,826,146	690,226	6,516,372	(100,168)	6,616,540		
Base Case O&M 2011-2040							611,421			611,421	0	611,421		
Utility Cost Present Value 2011-2040							2,481,037			7,127,793	(100,168)	7,227,961		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(922)	1,477
2018	(930)	1,263
2019	(934)	1,502
2020	(34)	1,704
2021	(35)	1,855
2022	(47)	2,024
2023	(53)	2,175
2024	(63)	2,307
2025	326	2,419
2026	313	2,510
2027	300	2,545
2028	289	2,591
2029	279	2,611
2030	267	2,605
2031	253	2,625
2032	244	2,645
2033	219	2,665
2034	213	2,685
2035	205	2,706
2036	194	2,726
2037	177	2,747
2038	164	2,768
2039	152	2,789
2040	154	2,810

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2020 then BS2 Replacement CC Added FT_CSAPR Early Carbon Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,400	7,010	0.34
2013	7,446	6,696	5,317	0.29
2014	4,238	6,936	5,561	0.34
2015	9,351	7,370	3,885	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	4,394	770	0.00
2021	4,372	4,368	767	0.00
2022	4,559	4,367	766	0.00
2023	4,269	4,048	697	0.00
2024	3,655	4,118	712	0.00
2025	4,559	4,826	810	0.00
2026	3,917	4,770	786	0.00
2027	4,558	4,888	816	0.00
2028	3,884	4,765	784	0.00
2029	4,401	4,646	757	0.00
2030	4,332	4,831	801	0.00
2031	3,536	4,664	759	0.00
2032	4,572	4,940	822	0.00
2033	4,374	4,942	822	0.00
2034	4,558	4,979	826	0.00
2035	4,270	4,697	761	0.00
2036	3,658	4,756	775	0.00
2037	4,559	5,008	831	0.00
2038	3,917	4,840	795	0.00
2039	4,558	5,005	830	0.00
2040	3,886	4,851	795	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	*Contract* Purchases	*Contract* Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	75	2,165	2,089	6,900
2013	7,457	138	36	(102)	840	1,095	255	6,883
2014	7,469	139	17	(122)	752	1,361	608	6,894
2015	7,479	139	23	(116)	258	1,242	984	6,903
2016	7,488	139	19	(120)	4,632		(4,632)	6,911
2017	7,505	139	28	(111)	4,761		(4,761)	6,927
2018	7,536	139	37	(102)	4,562		(4,562)	6,955
2019	7,571	139	36	(103)	4,842		(4,842)	6,988
2020	7,604	139	34	(106)	521	431	(91)	7,019
2021	7,648	288	34	(254)	516	461	(55)	7,059
2022	7,695	288	34	(254)	530	419	(111)	7,102
2023	7,744	288	34	(254)	792	300	(492)	7,148
2024	7,798	289	34	(255)	759	302	(457)	7,198
2025	7,846	288	34	(254)	431	1,462	1,032	7,242
2026	7,896	288	34	(254)	339	1,448	1,109	7,288
2027	7,947	288	34	(254)	397	1,495	1,098	7,335
2028	7,999	289	34	(255)	381	1,391	1,009	7,383
2029	8,044	288	34	(254)	416	1,280	864	7,425
2030	8,093	288	34	(254)	424	1,365	941	7,470
2031	8,143	288	34	(254)	462	1,276	815	7,516
2032	8,195	289	34	(255)	429	1,417	988	7,564
2033	8,241	288	34	(254)	401	1,363	962	7,606
2034	8,289	288	34	(254)	353	1,369	1,016	7,651
2035	8,339	288	34	(254)	450	1,194	744	7,697
2036	8,389	289	34	(255)	440	1,193	753	7,743
2037	8,439	288	34	(254)	343	1,287	944	7,789
2038	8,488	288	34	(254)	408	1,133	725	7,835
2039	8,538	288	34	(254)	360	1,203	843	7,881
2040	8,589	289	34	(255)	423	1,097	674	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	1,288	1 -904 MW NGCC,	0	1,288	5.2%
2021	1,238	1,303		0	1,303	5.2%
2022	1,249	1,303		0	1,303	4.3%
2023	1,255	1,303		0	1,303	3.8%
2024	1,264	1,303		0	1,303	3.1%
2025	1,281	1,303	1- 407 MW CC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FT_CSAPR Early Carbon Commodity Pricing

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
	Fuel Cost	Contract Revenue	Market Revenue/(Cost)	Fuel & Transactions	Carrying Charges	Incremental O&M	Total	Total Cost	Market Value of Allowances Consumed	Grand Total	Value of ICAP	Grand Total	CPW	Capital Expenditures
Annual Costs	(A)	(B)	(C)	(D)=(A)-(B)-(C)	(E)	(F)	(G)=(E)+(F)	(H)=(D)+(G)	(I)	(J)=(H)+(I)	(K)	(L)=(J)-(K)	(M)	(N)
2011	227,807	(12,788)	40,914	199,680	0	(0)	(0)	199,680	7,418	207,098	0	207,098	207,098	0
2012	255,302	(20,951)	94,814	181,439	0	(0)	(0)	181,439	87,229	268,668	0	268,668	454,399	0
2013	228,766	(29,661)	31,279	227,148	0	(0)	(0)	227,148	50,469	277,617	0	277,617	689,615	0
2014	273,936	(38,307)	56,211	256,032	607	0	607	256,639	102,971	359,609	1,379	358,230	968,993	607
2015	275,726	(50,969)	44,815	281,880	607	(0)	607	282,487	29,797	312,285	(17,667)	329,951	1,205,853	607
2016	71,170	(38,327)	(258,882)	368,380	36,583	0	36,583	404,963	1,596	406,559	(96,221)	502,780	1,538,075	36,583
2017	69,259	(38,798)	(318,409)	426,466	36,583	0	36,583	463,049	38,147	501,196	(70,844)	572,040	1,886,002	36,583
2018	76,389	(38,418)	(311,612)	426,420	36,583	0	36,583	463,003	41,531	504,534	(61,043)	565,577	2,202,640	36,583
2019	70,470	(38,237)	(332,289)	440,996	36,583	0	36,583	477,579	38,367	515,947	(72,956)	588,903	2,506,117	36,583
2020	82,710	(40,719)	(314,556)	437,984	43,914	0	43,914	481,898	43,630	525,529	(83,168)	608,697	2,794,848	43,914
2021	83,079	(52,517)	(319,786)	455,382	43,914	0	43,914	499,296	44,079	543,376	(90,581)	633,956	3,071,645	43,914
2022	85,668	(52,969)	(330,331)	468,968	43,914	0	43,914	512,882	44,633	557,515	(100,078)	657,593	3,335,929	43,914
2023	78,054	(54,435)	(360,221)	492,710	43,914	0	43,914	536,624	39,899	576,523	(108,269)	684,792	3,589,256	43,914
2024	79,413	(55,285)	(365,629)	500,327	43,914	0	43,914	544,241	41,468	585,710	(116,004)	701,713	3,828,198	43,914
2025	406,194	(57,945)	103,191	360,948	356,636	65,707	422,343	783,291	80,704	863,995	40,972	823,023	4,086,160	356,636
2026	422,838	(59,046)	105,942	375,942	356,636	68,371	425,007	800,949	80,818	881,766	40,824	840,942	4,328,776	356,636
2027	431,498	(59,683)	108,404	382,777	356,636	69,191	425,827	808,604	83,893	892,496	39,666	852,831	4,555,254	356,636
2028	442,087	(60,823)	103,199	399,711	356,636	71,307	427,943	827,654	82,824	910,478	38,934	871,545	4,768,296	356,636
2029	452,060	(62,288)	92,469	421,880	356,636	72,983	429,619	851,499	81,792	933,291	37,909	895,382	4,969,757	356,636
2030	458,780	(62,391)	100,740	420,431	356,636	73,958	430,594	851,025	86,153	937,179	36,220	900,959	5,156,352	356,636
2031	466,160	(63,965)	90,282	439,843	356,636	76,295	432,931	872,774	84,260	957,035	34,578	922,457	5,332,205	356,636
2032	481,126	(64,245)	107,572	437,799	356,636	77,340	433,976	871,776	90,401	962,176	33,503	928,673	5,495,164	356,636
2033	490,077	(65,274)	105,922	449,429	356,636	79,098	435,734	885,164	91,616	976,780	30,403	946,377	5,648,023	356,636
2034	505,881	(66,550)	110,406	462,026	356,636	81,196	437,832	899,858	93,487	993,345	29,729	963,616	5,791,288	356,636
2035	510,307	(68,281)	88,388	490,200	356,636	83,574	440,210	930,410	89,332	1,019,743	28,846	990,897	5,926,892	356,636
2036	517,169	(69,566)	91,529	495,206	356,636	85,288	441,924	937,130	91,621	1,028,752	27,533	1,001,218	6,053,012	356,636
2037	537,371	(69,805)	108,398	498,777	356,636	86,808	443,444	942,222	97,733	1,039,954	25,273	1,014,681	6,170,664	356,636
2038	537,764	(71,680)	91,444	518,001	356,636	88,678	445,314	963,315	95,679	1,058,995	23,599	1,035,395	6,281,169	356,636
2039	555,311	(72,337)	102,787	524,861	356,636	90,594	447,230	972,091	100,227	1,072,318	22,055	1,050,263	6,384,346	356,636
2040	559,206	(74,016)	89,573	543,649	356,636	93,001	449,637	993,286	98,401	1,091,687	22,538	1,069,148	6,481,026	356,636
2011 Net Present Value														
Period of 2011-2040	2,758,442	(500,707)	(866,715)	4,125,864	1,207,804	219,847	1,427,651	5,553,515	638,264	6,191,779	(289,247)	6,481,026		
Base Case O&M 2011-2040							611,421			611,421	0	611,421		
Utility Cost Present Value 2011-2040							2,039,072			6,803,200	(289,247)	7,092,447		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	(225)	1,507
2016	(938)	1,973
2017	(922)	1,477
2018	(930)	1,263
2019	(934)	1,502
2020	(938)	1,704
2021	(939)	1,855
2022	(951)	2,024
2023	(957)	2,175
2024	(967)	2,307
2025	326	2,419
2026	313	2,510
2027	300	2,545
2028	289	2,591
2029	279	2,611
2030	267	2,605
2031	253	2,625
2032	244	2,645
2033	219	2,665
2034	213	2,685
2035	205	2,706
2036	194	2,726
2037	177	2,747
2038	164	2,768
2039	152	2,789
2040	154	2,810

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized Market Replacement to 2025 then BS2 Replacement CC Added FT_CSAPR Early Carbon Commodity Pricing

	SO2 Emissions ktons	CO2 Emissions ktons	NOX Emissions ktons	HG Emissions (Tons)
2011	10,452	7,387	6,171	0.29
2012	10,586	8,400	7,010	0.34
2013	7,446	6,696	5,317	0.29
2014	4,238	6,936	5,561	0.34
2015	9,351	7,370	3,885	0.28
2016	4,097	2,600	1,465	0.01
2017	4,430	2,470	1,644	0.01
2018	4,358	2,695	1,627	0.01
2019	3,557	2,470	1,337	0.01
2020	4,573	2,783	597	0.00
2021	4,372	2,775	595	0.00
2022	4,559	2,775	595	0.00
2023	4,269	2,449	525	0.00
2024	3,655	2,513	539	0.00
2025	4,559	4,826	810	0.00
2026	3,917	4,770	786	0.00
2027	4,558	4,888	816	0.00
2028	3,884	4,765	784	0.00
2029	4,401	4,646	757	0.00
2030	4,332	4,831	801	0.00
2031	3,536	4,664	759	0.00
2032	4,572	4,940	822	0.00
2033	4,374	4,942	822	0.00
2034	4,558	4,979	826	0.00
2035	4,270	4,697	761	0.00
2036	3,658	4,756	775	0.00
2037	4,559	5,008	831	0.00
2038	3,917	4,840	795	0.00
2039	4,558	5,005	830	0.00
2040	3,886	4,851	795	0.00

	Summary of Energy Purchases and Sales (Gwh)							Internal Requirement 0.923 GWh
	Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	
2011	7,432	58	115	57	369	1,247	878	6,860
2012	7,476	138	117	(22)	75	2,165	2,089	6,900
2013	7,457	138	36	(102)	840	1,095	255	6,883
2014	7,469	139	17	(122)	752	1,361	608	6,894
2015	7,479	139	23	(116)	258	1,242	984	6,903
2016	7,488	139	19	(120)	4,632		(4,632)	6,911
2017	7,505	139	28	(111)	4,761		(4,761)	6,927
2018	7,536	139	37	(102)	4,562		(4,562)	6,955
2019	7,571	139	36	(103)	4,842		(4,842)	6,988
2020	7,604	139	34	(106)	4,517		(4,517)	7,019
2021	7,648	288	34	(254)	4,450		(4,450)	7,059
2022	7,695	288	34	(254)	4,497		(4,497)	7,102
2023	7,744	288	34	(254)	4,890		(4,890)	7,148
2024	7,798	289	34	(255)	4,872		(4,672)	7,198
2025	7,846	288	34	(254)	431	1,462	1,032	7,242
2026	7,896	288	34	(254)	339	1,448	1,109	7,288
2027	7,947	288	34	(254)	397	1,495	1,098	7,335
2028	7,999	289	34	(255)	381	1,391	1,009	7,383
2029	8,044	288	34	(254)	416	1,280	864	7,425
2030	8,093	288	34	(254)	424	1,365	941	7,470
2031	8,143	288	34	(254)	462	1,276	815	7,516
2032	8,195	289	34	(255)	429	1,417	988	7,564
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2034	8,289	288	34	(254)	353	1,369	1,016	7,651
2035	8,339	288	34	(254)	450	1,194	744	7,697
2036	8,389	289	34	(255)	440	1,193	753	7,743
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2040	8,589	289	34	(255)	423	1,097	674	7,927

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,108		0	1,108	-10.2%
2016	1,213	373		0	373	-69.3%
2017	1,198	372		0	372	-69.0%
2018	1,207	374		0	374	-69.0%
2019	1,218	382		0	382	-68.7%
2020	1,224	384		0	384	-68.6%
2021	1,238	399		0	399	-67.8%
2022	1,249	399		0	399	-68.1%
2023	1,255	399		0	399	-68.2%
2024	1,264	399		0	399	-68.5%
2025	1,281	1,303	1- 407 MW CC,1 -904 MW NGCC,	407	1,710	33.5%
2026	1,293	1,303		407	1,710	32.2%
2027	1,305	1,303		407	1,710	31.0%
2028	1,315	1,303		407	1,710	30.0%
2029	1,324	1,303		407	1,710	29.1%
2030	1,335	1,303		407	1,710	28.1%
2031	1,348	1,303		407	1,710	26.8%
2032	1,357	1,303		407	1,710	26.0%
2033	1,372	1,295		407	1,702	24.0%
2034	1,378	1,295		407	1,702	23.5%
2035	1,389	1,299		407	1,706	22.8%
2036	1,399	1,299		407	1,706	21.9%
2037	1,415	1,299		407	1,706	20.5%
2038	1,427	1,299		407	1,706	19.5%
2039	1,438	1,299		407	1,706	18.6%
2040	1,436	1,299		407	1,706	18.8%

Kentucky Power Company

REQUEST

Refer to pages 11-12 of the Weaver Testimony, Table 1, specifically, Options #2 and #3.

a. Explain the extent to which Kentucky Power considered the purchase of the simple cycle combustion turbine ("SCCT") generating units near the Big Sandy station and whether any attempt was made to negotiate a purchase.

b. Explain whether converting the SCCTs to combined cycle units would be uneconomical relative to building new units.

c. Provide a table showing the prices of natural gas used in the Strategist model to determine the economic viability of Options #2 and #3 and an explanation of the sources of the gas price data.

d. Provide a demonstration of and explanation of how sensitive the analyses results are to variations in the price of natural gas.

RESPONSE

a. Please see the Company's response to AG 1-22.

b. Please see the Company's response to AG 1-23.

c. The source of Option #2 and #3's natural gas price is a combination of the AEP-Fundamental Analysis group's commodity pricing forecast and AEP-FEL's indicative estimates for the cost of gas delivered to the Big Sandy facility.

Delivered Fuel Price as used by Strategist Model

	FT-CASPR 'Base' Fleet $/mmBtu	FT-CASPR Higer Band $/mmBtu	FT-CASPR Lower Band $/mmBtu	FT-CASPR Early Carbon $/mmBtu	FT-CASPR No Carbon $/mmBtu
2016	$6.33	$7.30	$5.60	$6.33	$6.33
2017	$6.47	$7.59	$5.73	$6.76	$6.47
2018	$6.66	$7.81	$5.89	$6.94	$6.66
2019	$6.80	$7.98	$6.01	$7.07	$6.80
2020	$6.86	$8.05	$6.07	$7.13	$6.86
2021	$7.11	$8.34	$6.29	$7.43	$6.96
2022	$7.43	$8.72	$6.57	$7.58	$7.04
2023	$7.63	$8.95	$6.75	$7.72	$7.22
2024	$7.88	$9.25	$6.97	$7.88	$7.46
2025	$8.13	$9.54	$7.18	$8.13	$7.69
2026	$8.23	$9.66	$7.28	$8.23	$7.79
2027	$8.42	$9.89	$7.45	$8.42	$7.98
2028	$8.60	$10.19	$7.60	$8.60	$8.15
2029	$8.79	$10.49	$7.77	$8.79	$8.33
2030	$8.91	$10.90	$7.87	$8.91	$8.43
2031	$9.03	$11.31	$7.98	$9.03	$8.54
2032	$9.15	$11.75	$8.09	$9.15	$8.65
2033	$9.28	$12.21	$8.19	$9.28	$8.77
2034	$9.41	$12.69	$8.31	$9.41	$8.89
2035	$9.55	$13.20	$8.44	$9.55	$9.01
2036	$9.69	$13.72	$8.56	$9.69	$9.14
2037	$9.83	$14.26	$8.68	$9.83	$9.27
2038	$9.98	$14.82	$8.81	$9.98	$9.40
2039	$10.12	$15.41	$8.94	$10.12	$9.53
2040	$10.27	$16.02	$9.07	$10.27	$9.67

d. A demonstration of how sensitive Option #2 and #3 are to variations in natural gas price can be found in Exhibit SCW-4. This Exhibit summarizes the cost of Option #2 and #3 over Option #1(Big Sandy 2 emission retrofit), under 5 discrete commodity pricing scenarios, all containing their own correlated assumptions for natural gas price. These results indicate that Option #2 is $177M (under LOW Band) to $437M (under HIGH Band) more expensive over the study period versus Option #1, depending on the selected commodity price scenario. Option #3 is shown to be $183M (under LOW Band) to $458M (under HIGh Band) more expensive over the study period versus Option #1, again, depending on the selected commodity price scenario.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 11 -1 2 of the Weaver Testimony, Table 1, at Option #4.

a. Explain why only five and ten year power purchase options were modeled.

b. Explain whether Kentucky Power issued a Request For Quote ("RFQ") to purchase market power.

c. If the answer is yes to part b. of this Item, provide a summary of the bids that were received and Kentucky Power's analysis of the bids leading to either acceptance or rejection.

d. If the answer to part b. of this Item is no, explain.

RESPONSE

a. As explained in Mr. Weaver's Direct Testimony beginning on page 25, line 13, t through page 26, it is critical to emphasize that the "purchase options" performed under Option #4A (5-Year) and Option #4B (10-Year) were reflective of an assumption that the "market" was, in fact, the PJM Reliability Pricing Model (RPM) market construct, *not* a traditional (e.g., bi-lateral) transaction that may encompass longer terms.

Rather, the rationale for those two options was to offer a valuation basis that ould allow the RPM construct to effectively "bridge" KPCo between any retirement dispositions for Big Sandy 1&2 that was undertaken (in 2015) until, ultimately, a combined cycle new- build solution would occur. (Whereas, conversely, Option #2 and Option #3 would seek to replace the Big Sandy units contemporaneously with their EGU MACT (aka "MATS")-required retirement dates). Essentially these 5 and 10 year "RPM-reliance" periods were merely variations of a "delayed-CC build" approach --under the notion that this Commission would ultimately desire such a regional/local "metal-in-the-ground" solution-- and were not intended to, again, be reflective of a bi- lateral transaction term. Page 38 starting at line 8, through page 40, line 10 of Mr. Weaver's testimony offers further rationale for a more limited time period-dependence on that available PJM-RPM construct.

Finally, each of these modeling runs do already reflect some, albeit limited, reliance on a PJM-RPM capacity (as well as PJM energy market) construct for a portion of KPCo's supply portfolio in any event. As suggested beginning on page 52, line 1 through page 53, line 18, under each of these modeled "options", KPCo would continue to be capacity-short. Therefore, a potential outcome could be reliance on the PJM-RPM construct --which was modeled-- or, potentially, *other* market options (see pg. 53, lines 6-9) for that smaller capacity need/tranche. Therefore, given this ~300-MW of market exposure tied to the non-replacement of Big Sandy Unit1, the notion of KPCo being completely exposed to PJM-RPM market pricing vagaries (via the non-replacement of both Big Sandy 1 and 2) was deemed not palatable for a period, for modeling purposes under Option #4, beyond 5 or, at most, 10 years.

b. No such RFQ solicitations have been issued.

c. N/A

d. As discussed in Mr. Weaver's testimony beginning on page 40, line 19, through page 42, line 3, the Company believes Option #2 served as a reasonable proxy for a non-PJM RPM (i.e., "bi-lateral) market option. For instance, based on discussion with AEP commercial experts, it is reasonable to assume that any long-term (minimum, 10-20 year term) competitive purchase power agreement (PPA) solicitation —for not only replacement capacity but for the largely "baseload" energy also being replaced— would be effectively offered/priced at the cost of a new-build combined cycle in response to such a solicitation.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 11-12 of the Weaver Testimony, Table 1. It discusses four options available to Kentucky Power to address unit disposition decisions facing the Big Sandy units. In several of the options there is a statement "with incrementally required capacity and energy needs purchased for calendar year 2015-and prospectively-from the PJM market." Provide a response and a complete explanation of the following:

a. If Kentucky Power remained in the AEP Pool, would that change its analysis or conclusions about building a scrubber at the Big Sandy Unit 2?

b. If Kentucky Power was in another pooling arrangement similar to the Corporate Separation analysis performed earlier this decade, explain whether that would have changed Kentucky Power's analysis or conclusions about building a scrubber at the Big Sandy Unit 2.

c. Given that Kentucky Power's customers have been supporting (the average cost along with an investment rate of 16.44 percent) OPCo's generating facilities, including the environmental facilities, through the FERC-approved Pool Agreement, should the FERC rule that some amount of the OPCo generation remain with Kentucky Power, explain whether this would have changed Kentucky Power's analysis or conclusion about building a scrubber at Big Sandy Unit 2.

RESPONSE

a. No. Please see Mr. Weaver's testimony beginning on page 49, line 7 through page 50, line 5.

b. No such analysis was performed. Although the "...Corporate Separation analysis performed earlier this decade" was an energy-only Pool; i.e., there was not a capacity element to that proposed Pool framework, meaning KPCo would have been required to (self-)build or acquire capacity in any event, in lieu of retaining the available capacity of Big Sandy Units 1&2 via the environmental retrofitting of those units.

c. No.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 12-14 of the Weaver Testimony.

a. Explain when Kentucky Power became aware of the necessity to curtail the Big Sandy units for an interim period to comply with the CSAPR SO2 "Phase 1" requirements.

b. Identify all other AEP affiliate generating units that will have to be curtailed on an interim basis to comply with either CSAPR or the MACT requirements.

c. Explain whether Kentucky Power intends to curtail operations at the Big Sandy plant during the 2012-2016 timeframe.

d. Explain the rationale for the decision to curtail the Big Sandy units in lieu of other AEP units. If the answer is related to either AEP or PJM system reliability, provide the power and transmission studies (including a narrative explanation of the study results) that support the decision.

e. When the Big Sandy units are curtailed, explain how Kentucky Power expects the power to be replaced and at what assumed cost.

f. Since Kentucky Power knew that SO2 mitigation would be required as a result of the 2007 Consent Decree, explain why it did not commence the process of satisfying those requirements sooner.

g. If a wet FGD had been installed at Big Sandy as soon as possible following the 2007 Consent Decree, explain what additional mitigation efforts, if any, would now be required to satisfy CSAPR, MACT, CCR, and other EPA requirements.

RESPONSE

a. Kentucky Power first became aware of the necessity to curtail the Big Sandy units for an interim period to comply with the CSAPR SO2 Phase I requirements when the final rule was issued by the EPA on July 6, 2011.

b. In general, all of AEP's coal-fired units that do not have post-combustion controls for SO2 or NOx (i.e. an FGD or an SCR) would require an operating restriction under CSAPR when compared to the units' historic operation given the current allowance allocations. The restriction is driven by SO2 allocations for some states and for NOx allocations for others. The final particulate emissions limit under the Mercury Air Toxics Standards (MATS) rule could require curtailment of operation at some units until existing particulate controls could be upgraded or additional particulate controls could be installed. AEP currently operates over 50 coal fired units, and less than ½ currently have both SO2 and NOx post-combustion controls. See attachment KPSC Staff Set 1-52 Attachment 1 for a list of AEP plants that currently have FGD and/or SCR equipment. The remaining AEP plants would potentially require curtailment on an interim period to comply with either CSAPR or MATS requirements.

c. Once the CSAPR rule becomes effective, and given the current allowance allocations, Kentucky Power will need to curtail operations at the Big Sandy Plant unless sufficient SO2 allowances are available from the market to cover the differences, and assuming the cost of allowances can be justified. This scenario will be necessary each year until the Big Sandy Unit 2 scrubber is placed in-service.

d. The priority of curtailing units is based on several factors. Reliability needs for the grid and cost of unit operation are the two main factors. AEP has the responsibility to its customers and shareholders to provide the lowest cost product; units that have a lower cost of operation will typically be utilized more than those with a higher cost of operation.

e. Under the current AEP Interconnection ("Pool") Agreement mechanism, any curtailed KPCo generation from the Big Sandy Station would be displaced initially with Primary Energy purchases from affiliate Pool Member Companies. No proforma determination of incremental costs/benefits associated with such curtailments has been modeled.

f. The Company was in the process of planning for the installation of an SO2 mitigation system in order to satisfy the requirements of the 2007 Consent Decree; however, the Company chose to re-evaluate its environmental compliance strategy as a result of the economic downturn, the remand of the Clean Air Interstate Rule (CAIR), and uncertainty over new environmental regulations from the EPA.

g. If a wet FGD had been installed at Unit 2, it could not have been completed by 2012, so Big Sandy would have faced the same potential curtailment if CSAPR had not been stayed. It is not possible to determine if additional controls would be needed for the MATS rule without the ability to determine actual emissions with the wet FGD to compare to the MATS limits. Given that the CCR rule and other EPA regulatory programs are still in development, it is not possible to determine if additional mitigation measures would be needed for these programs.

WITNESS: Scott C Weaver and John M McManus

Kentucky Power Company

REQUEST

Refer to page 13 of the Weaver Testimony, lines 4-13. It discusses the anticipated necessary timeframe to obtain Commission approvals, permit, engineer, and procure materials and components. Provide the following:

a. Explain when Kentucky Power or AEP became aware that, for continued operations of the Big Sandy units, a scrubber would need to be installed.

b. If the Big Sandy Unit 2 scrubber was operational before January 2012, explain whether the unit's generation would need to be constrained or curtailed.

c. Explain what increased/decreased costs for energy and capacity Kentucky Power expects to incur during the constrained or curtailed operational period.

d. Explain how these costs are recovered or how the credits would be flowed back to the ratepayers.

e. In order for the Big Sandy Unit 2 scrubber to have been operational on or before January 2012, when would it have been necessary to begin Phase 1 of the construction?

RESPONSE

a. The Company first became aware that, for continued operations of the Big Sandy units, a scrubber would need to be installed on Unit 1 when the final Mercury and Air Toxics Standards (MATS) rule was issued by the USEPA during mid-December 2011, and for Unit 2 when the 2007 Consent Decree was issued by the courts.

b. The Company would not expect any constraints or curtailments had an FGD been operational on Big Sandy Unit 2 prior to January 2012.

c. See the response to Staff 1-52, part e.

d. The specific energy and capacity costs received from the pool during any outage, constrained or curtailed period is not flowed through the ECR. The O&M costs related to approved projects from surplus operating company units are used to develop a weighted average capacity rate that is multiplied against the Company's capacity deficit as calculated on ES FORM 3.14, page 2 of 11 of the Company's monthly ECR filing that provides for the capacity costs to be recovered.

e. Using the historic durations for similar projects and the current Big sandy Unit 2 project schedule duration of 56 months, Phase I would have needed to commence in the second quarter of 2006.

WITNESS: Ranie K Wohnhas

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
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Kentucky Power Company

REQUEST

Refer to page 14 of the Weaver Testimony, lines 1-9. It states, "[a]s indicated above, it is anticipated that the necessary time to obtain Commission approvals, permit, engineer, procure materials and components, construct and commission a DFGD retrofit would place the in-service date, for economic modeling purposes, at approximately June 1, 2016. Given that, and the limiting factors associated with the EGU ["Electric Generating Unit"] MACT rule and the NSR Consent Decree, it was then assumed that, for modeling purpose, Big Sandy Unit 2 would be removed from service effective January 1, 2016 for the period leading up to the beginning of the normal retrofit "tie-in" outage which would occur in approximately the April/ May 2016 timeframe."

a. Based on AEP's prior scrubber installation experience, provide, by generating unit, the average length of time the units were down for "tie-in".

b. Explain whether these units with scrubber installation were also down three months prior to the "tie-in" timeframe.

RESPONSE

a. See Attachment 1 to this response for the actual FGD tie-in outages dates.

b. These units were not down for three months prior to the tie-in outage.

WITNESS: Robert L Walton

	Start	End	Notes
Amos 1	9/11/2010	1/16/2011	
Amos 2	10/19/2009	2/26/2010	
Amos 3	9/5/2008	3/12/2009	Duration was driven by ESP rebuild and not FGD
Mountaineer 1	9/9/2006	2/16/2007	
Mitchell 1	1/20/2007	4/28/2007	
Mitchell 2	9/23/2006	1/15/2007	
Cardinal 1	2/2/2008	3/26/2008	
Conesville 4	2/21/2009	6/3/2009	
Cardinal 2	9/8/2007	12/10/2007	
Cardinal 3	In Progress	N/A	

Kentucky Power Company

REQUEST

Refer to page 14 of the Weaver Testimony, lines 5-8, and Exhibit SCW-1.

a. For PJM members participating in the Reliability Pricing Model ("RPM") and electing to meet their capacity resource obligations through the Fixed Resource Requirement ("FRR") construct and then are unable to meet their capacity obligations through their own generation assets, explain whether the members are prohibited from meeting capacity obligations by purchasing that capacity through bilateral or other contractual means outside PJM or with a PJM member directly. In other words, if a company elects FRR and cannot meet its obligations, is it required to fulfill its obligations through PJM and to use Locational Marginal Pricing ("LMP") as the pricing mechanism?

b. Explain whether there are any transmission constraints preventing Kentucky Power from obtaining power to help meet both its capacity and energy requirements from outside PJM and, if so, identify those constraints.

RESPONSE

a. An FRR Load Serving Entity (LSE) in this situation has several options available to them:

1) Procure additional FRR capacity from another FRR LSE in the form of a bilateral/contractual agreement.

2) Procure RPM capacity that was not offered (if approved by PJM) or offered but did not clear in the RPM auction(s) from an RPM LSE in the form of a bilateral/contractual agreement.

3) Procure external non-PJM capacity from an outside entity in the form of a bilateral/contractual agreement, subject to meeting any firm power import restrictions into PJM.

In the event the LSE cannot procure sufficient additional capacity so as to meet their unforced capacity obligation, the LSE will be assessed an FRR Commitment Insufficiency Charge for the shortage in meeting the Percentage of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for the remainder of the minimum term of the FRR election.

In addition, the LSE will be required to switch to RPM for the Delivery Year for which the capacity is insufficient and the subsequent Delivery Years.

b. PJM determines the capacity and energy requirements for the AEP Zone (Kentucky Power is part of the AEP Zone). If capacity and energy requirements are to be met from outside PJM, any constraints are identified and remedial actions undertaken by PJM to address them. At present -- and not knowing the specific import/flow source-- the Company is not aware of such transmission constraints that have been identified by PJM.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to the Weaver Testimony, page 14, line 17, to page 15, line 4. It discusses the retrofit of dry FGD and SCR technology at the Rockport Generating Station ("Rockport") for modeling purposes.

a. Explain when a commitment for a course of action at Rockport will be made.

b. Explain how the dates used in the baseline modeling affect the modeling results. For example, if the installation dates are accelerated or delayed by two years, provide the results of the base line modeling.

c. Explain whether the Rockport units are required to be constrained or curtailed until the dry FGDs and SCRs are placed in service.

RESPONSE

a. I&M is endeavoring to make a decision on which of the two Rockport units to install the environmental projects sometime in 2012.

b. A Strategist analysis was performed on the single Rockport unit currently proposed to be retrofitted with an FGD and SCR that examined the impact of delaying that retrofit completion by 2 years (from 1/2016, until 1/2018). From an affiliate I&M perspective --which utilizes 85% of the capacity and energy from the unit, compared to KPCo's 15%-- those relative economics suggested an incremental cumulative present worth (CPW) of study period (2011-2040) "Generation" revenue requirements would be increased by at least $185 million by such a delay. This can be rationalized by virtue of the fact that the incremental energy value from a fully-controlled Rockport unit versus one that could be required to be significantly curtailed --due to CSAPR-- during that 2-year interim period, more than offset the incremental 'fixed' costs associated with the earlier retrofit date.

c. Yes. As best summarized in the Excel spreadsheet on page 2 of this response, the level of CSAPR unit annual allowance allocations for Rockport Units 1&2 represents just a fraction of the recent (average: 2006-2010) annual Rockport unit emissions of both SO2 and NOx. For instance, for, particularly, SO2, beginning in the 2014 "Phase 2" period of CSAPR, Rockport 1&2 annual allowance allocations represent only about 38% of those units' historical annual emissions of SO2.

WITNESS: Scott C Weaver

FINAL CSAPR Unit Allocation Levels

Plant Name	Unit	SO2 Allocation 2012 (tons)	SO2 Allocation 2014 (tons)	NOx Annual Allocation 2012 (tons)	NOx Annual Allocation 2014 (tons)	NOx OS Allocation 2012 (tons)	NOx OS Allocation 2014 (tons)
Rockport	1	21,292	11,776	7,883	7,788	3,316	3,265
Rockport	2	19,923	11,019	7,376	7,288	3,148	3,100

Historical Emissions

		2006	2007	2008	2009	2010	5-Yr Avg.	2012 Alloc as % of 5-yr Hist Avg	2014 Alloc as % of 5-yr Hist Avg
SO2 Tons									
Rockport	1	41,313	22,827	31,295	30,139	28,722	30,859	69.0%	38.2%
Rockport	2	42,230	25,830	28,794	24,657	25,520	29,406	67.8%	37.5%
Total		83,543	48,657	60,089	54,796	54,242	60,265	68.4%	37.8%
NOx (Annual) Tons									
Rockport	1	13,985	8,789	12,019	10,906	10,804	11,301	69.8%	68.9%
Rockport	2	14,139	10,427	10,940	8,856	9,741	10,820	68.2%	67.4%
Total		28,124	19,216	22,959	19,762	20,545	22,121	69.0%	68.2%

Note: Represents total Rockport Unit (i.e., I&M and AEG Ownership shares)

Kentucky Power Company

REQUEST

Refer to page 14 of the Weaver Testimony, lines 17-23.

a. Thoroughly describe the "Rockport units' unique NSR Consent Decree requirements."

b. Explain whether the statement means that Kentucky Power is only responsible for expenses associated with the January 1, 2016 dry FGD retrofit and not the "more aggressive" January 1, 2014 retrofit with the SCR installed by year end 2019.

c. For each Rockport unit, provide a breakout of what retrofit expenses will be either allocated to Kentucky Power or paid by Kentucky Power through capacity and energy purchases, through the long term purchase contract only, and the timing of any such payments.

d. Explain how Kentucky Power plans to replace 15 percent of the power and capacity it obtains from the Rockport units when the long term purchase contract expires in 2022.

RESPONSE

a. Under the NSR Consent Decree, Rockport Unit 1 is required to install both FGD and SCR technology by December 31, 2017; while Rockport Unit 2 is required to install both FGD and SCR technology by December 31, 2019.

b. Kentucky Power is responsible for all cost associated with it's 30% purchase entitlement from AEP Generating Company's (50%) ownership share, or a combined approximate 390 MW share of the Rockport Unit 1 and Unit 2 facilities.

c. See the response to part b.

d. The Company has not determined a formal disposition strategy for the Rockport purchase entitilement as of the agreement's termination date. That said, for modeling purposes in this Big Sandy disposition evaluation, it was assumed the Rockport purchase agreement would continue in its current form through the full (2040) study period.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 15 of the Weaver Testimony, lines 7-18. It discusses the initial economic evaluations performed from the perspective of a "stand-alone" Kentucky Power.

a. Explain whether there were assumed capacity and energy costs or credits flowing to/from affiliate AEP operating companies via the Pool Agreement. How would the results and/or conclusions of the economic study change if capacity and energy costs or credits were flowing to/from affiliate AEP operating companies via the Pool Agreement.

b. Explain whether AEP or Kentucky Power have made any previous filings with Commission indicating that the current AEP Pool would be terminated.

c. If the answer to part b. of this Item is yes, explain when AEP or Kentucky Power plans on requesting the termination of the AEP Pool at FERC and this Commission.

RESPONSE

a. There were no capacity and/or energy costs or credits flowing from/to AEP operating companies via the Pool Agreement assumed in this analysis as such analyses were performed on a 'stand-alone' basis under the assumption the current Pool would be terminated. Therefore, while the prospects around the Pool remain uncertain, as indicated on Mr. Weaver's testimony beginning on page 49, line 7, through page 50, line 22, the ultimate disposition economics and driving decision would not change.

b. No.

c. N/A

WITNESS: Scott C Weaver and John M McManus

Kentucky Power Company

REQUEST

Refer to page 15 of the Weaver Testimony and Exhibit SCW-1.

a. Explain whether Kentucky Power is contemplating forming another pool 'agreement with any other AEP affiliates. If yes, provide the anticipated timing of any such agreements, the AEP affiliates, the specific benefits of such an agreement to Kentucky Power and its ratepayers, and how such an agreement will affect the modeling results presented in the Application.

b. If another pool agreement is formed, identify the environmental compliance costs incurred by its AEP affiliates, if any, that will likely be borne by Kentucky Power ratepayers.

c. If another pool agreement is formed, explain the validity of assuming, in the Application, for modeling purposes, that Kentucky Power is a standalone company.

d. Describe the benefits specific to Kentucky Power and to each of the other AEP affiliate companies that may be included in a new pool agreement.

RESPONSE

a. As indicated in the Company's response to KPSC 1-2a, a new agreement is currently under development with an expected filing at FERC by the end of the first quarter 2012. The new agreement will be among Kentucky Power Company, Appalachian Power Company (APCo) and Indiana & Michigan Power Company (I&M).

b. It has not yet be determined what, if any, environmental compliance costs incurred by APCo and/or I&M (excluding KPC's portion of Rockport) would be passed through to KPC ratepayers. As stated in my testimony, page 13, lines 5-6, the Company does recognize its obligation to come before the commission to amend its Environmental Compliance Plan to reflect any changes to the pool agreement.

c. The future power cost sharing agreement currently being contemplated by Kentucky Power and others obligates each operating company that is a party to the agreement to maintain adequate long-term supplies of capacity and energy and is intended more for contingency purposes.

d. As the agreement is currently contemplated, it will provide the following possible benefits to KPCo and the other potential operating company participants: (a) unit outage coordination, (b) risk mitigation, (c) flexibility in choosing the best PJM capacity market alternative as applicable conditions dictate, (d) recognition of the load diversity between the operating companies, including KPCo, (e) compatibility with the PJM markets and (f) enablement of optimization and trading on behalf all of the Operating Companies including KPCo.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 18 of the Weaver Testimony, line 5. It discusses using a proxy for an estimated Kentucky Power weighted average cost-of-capital. Describe the estimated Kentucky Power weighted average cost-of-capital used in the economic analysis.

RESPONSE

The Excel spreadsheet found on page 2 of this response offers the implicit rate of return (weighted average cost of capital) utilized in the economic analysis.

WITNESS: Scott C Weaver

Kentucky Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2010

	Investment Life (Years)		
	15	20	30
Return (WACC) (1)	**8.58**	**8.58**	**8.58**
Depreciation (2)	4.51	3.01	1.67
FIT (3) (4)	1.70	1.77	1.40
Property Taxes, General & Admin Expenses	1.78	1.78	1.78
	16.57	15.14	13.43

(1) Based on a 100% (as of 12/31/2010) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 35% Federal Income Tax Rate

Kentucky Power Company

REQUEST

Refer to page 21 of the Weaver Testimony, lines 1-5. It discusses a critical input parameter that includes the installed costs of the environmental retrofits. Explain the results of the economic analysis and conclusion if the installed costs of the required environmental retrofits come in at 10 to 20 percent above what is currently reflected in this filing.

RESPONSE

While that specific calculation has not been performed, based on the cost sensitivity assessment that has been done, the economic analysis would continue to favor Option #1 (Big Sandy 2 Retrofit) even if the retrofit installed cost were to increase by 20 percent above what is currently reflected in the filing.

Please refer to Mr. Weaver's testimony on page 44, beginning on line 1 through line 14. Economic "break-even" points were determined that would establish the level of required increase in the cost of the Big Sandy 2 retrofit vis-a-vis both the Replacement CC-Build alternative (Option #2) and well as the Big Sandy 1 CC Repowering alternative (Option #3). It indicates that --under FT-CSAPR or "Base" pricing-- the retrofit installed cost would have to increase by 23.8% and 25.4%, respectively, before an point of economic indifference was achieved.

Even assuming "LOWER Band pricing" --which would likely favor a 'gas-solution'-- were employed, that economic break-even would require the Big Sandy 2 retrofit installed cost to increase by 17.8% before the overall study period economics would be on-par with that Option #2.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 22 of the Weaver Testimony. Explain the anticipated delivered price differences for coal with varying sulfur contents and the effects FGD technology selection has on the modeling results for Option #1.

RESPONSE

The FGD technology screening process basically assumed three types of SO2 emitting coal. Various scrubber technologies were evaluated assuming 1.7 lb/MMBtu (SO2 emitting), blended 3.0 lb/MMBtu, and blended 4.5 lb/MMBtu coal products. Compared to the 4.5 lb coal, the delivered prices for the 1.7 lb coal averaged 30% to 35% higher through 2040. However, as described in the direct testimony of Company witness Ranie Wohnhas beginning on page 9, line 20, through page 10, line 9, the 1.7 lb/MMBtu Central Appalachian (CAPP) coal product potentially faced issues of availability and price variability. The 3.0 lb/MMBtu coal delivered price was 25% to 30% higher on average than the 4.5 lb/MMBtu coal through 2040. As shown in Exhibit SCW-3, the ranking of the "NID" Dry FGD technology that would utilize a 4.5 lb./MMBtu product was superior to the Wet or Dry designs from a relative 10 year IRR standpoint. The selection of the top ranked NID 4.5 lb/MMBtu option allowed the lowest cost retrofit option to be compared to the Big Sandy 2 retirement and replacement alternatives.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 23-24 of the Weaver Testimony.

a. Explain why a specific combined cycle ("CC") design including duct firing and chillers was assumed in the analyses for Options #2 and #3.

b. Explain why a specific size unit was assumed in each analysis and identify any economies of scale based on unit size.

c. Since Options #2 and #3 also assumed indicative cost estimates and performance parameters associated with gas pipeline infrastructure and pressuring and metering equipment to receive gas, explain why the option of using the nearby existing simple cycle facility was not considered. Given the lack of existing CC generating facilities, it would seem that this site possesses the necessary infrastructure to support new or converted gas turbines.

RESPONSE

a. Duct firing and chillers were included as a means to maximize plant capacity and peaking capability.

b. Cost estimates were developed for 2x2x1 configuration utilizing Mitsubishi G-Frame gas turbines to more closely match the current capacity of Big Sandy Unit 2. The same configuration was estimated utilizing a GE F-frame size gas turbine similar to AEP's other combined cycle plants. The economy of scale resulted in an approximate 155 MW net (unfired) output increase and $175/kW cost reduction in favor of the G-frame configuration.

c. Please see the Company's response and attachments to AG 1-22 and AG 1-23.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 24 of the Weaver Testimony, Table 2.

a. Provide a detailed explanation and break out of costs referenced in columns (c) and (e) for each row of the chart.

b. Confirm the dollar amounts in columns (d) and (g) are total cost installed and not the dollar amount per kW installed.

c. If not provided above, provide a detailed explanation of what additional costs are included in Modeling CCR-related.

d. If not provided above, provide a detailed explanation of what additional owner‘s costs are allocated from OPCo, why the allocation varies between Options #1 through #3, and why they must be accepted.

RESPONSE

a. See the spreadsheet on page 2 of this response for the supporting detail that supports each of the line-item cost estimates in that TABLE 2.

b. The values reflected in columns (d) and (g) do represent the cost estimates on a "(2011) Dollars per kW Installed " and are detailed under the response to part a.

c. The CCR-related costs reflected on TABLE 2 represent those additional major environmental regulation costs (i.e, over-and-above the DFGD) that were incorporated into the Strategist modeling for Big Sandy.

d. Assuming the term "OPCo" means KPCo-affiliate Ohio Power Company, there are no such allocated costs reflected in these estimates. Rather, these indirect cost estimates reflect typical corporate overhead charges, not included as part of the "EPC" estimate that would be expected to be assigned to Kentucky Power Company generation-related capital work orders. The capital work order overhead rate applicable to the 'Big Sandy 2 Retrofit' projects of 9.1%, was provided by AEP Engineering Projects & Field Services (EP&FS) and represents Company and AEPSC costs inclusive of various construction overheads, clearings and billings that are typically charged to such generation-related capital work orders. The rate utilized for both the 'New-Build CC' and 'Big Sandy 1 CC Repowering', and also provided by AEP EP&FS, was at their instruction reduced to an estimate of only 7.0% in recognition that the base (EPC-direct) cost estimate for those specific CC projects did include some level of owner's costs that would typically be included in the indirect generation capital work order overhead rate.

WITNESS: Scott C Weaver

TABLE 2

Estimated "Alternative" Capital Expenditures

Utilized in Strategist Modeling
(TOTAL Project Costs, Excluding AFUDC)

Source:
"Cost Detail" tab... cell 'X'

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)			EPC Cost		Add'l Owner's Cost/OH Alloc	TOTAL COST *(Excluding AFUDC)*	
(2)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(3)	Option #1: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(4)	RETROFIT Option						
(5)	Dry (NID™) FGD		$769 K:11	869 Q:30	$70 K:12	$839 K:14	948 Q:14
(6)	*Plus: Add'l Costs included in Modeling*			(a)			(a)
(7)	*CCR-Related (thru 2017)*		*$44* K:22	*48* Q:36	*$4* *(= 44 x .091)*	*$48* *(= 44 + 4)*	*53* *(= 48 x 48 / 44)*
(8)	*TOTAL All Projects*	*800*	*$814* *(= 769+44)*	*917* *(= 869+48)*	*$74* *(= 70+4)*	*$888* *(= 839+48)*	*1,001* *(= 948+44)*

Note: totals may not foot due to rounding

(a) CCR-related (2011$ cost/kW)
corrected from filed version of TABLE 2
(however, est. *dollar values* unchanged)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(9)		*Unit Capacity*					
(10)		*(w/ Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(11)	Option #2: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(12)	REPLACEMENT Option						
(13)	New-Build CC *(@ BS site)*	*904*	$1,066 K:45	1,092 Q:50	$75 K:46	$1,141 K:48	1,169 Q:52

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(14)		*Unit Capacity*					
(15)		*(w/ Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(16)	Option #3: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(17)	REPLACEMENT Option						
(18)	BS1 CC Repowering	*780*	$994 K:62	1,180 Q:67	$70 K:63	$1,063 K:65	1,263 Q:69

DFGD and Alternative Project Cost Estimates

	2011	2012	2013	2014	2015	2016	2017	2018	TOTAL	Cost per kW Nominal ('As-Spent')$	Cost per kW 2011 $
Nominal k$											
Big Sandy 2 DFGD Retrofit											
BS000LDFL BS U0 FGD Landfill	2,280	3,347	7,853	17,014	21,495	10,568	143	0	62,700	$ 94	$ 86
BS001ASSC BS U2 FGD Assoc	0	4,000	12,000	18,000	36,000	102,100	0	0	172,100	$ 258	$ 229
BS001FGD0 Big Sandy U2 FGD	0	20,000	62,000	102,000	142,000	80,300	0	0	406,300	$ 609	$ 554
Total FGD Direct Costs	2,280	27,347	81,853	137,014	199,495	192,968	143	0	641,100	$ 962	$ 869
Contingency Adder @ 20% (Per EP&FS)	456	5,469	16,371	27,403	39,899	38,594	29	0	128,220		
Total FGD Direct -- Contingency-Adj.	2,736	32,816	98,224	164,417	239,394	231,562	172	0	769,320		
AEP Allocated Costs/OH (9.1%)	249	2,986	8,938	14,962	21,785	21,072	16	0	70,008		
GRAND TOTAL FGD	2,985	35,803	107,162	179,379	261,179	252,634	187	0	839,328		$ 948
CCR (only)											
000020353 BS U2 Bottom Ash Reline				0	889	4,121	4245		9,255		
000020356 BS U2 Ash WWT System			0	1,747	8,735	17,471	6,988	0	34,941		
TOTAL CCR Direct	0	0	0	1,747	9,624	21,592	11,233	0	44,196		

	2011	2012	2013	2014	2015	2016	2017	2018	TOTAL	Cost per kW 2011$
2011 k$	(Escalation Factor)		2.8%							
TOTAL Unit (Contingency-Adjusted)										
Big Sandy 2 DFGD Retrofit										
BS000LDFL BS U0 FGD Landfill	*2,736*	*3,907*	*8,917*	*18,794*	*23,097*	*11,046*	*145*	*0*	68,642	
BS001ASSC BS U2 FGD Assoc	*0*	*4,669*	*13,626*	*19,883*	*38,682*	*106,719*	*0*	*0*	183,579	
BS001FGD0 Big Sandy U2 FGD	*0*	*23,346*	*70,402*	*112,668*	*152,580*	*83,933*	*0*	*0*	442,930	
Total FGD Direct Costs	*2,736*	*31,923*	*92,946*	*151,345*	*214,359*	*201,698*	*145*	*0*	*695,151*	*$ 869*
CCR (only)										
000020353 BS U2 Bottom Ash Conversion	-	-	-	-	*796*	*3,590*	*3,597*	-	7,982	
000020356 BS U2 Ash WWT System	-	-	-	*1,608*	*7,822*	*15,218*	*5,921*	-	30,568	
TOTAL CCR Direct	*0*	*0*	*0*	*1,608*	*8,618*	*18,807*	*9,518*	*0*	*38,551*	*$ 48*

New-Build CC (Brownfield @ BS site)										Cost per kW	
Cash Flow	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*			*100.0%*	Nominal ('As-Spent')$	'2011 $'/kW
Assuming 2x1 Mitsubishi 501-GAC											
Contingency-Adjusted											
Nominal k$											
Project Estimate (Per S&L/Kiewet Study)	4,845	53,295	290,700	445,740	145,350	29,070	0	0	969,000		
Contingency Adder @ 10% (Per EP&FS)	485	5,330	29,070	44,574	14,535	2,907	0	0	96,900		
Total EPC	5,330	58,625	319,770	490,314	159,885	31,977	0	0	1,065,900	$ 1,179	
AEP Allocated Costs/OH (Increm 7.0%)	373	4,104	22,384	34,322	11,192	2,238	0	0	74,613	$ 83	
GRAND CC @ BS	5,703	62,728	342,154	524,636	171,077	34,215	0	0	1,140,513		
Total '2011 $' EPC	*5,330*	*57,028*	*302,588*	*451,331*	*143,164*	*27,853*	*0*	*0*	*987,293*		*$ 1,092*
Total '2011 $' OH	*373*	*3,992*	*21,181*	*31,593*	*10,022*	*1,950*	*0*	*0*	*69,111*		
Total '2011 $' TOTAL	*5,703*	*61,020*	*323,769*	*482,924*	*153,186*	*29,803*	*0*	*0*	*1,056,404*		*1,169*

(Big Sandy Unit 1) Repowered CC										Cost per kW	
Cash Flow	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*			*100.0%*	Nominal ('As-Spent')$	'2011 $'/kW
Assuming 2x1 Mitsubishi 501-GAC											
Contingency-Adjusted											
Nominal k$											
Project Estimate (Per S&L/Kiewet Study)	4,141	45,546	248,430	380,926	124,215	24,843	0	0	828,100		
Contingency Adder @ 20% (Per EP&FS)	828	9,109	49,686	76,185	24,843	4,969	0	0	165,620		
Total EPC	4,969	54,655	298,116	457,111	149,058	29,812	0	0	993,720	$ 1,274	
AEP Allocated Costs/OH (Increm 7.0%)	348	3,826	20,868	31,998	10,434	2,087	0	0	69,560	$ 89	
GRAND CC @ BS	5,316	58,480	318,984	489,109	159,492	31,898	0	0	1,063,280		
Total '2011 $' EPC	*4,969*	*53,166*	*282,097*	*420,768*	*133,470*	*25,967*	*0*	*0*	*920,436*		*$ 1,180*
Total '2011 $' OH	*348*	*3,722*	*19,747*	*29,454*	*9,343*	*1,818*	*0*	*0*	*64,431*		
Total '2011 $' TOTAL	*5,316*	*56,888*	*301,844*	*450,222*	*142,813*	*27,785*	*0*	*0*	*984,867*		*1,263*

Kentucky Power Company

REQUEST

Refer to pages 25-26 of the Weaver Testimony, regarding the discussion of Option #4, the "(Full) Capacity Replacement Purchase."

a. Explain whether a RFQ solicitation for capacity and energy was not also issued as an additional alternative to full reliance on the PJM market capacity and energy and pricing.

b. Explain the rationale for only considering full market participation in PJM for the purchase of power.

c. If a RFQ solicitation was issued, provide the analysis of the bids including the terms of the bids and why each bid received was not acceptable.

d. If a RFQ solicitation was not issued seeking capacity and energy, explain the rationale for not seeking such a solicitation.

RESPONSE

a. For the reasons set out in the testimony of Mr. Weaver beginning on page 40, line 11, through page 42, line 3, an RFQ solicitation was not issued. In summary, based on input from AEP commercial experts with experience around such long-term (10-20 year) contractual arrangements, Option #2 (a Big Sandy 2 Replacement CC alternative) represented the alternative in which KPCo management believed would serve as a proxy for such a market solicitation for capacity beginning in that (2016) timeframe. Another critical factor established by KPCo management was the going-in desire that any long-term solution should maintain a generation presence in eastern Kentucky. "Market" Options #4A and #B (PJM-RPM market capacity & energy for 5 and 10 years, respectively... followed then by New-Build CCs in 2020 and 2025), were viewed as short-term or, effectively, "bridge" solutions until a long-term--preferably Kentucky-domiciled-- generation solution could be established.

b. See the response to part a. of this question.

c. No market solicitation was issued.

d. See the response to part a. of this question.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 27 of the Weaver Testimony.

a. Since AEP and Kentucky Power are stand-alone generators for their own customers within the PJM system, explain the relevance of the LMP clearing prices for gas fired combined cycle combustion turbines ("CCCTs") and where those units settle in the PJM dispatch stack

b. Under either Option #2 or #3, explain how the cost of generation and transmission is determined and passed on to Kentucky Power retail customers.

RESPONSE

a. Although the KPCo system and its generators were considered to be "stand-alone" in the Strategist modeling, the KPCo system was allowed to interact with the PJM energy market when it was economic to do so. As stated in Mr. Weaver's testimony, the natural gas units (e.g. CCCTs) often serve as the marginal, or "price setting" units in the PJM energy market. Likewise, the modeled dispatch cost of the CCCTs was used to determine if such KPCo generation (e.g. under "Options #2 and #3") would be economically merited to be selected in the proxied PJM energy market.

b. It would be determined by the costs on the Company's books and recovered through its base rates.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 28-30 of the Weaver Testimony.

a. For each of the Options #1 through #4, provide the results of evaluating each of the long term commodity pricing views on each Option.

b. Provide a detailed explanation of how the economic costs associated with Option #1 change relative to Options #2 through #4 once a carbon tax becomes effective.

RESPONSE

a. In addition to the results summarized on Exhibit SCW-4 and Exhibits SCW-4A through 4E, please see the response to Staff 1-48 which, for each Option, offers detailed Strategist-modeled results across each of the respective long-term commodity price views discussed on pages 28-30.

b. At a high level, the relative CO2 emission rates for a gas alternative are approximately one-half of those of a coal alternative. Therefore, on a $/ton-emitted basis, the variable CO2 emission costs for (CC) gas-fired generation would be approximately one-half of a coal alternative. However, it is important to realize that the respective long-term commodity pricing views were holistically-determined; meaning any impact of, for instance, an assumed carbon tax would have correlated impacts on other long-term commodity prices, including coals, natural gas, energy, etc.

In fact, by comparing the Exhibit SCW-4 relative results under the "(Base) Fleet Transition-CSAPR" pricing view (also provided in more detail --by 'Option'-- under Exhibit SCW-4A) versus the "Fleet Transition-No Carbon" view (also provided in more detail --by Option-- under Exhibit SCW-4D), one can see the overall impact on the relative study period KPCo CPW of generation costs between any of the Options modeled.

WITNESS: Scott C Weaver

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order dated January 13, 2012
Item No. 68
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to pages 30-40 of the Weaver Testimony and Exhibit SCW-1, Figure 1-1, page 13 of 14, and Exhibit SCW-4.

a. Explain how the AEP Fundamental Analysis group derived and/or obtained PJM forward capacity and energy prices for Options #2 through #4.

b. Explain why only power purchases through PJM using PJM mechanisms were modeled.

c. If other power purchase options were considered, including but not limited to purchases from the gas fired generating station residing near the Big Sandy station, provide a description of those options.

d. Identify and describe the PJM LMP area in which Kentucky Power is modeled to participate and describe all factors that are setting prices, including but not limited to seasonality, load centers, unit location and availability to meet load, and reliability requirements.

e. Within PJM, generally and specifically the LMP area within which Kentucky Power participates, explain whether and how LMP set prices are affected and modeled by the timing of generation units either being curtailed permanently or curtailed temporarily during a retrofit from 2012 to 2020.

f. For each of the Options modeled, explain whether Kentucky Power being in another power pool would or would not affect the results and, if so, explain how the results would be affected.

RESPONSE

a. The AEP Fundamental Analysis group uses proprietary modeling software to forecast capacity and energy prices. The software, called AURORA^{xmp}, developed by EPIS, Inc. is a production costing dispatch model which outputs the prices based on a variety of inputs. The inputs include information describing generating units, some of which comes from Ventyx as well as fuel price forecasts developed by Fundamental

Analysis, economic forecasts developed by AEP's Economic Analysis group using Moody's dot com information, and an AEP consensus view of environmental issues.

The energy prices used in the Monte Carlo simulations that are graphically represented in Exhibit SCW-1, Figure 1-1, of Mr. Weaver's testimony have the forecasted "Fleet Transition-CSAPR" prices as the 'base', or starting price for all of the cases evaluated. Each risk iteration can have a slightly elevated or depressed price depending on the randomized risk factors selected by the model. The endogenous Monte Carlo modeling capabilities of the AURORA^{xmp} system uses a Latin Hypercube risk factor selection method in order to produce the best distribution of risk variability in the smallest number of iterations.

b. For shorter-term energy purchases it is reasonable to assume KPCo, as a PJM-RTO member/load serving entity, would be modeled to acquire its needed resources from the available transparent markets within that RTO so as to avail itself of the attendant reliability and reasonable price certainty offered. For example, such 'short-term' energy needs could literally be for daily energy balancing purposes.

For the purposes of the Monte Carlo modeling, the power purchases were set up as coming from a generic, non-specific source having the forecasted power prices as a starting point for the risk iteration variability.

See also the response to Staff 1-65, part a.

c. No other power purchase options were considered.

d. Kentucky Power units are modeled to be dispatched against a "generic" market supply based on a PJM/AEP Generating Hub energy price forecast --developed by AEP Fundamental Analysis as explained in the response to part a of this question-- which, in turn, is part of an overall-modelled U.S. Eastern Interconnect system.

e. As available, typically lower-(variable) dispatch cost coal-fired generation decreases over time in response to required unit curtailments or derates, energy prices will naturally increase.

f. An analysis of the options with Kentucky Power being in another power pool was not performed and any assumption as to how the results would change would be purely speculative.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 31-34 of the Weaver Testimony, where it discusses the retirement and replacement of Big Sandy Unit 2 with a new CC facility (Option #2) and the retirement and replacement of Big Sandy Unit 2 with the repowering of Big Sandy Unit 1 as a CC facility (Option #3) have higher Cumulative Present Worth costs ("G" Revenue Requirements).

a. Provide the date the economic analysis was completed that supported these conclusions.

b. Describe all the circumstances or inputs that have changed between when the economic nalysis or studies were performed that supported the plan to retire both Big Sandy units and rebuild one as a 640 megawatt natural gas plant and today's plan to retrofit Big Sandy Unit 2 with a dry FGD.

RESPONSE

a. The Strategist profiles were performed over the late-September through October 2011 timeframe; however, the final set of price scenario-specific evaluations that served to create Exhibit SCW-4 were completed in approximately late-October 2011.

b. See the response to Staff 1-85 for an explanation of the changes in the installed cost estimates used in the Strategist modeling for Option #3. In addition, the earlier analysis that supported the retirement of both Big Sandy units and repowering one unit as a CC was performed under commodity price forecasts that assumed CO2 pricing would begin in 2017 at $18.73/ton and escalates to $28.45/ton by 2040. The timing and level of CO2 pricing used in the earlier analysis helps to favor the CC replacement option compared to the current analysis that delays CO2 pricing to 2022 at $15/ton escalating to $19/ton.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 36 of the Weaver Testimony, lines 12-17. It states, "such advance recovery (from 20 years to 15 years) of these environmental investments would neither add significant costs to the Base/"Option #1" Big Sandy Unit 2 retrofit economics in absolute terms nor-as previously reviewed-would it cause the relative economics with either of the replacement-build alternatives (Option #2 or #3) to be significantly influenced." Explain whether the same conclusion would hold true under a delay recovery (from 20 years to 30 years) of these environmental investments.

RESPONSE

Yes, the same conclusion would be true. The difference in the present value stream of the $940M Big Sandy 2 Retrofit --with AFUDC-- fixed (carrying) costs between a 20-year recovery period (assuming a 15.14% annual carrying charge rate) and a 30-year recovery period (assuming a 13.43% annual carrying charge rate), both discounted at 8.58%, would have only an approximate $5.6M impact on relative study cycle CPW of generation costs, or a value that is approximately only one-tenth of one percent (0.1%) of the overall study period CPW result of $6,839 million (per Exhibit SCW-4A and the companion detail offered in response to Item No. 48 of the Staff's First Set).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 39-40 of the Weaver testimony.

a. Explain whether long term capacity and energy purchases are allowed or even possible within PJM and, if so, how such purchases are accomplished and priced.

b. Explain how both the projected price of capacity and the price of energy under PJM's RPM are determined and used in the model.

c. In the PJM LMP area in which Kentucky Power would participate, describe how much capacity and energy is available that is in excess of what is needed to satisfy load and set the marginal price.

RESPONSE

a. Long-term capacity and energy transactions are allowed within PJM. The method and pricing of individual transactions will vary based on the parties involved. The only requirement for generation resources is that they must offer their capacity into the RPM auction(s) unless:

1) The generation resources are part of an FRR portfolio whether by ownership or by a bilateral/contractual agreement.

2) The generation resources will be unavailable during the delivery year and PJM has approved their absence in advance.

3) The generation resource is otherwise engaged in a bilateral/contractual agreement.

b. The PJM market capacity and energy price is developed by AEP's Fundamental Analysis group employing the Aurora^{XMP} model for each of the 5 commodity price scenarios used in the economic evaluation of Big Sandy unit disposition alternatives. The price of market (proxied as PJM-RPM) capacity is used to determine a cost of capacity purchases when KPCo needs capacity and doesn't build resources (e.g. Options #4A and #4B) to meet its PJM reliability requirements. In addition, the same market capacity price is used to determine capacity revenue when KPCo has excess capacity to sell into the PJM capacity market. The PJM market-proxied (i.e., 'AEP Gen Hub') energy prices established in the Aurora^{XMP} tool are scaled to develop an hourly profile and then applied in the Strategist cost optimization model in a 'typical-week' hourly format (i.e.,168 hour) for each month. The hourly energy prices are compared to KPCo generation's marginal energy cost to determine if KPCo is an exporter/seller of energy, or importer/purchases, to/from the PJM energy market.

c. PJM determines the capacity and energy requirements for the AEP Zone (Kentucky Power is part of the AEP Zone). The RTO service area capacity and energy levels are neither surplus nor deficient. In the event an RTO service area has capacity or energy needs, the remaining members of the RTO will fulfill that need on a real-time basis.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 40-42 of the Weaver Testimony, specifically the discussion focusing on natural gas combined cycle units.

a. Explain whether the discussion means that Kentucky Power did not attempt to either solicit any long term power (sourced from natural gas combined cycle units or otherwise) from any source under any conditions or to purchase gas generating assets and only assumed that the cost of purchased power would be equal to the cost of a new combined cycle unit.

b. Explain why the discussion focuses on CCCTs only, and not other alternative types of fuel or technology.

c. If not already addressed above, explain specifically why the option of purchasing the natural gas combustion turbines located near the Big Sandy station and either converting them to a combined cycle units or adding a combined cycle unit to the existing facility are not viable options.

d. If not addressed above, since Kentucky Power is short on peaking capacity, explain whether its potential partners in a new power pool have excess peaking capacity that would benefit Kentucky Power.

RESPONSE

a. See the responses to KPSC 1-50, parts b and d, and KPSC 1-65, part a.

b. KPCo would require baseload capacity to replace the baseload Big Sandy coal facility. New coal and new nuclear could not be constructed in the time frame required. A combustion turbine facility would only provide peaking capacity, not economic baseload energy. Therefore a combined cycle facility was the logical choice.

c. Please see the Company's response to AG 1-22 and AG 1-23.

d. Please see the Company's response to Staff 1-59c. KPCo operates within the PJM RTO "pool", which does have peaking capacity.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to the Weaver Testimony, Exhibit SCW-1, page 4. Was a range, or ranges, of projected peak demands and internal loads over the forecast period used in the utility disposition models using Strategist? If not, explain. If a range or ranges of peak demand and internal load were utilized, provide them.

RESPONSE

A range of forecasted peak demands and internal loads was not used in the Strategist analysis. (However, as shown in Exhibit SCW-1, Table 1-5 of Mr. Weaver's testimony, changes in load (GWh) was one of the key risk factors varied in the Monte Carlo risk analysis profiled in the Aurora^{XMP} tool.)

The rationale for not incorporating a range of projected peak demand and internal loads over the forecast period in the Strategist tool was largely a function of the immateriality such an additional analysis would ultimately offer to the unit disposition modeling and decision itself. Specifically, given that the roughly 800 MW of generating capacity at issue that is represented by Big Sandy Unit 2 is over one-half of KPCo's resource portfolio (see Exhibit SCW-1, page 6), any "uncertainty" regarding the relative growth (or contraction) of KPCo peak demand load obligation --vis-a-vis the current long-term load forecast utilized in the evaluation-- would have no real bearing on this disposition decision. For instance, even if KPCo would experience zero internal peak demand growth between, say, 2011 and 2030, as opposed to the 157 MW of growth identified on Exhibit SCW-1, Table 1-1, it would have no real impact on the need for that facility (or a near-size alternative replacement). Likewise, if that internal peak demand growth estimate were to increase by as much as a two-fold magnitude versus the current forecast (i.e., by 314 MW) it would only suggest that perhaps KPCo would need to consider additional capacity resources (self-build or market purchases) but, in any event, this load variation would not impact the disposition decision-making process around, specifically, Big Sandy Unit 2.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to the Weaver Testimony, Exhibit SCW-2, page 2. What is the basis for the $15.08 per metric tonne estimate for $C0_2$ in the base case in 2022? What escalation factor was used for subsequent years and what is the basis for the escalation?

RESPONSE

The carbon dioxide price (CO_2) reflects a national carbon tax and reflects an industry consensus view. The price is escalated by the forecasted Consumer Price Index.

A consensus view represents the amalgamation of various sources of information. The long-term forecast is shaped by the views of many stakeholders, including, but not limited to:

Investment Community - Equity and Fixed Income analysts
Third-Party Consultants - IHS Cera, PIRA, Wood Mackenzie
Industry Groups - Edison Electric Institute
Government Agencies - EPA, DOE, NERC, FERC
Trade Press - Argus Air Daily, Coal Daily, Coal Weekly, The Energy Daily, Megawatt Daily, Gas Daily
Various Stakeholders - Independent System Operators, Interest Groups (Environmental and Industry)
Energy Companies - Listen to earnings calls, press releases, SEC filings, etc
Internal Information - Experience from other organizations within the company.
Independent Studies - Proprietary research studies

The company uses this information to develop and test the robustness of the long-term forecast. In the case of opposing views, we use the contrary position to better understand the reasons that support our view. At times, we have differing views from other stakeholders.

WITNESS: Scott C Weaver and Karl R. Bletzacker

Kentucky Power Company

REQUEST

Refer to Weaver Exhibit SCW-2, page 2. The capacity value for all scenarios increases from $27.73/MW-Day in 2013 to $126.00/MW-Day in 2014. Explain the increase in capacity value beginning in 2014. Describe how the capacity value was escalated through 2030 in the base case and each of the scenarios

RESPONSE

The increase in capacity price reflects actual auction results. Please refer to page four of the following link - http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

Capacity prices are fundamentally derived from the Aurora^{XMP} dispatch model. The price reflects the non-energy revenue requirement to ensure system reliability.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Provide in an electronic format the Strategist model input files used to generate the following exhibits. The response should include references to the source of the input data.

a. Exhibit SCW-4A;
b. Exhibit SCW-4B;
c. Exhibit SCW-4C;
d. Exhibit SCW-4D; and
e. Exhibit SCW-4E.

RESPONSE

The Company is unable to provide the requested input files. Strategist is a proprietary utility planning application that is licensed solely by Ventyx Inc., which owns Strategist in its entirety. Kentucky Power contacted Ventyx Inc. and it confirmed that the application software, source code, database, and associated documentation, including input files, are its confidential and proprietary intellectual property. Access to the documentation may be granted solely by Ventyx Inc., at its own discretion, under a mutually binding Non-Disclosure Agreement. Access to the database and/or the application itself is granted only under exclusive license with Ventyx Inc. Ventyx does not allow access to the Strategist source code under any circumstances. Kentucky Power will assist Commission staff in contacting Ventyx, Inc. to obtain the required Non-Disclosure Agreement.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

With the proposed retirement of Big Sandy Unit 1 in 2015, coupled with other anticipated unit retirements in the region, does Kentucky Power anticipate a shortfall in generation capacity?

RESPONSE

As noted in the response to Staff 1-44, the Company is currently evaluating alternatives to replacing the capacity from Big Sandy Unit 1 and does not anticipate a shortfall in generation capacity.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 7-8 of the Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony").

a. Does the discussion imply, under Option #1, that Kentucky Power would purchase all of the high sulfur coal to be burned at the Big Sandy units from Eastern Kentucky and, if not, from where would it purchase such high sulfur coal?

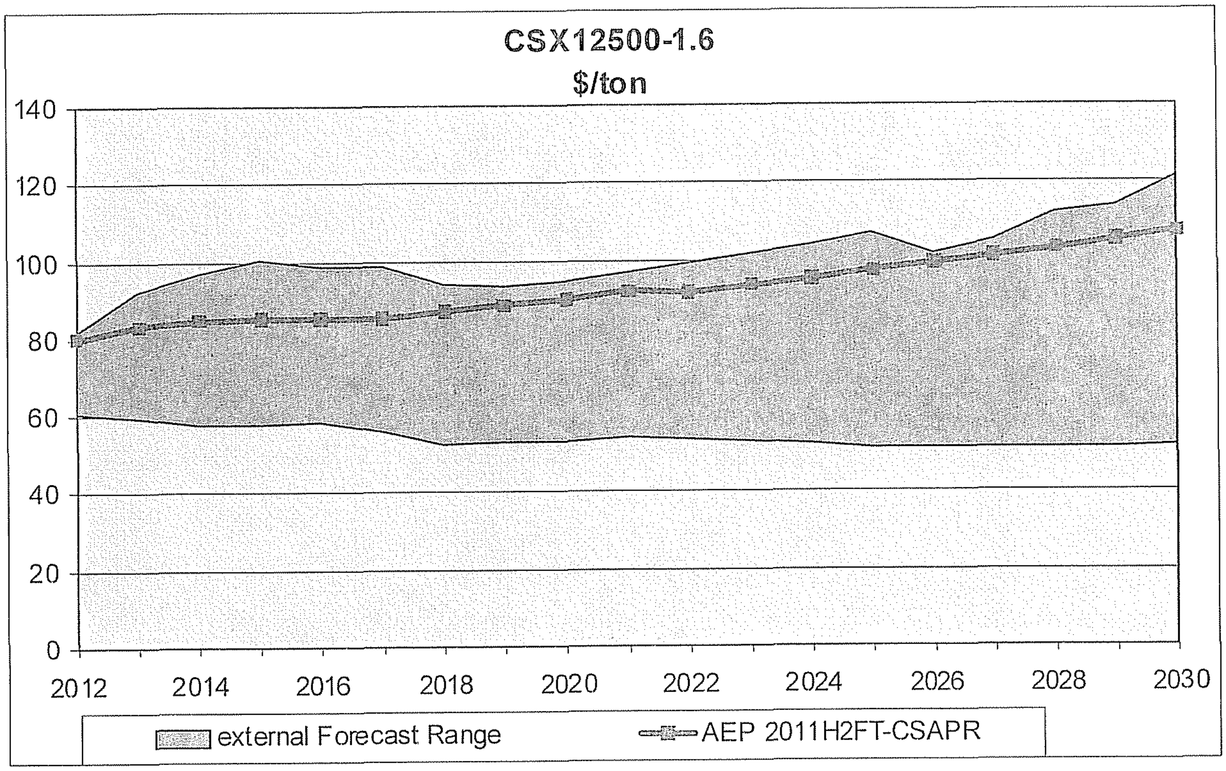
b. If not provided elsewhere, provide the projected coal purchase prices for the various sulfur contents, projected transportation costs, and delivered prices at the Big Sandy station used in the modeling exercises supporting Option #1

RESPONSE

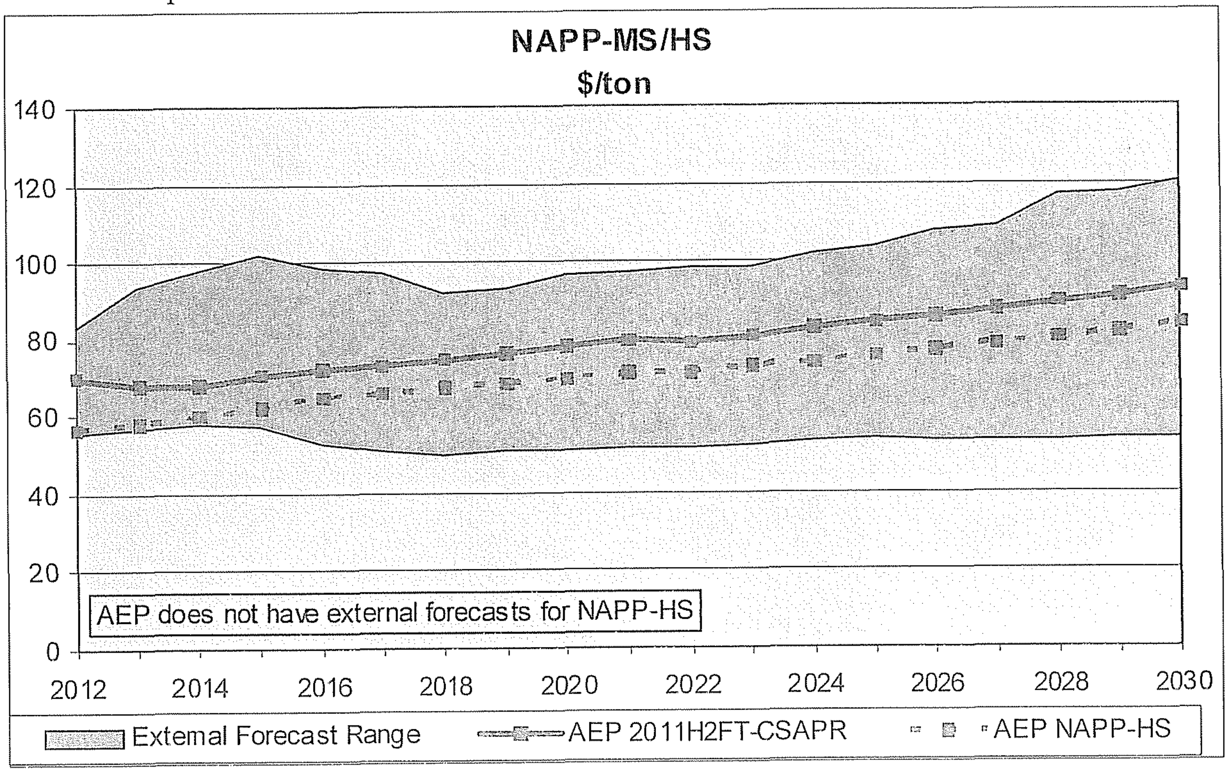
a. Eastern Kentucky would be a potential source for the high sulfur fuel to be burned at the Big Sandy Plant after the FGD retrofit is complete. But, as described on Page 10, lines 18-21, of my testimony, the high sulfur fuel could potentially come from the Illinois Basin (including western Kentucky) or from the Northern Appalachian region (including eastern Kentucky).

b. Forecast for NAPP and CAPP coal prices are based on cost of production and supply-demand relation. Also, research was conducted to compare the AEP forecast to external forecasts, as shown below.

Forecast comparison of CAPP CSX12500 Btu/lb, 1.6 lb-SO2/mmBtu



Forecast comparison of NAPP-MS



Transportation mode used for CAPP is rail, which includes rail rate, railcar cost, freezing treatment and fuel surcharge. Transportation mode for NAPP is barge-truck, which includes barge rate, transloading and truck rate. Estimate of transportation costs for CAPP and NAPP, as shown below, is based on currently existing contracts and negotiation of contract renewal for near term, and forecast for long-term.

Transportation cost

Mine District	CAPP-Big Sandy	CAPP-Kanawha	NAPP-Showmaker
Mode	Rail	Rail	Barge-Truck
2012	7.34	8.82	10.27
2013	7.63	9.19	10.53
2014	9.40	11.25	10.81
2015	9.70	11.61	11.10
2016	9.98	11.95	11.40
2017	10.27	12.30	11.70
2018	10.57	12.66	12.00
2019	10.88	13.03	12.32
2020	11.19	13.41	12.65
2021	11.46	13.74	12.98
2022	11.74	14.07	13.32
2023	12.02	14.41	13.68
2024	12.31	14.76	14.14
2025	12.61	15.13	14.42
2026	12.91	15.49	14.81
2027	13.22	15.87	15.22
2028	13.54	16.26	15.62
2029	13.86	16.66	16.05
2030	14.19	17.07	16.48

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, lines 7-11.

a. Explain whether Kentucky Power believes that a decision in this case should be based on any socioeconomic factors.

b. If the answer to part a. of this Item is yes, provide a list of the socioeconomic factors that Kentucky Power believes should be considered.

RESPONSE

a/b. The Company does not believe any specific socioeconomic factor should be used to make a decision in this case but rather as stated on page 9, line 2, of the Wohnhas testimony, they reinforce the DFGD alternative.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, line 14. Provide the calculations supporting the 86 jobs and the $6.0 million in annual compensation.

RESPONSE

The 86 jobs was an internal estimate of the net jobs that would be eliminated by replacing Big Sandy Unit 2 with a gas unit. This estimate was based upon AEP's experience on the number of employees needed to run and maintain a gas unit. Using an annual wage amount of $70,000 per eliminated position calculates to $6,020,000.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, line 16-17. Provide the calculations supporting the annual reductions in payroll and property taxes of $3.2 million and $461,000, respectively.

RESPONSE

The payroll taxes were actual taxes paid in 2010, and the property taxes were actual taxes paid in 2009.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, lines 18-19. Provide the source and calculations supporting the $75 per ton coal cost and the approximately $165 million per year injected into the local economy.

RESPONSE

The $75 per ton coal cost was an estimated average cost per ton of coal as was the 2.2 million tons of coal consumed to calculate the $165 million dollars per year. The Company did not break down the consumption by unit.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8 of the Wohnhas Testimony, lines 20-21. It states, "... with the indirect impact on mining and transportation (500 jobs, $8 million in severance taxes, and $25 million in wages per year) of the gas options."

a. Provide the calculations that support the 500 jobs, $8 million in severance taxes, and the $25 million in wages per year.

b. Explain whether Kentucky Power anticipates that all coal burned at Big Sandy Unit 2 after the dry FGD is installed will come from Kentucky sources.

RESPONSE

a. This information was provided by the "Committee to Save the Big Sandy Power Plant" which was sponsored by Energy Ventures Analysis, Inc. Please refer to page 2 of this response for the supporting document.

b. Currently all coal burned at Big Sandy Unit 2 does not come from Kentucky sources and the Company anticpates that after the dry FGD is installed it will continue to burn coal at Big Sandy Unit 2 from both Kentucky and non-Kentucky sources.

WITNESS: Ranie K Wohnhas

COMMITTEE TO SAVE THE BIG SANDY POWER PLANT

1. AEP Kentucky Power serves the East Kentucky coal fields. Most of the economic activity and jobs in AEP's service territory are related to coal mining and support services. Over one-third of the entire industrial load of Kentucky Power is coal mines.
2. Kentucky Power owns only one power plant, the 1,060 MW Big Sandy plant, located in Louisa, Kentucky, which provides most of the power to this service territory. The Big Sandy plant burns about 2.5 million tons per year of coal, almost all mined in East Kentucky (a little comes from West Virginia). In 2010, this plant spent $175 million on coal purchases.
3. New EPA regulations proposed in 2011 (Utility MACT and Cross-State Air Pollution Rule) will require AEP to invest in new emission controls (scrubbers) in order to keep burning coal at Big Sandy, or close the plant.
4. AEP has not yet decided whether to invest in keeping the Big Sandy plant open. Originally, AEP planned to build scrubbers at Big Sandy, but recently AEP has announced that the plant may be closed and replaced with a new natural gas plant, because of EPA's new regulations.
5. Whether AEP invests in Big Sandy or closes it and replaces it with gas, the ratepayers of Kentucky Power will be faced with a large rate increase to pay for compliance with the new EPA regulations. The coal mining community of East Kentucky believes that Kentucky Power should invest in the Big Sandy plant because the jobs and tax revenues from this plant support the entire area.
6. The coal produced to supply Big Sandy provides the local area over 500 direct mining jobs, severance taxes over $8 million per year, and wages over $25 million per year. In addition, the coal burned by Big Sandy supports jobs for suppliers and truckers, as well as taxes for the local schools and governments.
7. National environmental groups are intervening in Kentucky's rate cases to try to force utilities to close power plants burning Kentucky coal. The local community, who are Kentucky Power's largest ratepayers, support investing in Big Sandy and burning Kentucky coal. We need the support of the elected representatives of East Kentucky to save the Big Sandy power plant.

Kentucky Power Company

REQUEST

Refer to page 9 of the Wohnhas Testimony, lines 3-13.

a. If not provided elsewhere, provide the preliminary analysis which concluded that Big Sandy Units 1 and 2 would be retired with Big Sandy Unit 1 being repowered as a CCCT unit, including a listing and discussion of the reasonableness of all assumptions and any presentations made to management supporting the results of the analysis.

b. If not provided elsewhere, provide a detailed comparison of all assumptions made in the preliminary analysis and in the subsequent analysis supporting Option #1. Changes in primary assumption drivers should be highlighted and discussed specifically.

RESPONSE

a. Please refer to Attachment 1 of this response.

b. There was no specific detailed listing of assumptions. The various pages of Attachment 1 show where all of the information was obtained. Please refer to the Company's response to Staff 1-69 for the drivers that changed between the preliminary and subsequent analysis.

WITNESS: Ranie K Wohnhas

SUMMARY

Kentucky Power Co.

Big Sandy Generating Unit Disposition Analysis

Life-Cycle (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS> .... vs. Option #1-'*BASE*')

UNIT DISPOSITION ALTERNATIVES

KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	Retrofit (2015) [A] (D-FGD/CCR)	Retrofit (2015) (D-FGD/CCR)	Retire (2015) Repl w/Mkt to 2020, then CC	Retire (2015) Replace w/ ~800-MW CC	Retire (2015) Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	Retrofit (2015) (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario

$Millions

CO2 Sensitivity	*Jan '11 Forecast* [B]	Path "A" ("No CO2 Policy")		69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		(115)	30	(269)
BASE (ORIG)		Path "A"	195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")		(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")		(498)	(369)	(617)

% *(2016-2040)*

CO2 Sensitivity	*Jan '11 Forecast* [B]	Path "A" ("No CO2 Policy")		1.3%	1.5%	0.2%
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		-1.7%	0.4%	-3.9%
BASE (ORIG)		Path "A"	3.1%	-1.5%	0.4%	-2.2%
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")		-5.5%	-2.7%	-7.0%
LOW-Side Sensitivity		Path "A" ("Lower Band")		-8.0%	-5.9%	-9.9%

(Levelized) $/MWh *(2016-2040)*

CO2 Sensitivity	*Jan '11 Forecast* [B]	Path "A" ("No CO2 Policy")		1.4	1.7	0.2
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		(2.4)	0.6	(5.5)
BASE (ORIG)		Path "A"	0.40	(2.0)	0.5	(2.8)
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")		(7.1)	(3.5)	(9.1)
LOW-Side Sensitivity		Path "A" ("Lower Band")		(10.2)	(7.6)	(12.6)

(A) For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to10 Years; recovery period for CC options remain at 30 Years

(B) (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

(C) *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes

- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

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(COST / <SAVINGS> .... vs. Option #1-'*BASE*')

	UNIT DISPOSITION ALTERNATIVES				
KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	**Retrofit (2015)** [(A)] (D-FGD/CCR)	**Retrofit (2015)** (D-FGD/CCR)	**Retire (2015)** Repl w/Mkt to 2020, then CC	**Retire (2015)** Replace w/ ~800-MW CC	**Retire (2015)** Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	**Retrofit (2015)** (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario

			$Millions			
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")		69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		(115)	30	(269)
BASE (ORIG)		Path "A"	195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")		(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")		(498)	(369)	(617)

			% *(2016-2040)*			
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")		1.3%	1.5%	0.2%
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		-1.7%	0.4%	-3.9%
BASE (ORIG)		Path "A"	3.1%	-1.5%	0.4%	-2.2%
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")		-5.5%	-2.7%	-7.0%
LOW-Side Sensitivity		Path "A" ("Lower Band")		-8.0%	-5.9%	-9.9%

			(Levelized) $/MWh *(2016-2040)*			
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")		1.4	1.7	0.2
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)		(2.4)	0.6	(5.5)
BASE (ORIG)		Path "A"	0.40	(2.0)	0.5	(2.8)
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")		(7.1)	(3.5)	(9.1)
LOW-Side Sensitivity		Path "A" ("Lower Band")		(10.2)	(7.6)	(12.6)

[(A)] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to 10 Years; recovery period for CC options remain at 30 Years

[(B)] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

[(C)] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes

o "Retirement" options exclude costs associated w/ socio-economic impacts to the region

o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:

1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

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(COST / <SAVINGS> .... vs. Option #1-*'BASE'*)

	UNIT DISPOSITION ALTERNATIVES				
KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	**Retrofit (2015)** [(A)] (D-FGD/CCR)	**Retrofit (2015)** (D-FGD/CCR)	**Retire (2015)** Repl w/Mkt to 2020, then CC	**Retire (2015)** Replace w/ ~800-MW CC	**Retire (2015)** Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	**Retrofit (2015)** (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario			$Millions				
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	Path "A" ("No CO2 Policy")			69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)			(115)	30	(269)
BASE (ORIG)		Path "A"		195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [(C)]	Path "A" ("Fleet Transition")			(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")			(498)	(369)	(617)
SENSITIVITY... Impact of a 5-Year Delay in CO2 Tax							
BASE (ORIG)	*Jan '11 Forecast* [(B)]	**Path "A"**				46	(83)
BASE (REV)	*Mar '11 Forecast* [(C)]	**Path "A" ("Fleet Transition")**				(152)	(390)

[(A)] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to 10 Years; recovery period for CC options remain at 30 Years

[(B)] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

[(C)] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

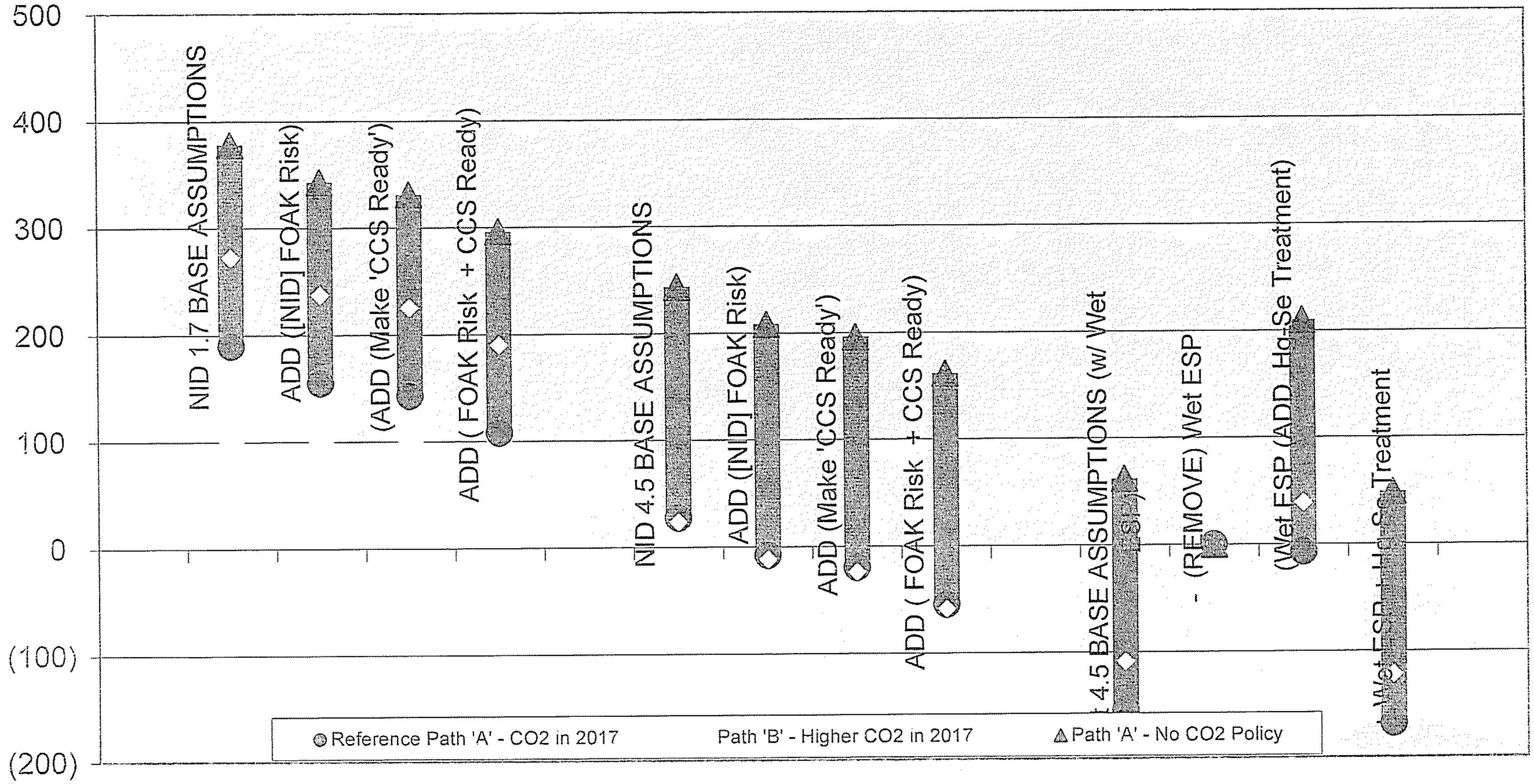
Add'l Notes

- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Big Sandy 2 FGD Retrofit -- *E&D Sensitivities*

Life Cycle (2010-2040) CPW of Revenue Requirements (2011 $)

FGD RETROFIT (vs RETIRE & REPLACE w/ CC) Savings / (Costs) ($Millions)



KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast; WPCo Remains w/ OPCo
(2007/2008 - 2030/2031)

BASE ("Going-in") Capacity Position (i.e., No 'New (Thermal) Gen' post-Dresden) (HAPs) "PHASE-IN" Unit Retirements ('11 IRP Preliminary) & Retrofit Profile

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
		Obligation to PJM										Resources								KPCo Position (MW)	
														Planned Capacity Additions							
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Units	MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2010 /11	(k)	1,208	(1)	0	1,208	0	0.955	1.083	1,309	0	1,309	1,465	81				1,384	5.01%	1,315	6	6
2011 /12	(k)	1,218	(9)	0	1,218	0	0.955	1.083	1,320	0	1,320	1,470	104				1,366	6.26%	1,280	(40)	(40)
2012 /13	(k)	1,253	(18)	0	1,253	3	0.950	1.080	1,350	0	1,350	1,470	56				1,414	7.15%	1,313	(37)	(37)
2013 /14	(k)	1,283	(31)	0	1,283	12	0.957	1.080	1,374	0	1,374	1,470	45				1,425	7.38%	1,320	(54)	(54)
2014 /15	(k)	1,300	(44)	(2)	1,298	22	0.956	1.081	1,381	0	1,381	1,470	(6)				1,476	7.66%	1,363	(18)	(18)
2015 /16		1,268	(52)	(4)	1,264	31	0.956	1.081	1,334	0	1,334	1,445	(5)				1,450	7.67%	1,339	5	5
2016 /17		1,272	(57)	(7)	1,265	34	0.956	1.081	1,333	0	1,333	1,447	(7)				1,454	7.67%	1,342	9	9
2017 /18		1,276	(60)	(9)	1,268	37	0.956	1.081	1,332	0	1,332	1,447	(8)				1,455	7.72%	1,343	11	11
2018 /19		1,283	(62)	(10)	1,273	37	0.956	1.081	1,337	0	1,337	1,447	(8)				1,455	7.72%	1,343	6	6
2019 /20		1,291	(64)	(15)	1,276	37	0.956	1.081	1,340	0	1,340	1,169	(5)				1,174	7.28%	1,089	(251)	(251)
2020 /21		1,296	(65)	(18)	1,278	37	0.956	1.081	1,343	0	1,343	1,169	(4)				1,173	7.28%	1,088	(255)	(255)
2021 /22		1,310	(66)	(20)	1,290	37	0.956	1.081	1,356	0	1,356	1,169	(3)				1,172	7.28%	1,087	(269)	(269)
2022 /23		1,321	(66)	(21)	1,300	37	0.956	1.081	1,366	0	1,366	1,169	(2)				1,171	7.28%	1,086	(280)	(280)
2023 /24		1,327	(66)	(23)	1,304	37	0.956	1.081	1,371	0	1,371	1,169	(1)				1,170	7.28%	1,085	(286)	(286)
2024 /25		1,334	(65)	(23)	1,310	37	0.956	1.081	1,378	0	1,378	1,169	0				1,169	7.28%	1,084	(294)	(294)
2025 /26		1,347	(65)	(24)	1,323	37	0.956	1.081	1,392	0	1,392	1,169	0				1,169	7.35%	1,083	(309)	(309)
2026 /27		1,357	(65)	(23)	1,333	37	0.956	1.081	1,403	0	1,403	1,169	0				1,169	7.35%	1,083	(320)	(320)
2027 /28		1,367	(65)	(23)	1,344	37	0.956	1.081	1,414	0	1,414	1,169	0				1,169	7.35%	1,083	(331)	(331)
2028 /29		1,375	(66)	(23)	1,352	37	0.956	1.081	1,423	0	1,423	1,169	0				1,169	7.35%	1,083	(340)	(340)
2029 /30		1,385	(65)	(23)	1,361	37	0.956	1.081	1,433	0	1,433	1,169	0				1,169	7.35%	1,083	(350)	(350)
2030 /31		1,396	(65)	(23)	1,372	37	0.956	1.081	1,445	0	1,445	1,169	0				1,169	7.35%	1,083	(362)	(362)

Notes: (a) Based on (March 2011) Load Forecast; WPCo Remains w/ OPCo (with implied PJM diversity factor)
Includes company MLR share of NCEMC

(b) Existing plus approved DR, EE, and IVV

(c) The impact of new DSM is delayed two years to represent either
(1) its impact on actual load feeding through the PJM load forecast process or
(2) verification prior to being offered into the PJM RPM auction.

(d) Demand Response approved by PJM in the prior planning year

(e) Installed Reserve Margin (IRM) = 15.0%(2007-2009), 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
2008/09: Rockport 1: 20 MW (turbine)
2009/10: Big Sandy 1: 0 MW (turbine)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(g) continued
FGD DERATES:
2015/16: Big Sandy 2: 25 MW; Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
RETIREMENTS (Under a HAPs "PHASE-IN" assumption):
2019/20: Big Sandy 1

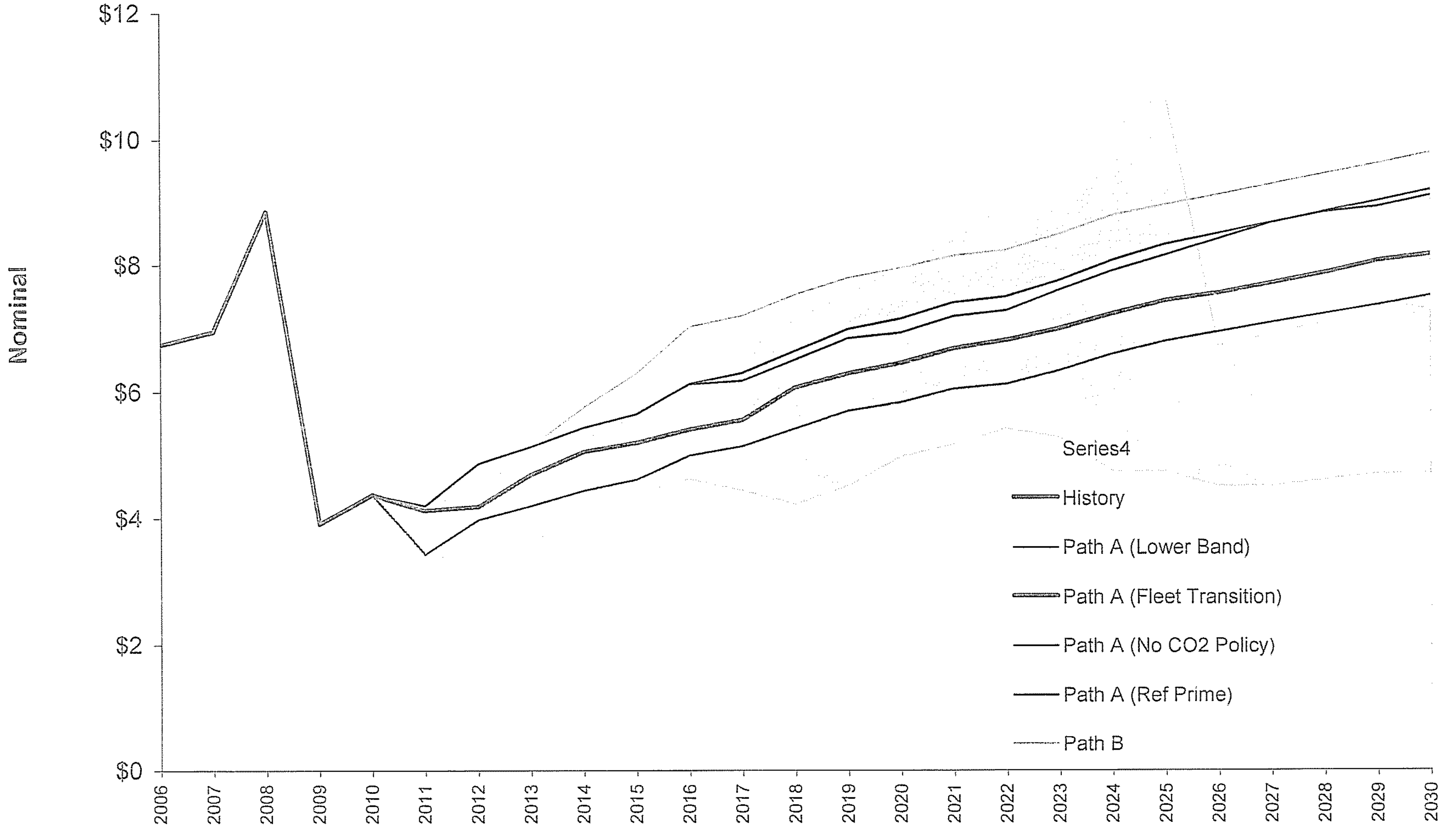
(h) Includes:
<Purchase> (from Constellation) of 315 MW in 2009/10-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2010/11-2012/13 (45 MW
RPM Auction Sales 2007/08 - 2013/14 (777, 1406, 1389, 1458, 1414, 696, 761) (M
3.6 MW capacity <credit> from SEPA's Philpot Dam via Blue Ridge contract
Estimated nominations for PJM EE ('passive' DR program) levels –reflected as a
as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year... Forecast represents latest Generation estim

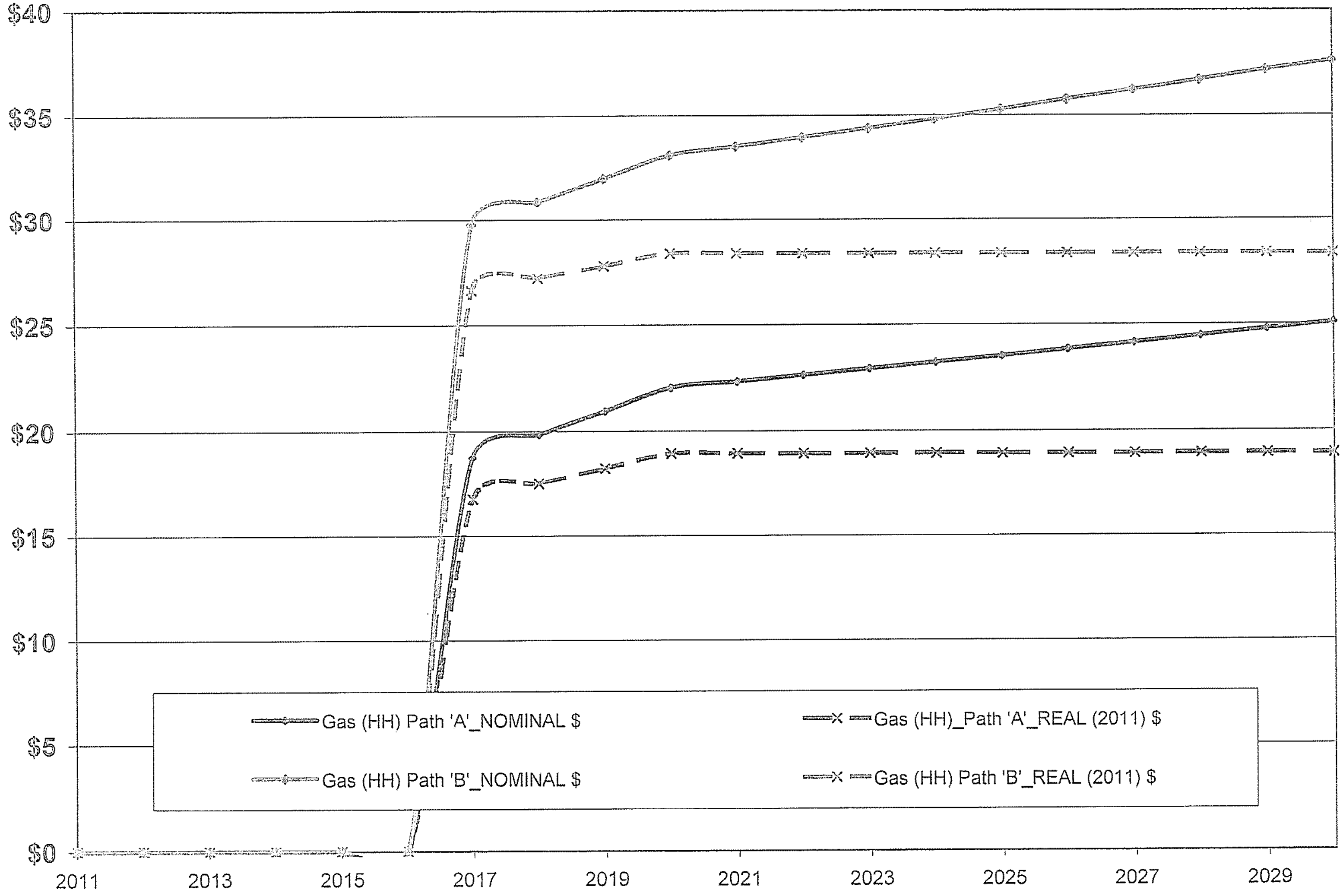
(k) PJM latest forecast of AEP Zonal coincident peak demande (allocated to Operating Co. LSEs)

Henry Hub Prices (nominal $/mmBtu)



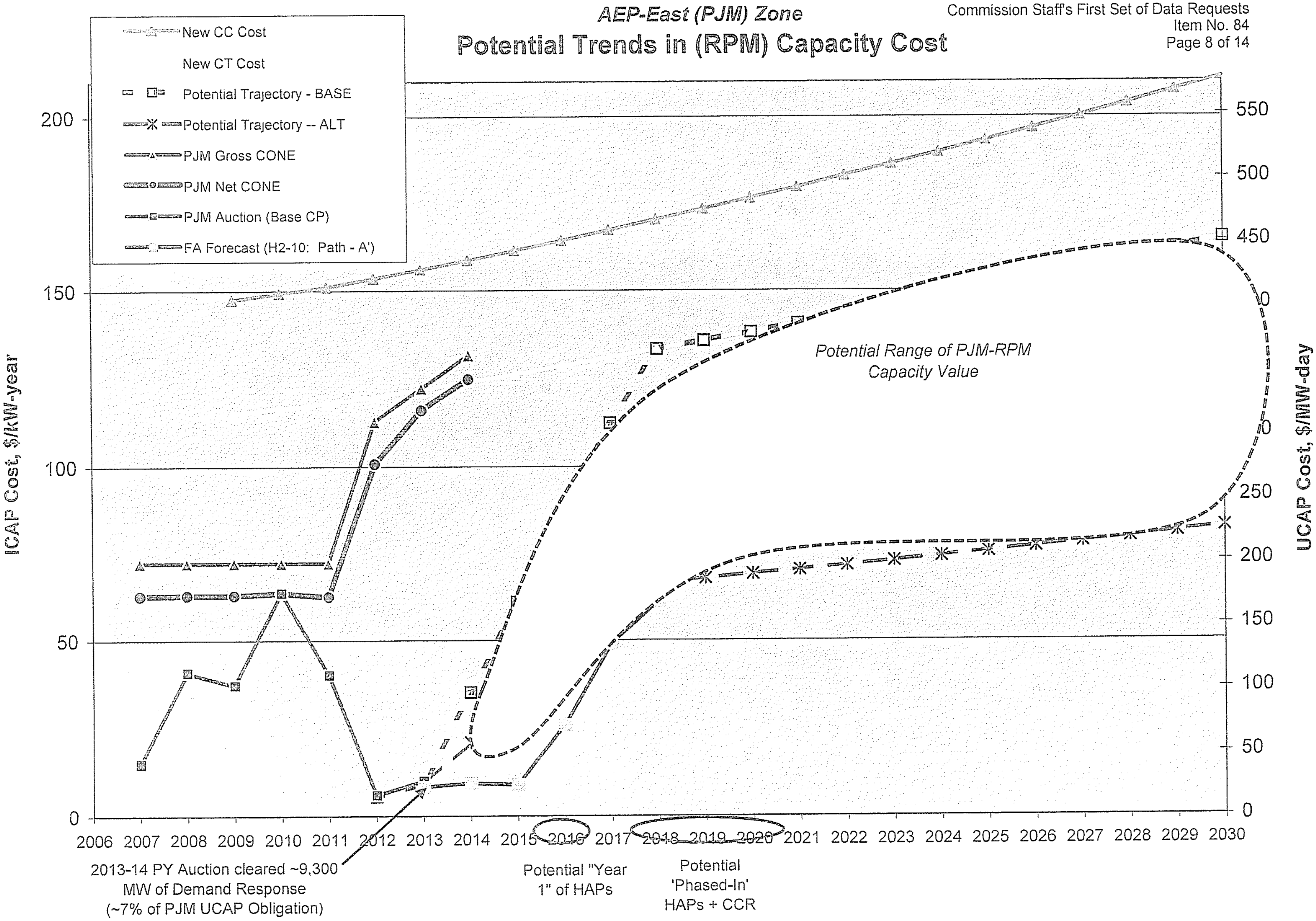
CO2 Prices (per Metric Tonne)

(AEP Internal Forecast)



AEP-East (PJM) Zone

Potential Trends in (RPM) Capacity Cost



2013-14 PY Auction cleared ~9,300
MW of Demand Response
(~7% of PJM UCAP Obligation)

Potential "Year
1" of HAPs

Potential
'Phased-In'
HAPs + CCR

Big Sandy Unit 2 Major Environmental Capital Expenditure Estimates

($Millions) *(post-Alloacted, excl AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:
RETROFITS											
FGD *(Per March LRP)*											
000009633 BS2 FGD Phase 2	5.7	38.3	81.4	145.6	122.8	13.1	-	-	-	-	401.2
000008348 Big Sandy FGD Landfill	1.5	1.7	7.3	10.1	10.1	8.6	0.1	-	-	-	37.9
BS002ASSC BS U2 FGD Associated	-	16.4	34.9	62.5	52.7	5.6	-	-	-	-	172.3
Total-FGD	**7.2**	**56.4**	**123.7**	**218.2**	**185.6**	**27.3**	**0.1**	**-**	**-**	**-**	**611.3**
CCR *(Per March LRP)*											
000019878 BS U2 Dry Fly Ash Conversion				-	-	-	-				-
000020353 BS U2 Bottom Ash Conversion				-	5.0	12.0	4.0	0.3	-	-	21.3
000020354 BS U2 Bottom Ash Ancillary Equ					-	-	-				-
000020356 BS U2 Ash WWT System			-	0.9	10.0	14.0	10.1	-	-	-	35.1
Total-CCR	**-**	**-**	**-**	**0.9**	**15.0**	**26.1**	**14.1**	**0.3**	**-**	**-**	**56.4**

(Generic) Combined Cycle Expenditure Estimates (768-MW)

($Millions) *(post-Alloacted, excl AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:
(Greenfield) CC *(per ERPI TAG)*											
(2X1 GE-7G; 768-MW)	-	16.8	69.1	354.0	453.5	0.0	0.0	0.0	-	-	893.5

FOM	/kW-Yr	$19.00
VOM	/Mwh	$3.40

Big Sandy Unit 1 CC (2x1; GE-7FA; 640-MW) Repowering Estimates

($Millions) *(post-Alloacted, excl AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:
BS1 Repowering *(per EP&FS prelim estimate)*											
(2X1 GE-7FA; 640-MW)	-	8.4	34.4	175.3	223.5	-	-	-	-	-	441.6

FOM	/kW-Yr	$25.88
VOM	/Mwh	$2.50

Kentucky Power Company
Capacity Resource Optimization
Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In") Commodity Pricing Including CCR-Related Costs
($000)

	Big Sandy 2 RETROFIT Alternatives							Big Sandy 2 RETIRE/REPLACE Alternatives							
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb* *BS1 Retire Accel.*	CASE 22 *NID 1.7 lb* ICAP Purch (MW)	CASE 23 * *NID/Dry 4.5 lb* 'BASE'	CASE 6 * *Dry 3.0 lb*	CASE 1 * *Wet 4.5 lb*	CASE 22 w/ BS1 FGD **	Retire & Repl - A *BS2 Replac w/* "Optimized" CC	Retire & Repl - B *BS2 Replac w/* "Like-Sized" CC	Retire & Repl - C *BS2 Replac w/ CC* Delay Retire by 4-Yr	Base Retire - ICAP *BS2 & BS1 Retire w/* *ICAP Purch (MW)*	Retire w/ ICAP+CC *BS2 Retire w/ ICAP thru '19* BS1&3 Repl w/ CC	Ret&BS1 Rpwr(+16-CC) *2x1 GEFA* +Add'l CC (2016) for RM	Ret&BS1 Rpwr(+20-CC) *2x1 GEFA* +Add'l CC (2020) for RM	Ret&BS1Rpwr+ICAP *2x1 GEFA* +ICAP Purch (MW)
				OPTION #1			*OPTION #2*		*OPTION #4*			*OPTION #3*		*OPTION #5*	
2010 *thru* 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement	BS2 Retirement		BS2 Retirement	BS2 Retirement	BS2 Retirement	BS2 Retirement	BS2 Retirement
2016		BS1 Retirement 1- 407 MW CC						1- 407 MW CC, 1 -645 MW CC	1 -768 MW CC		687	687	1 -614 MW BS1 CCRepwr 1- 407 MW CC	1-614 MW BS1 RPWR, 329 MW ICAP	1 -614 MW CCRepwr
2017											675	675		317 MW ICAP	317
2018											678	678		320 MW ICAP	320
2019	BS1 Retirement 1- 407 MW CC		BS1 Retirement 195	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC		BS1 Retirement	BS1 Retirement 1- 407 MW CC,	BS2 Retirement 1- 407 MW CC, BS1 Retirement	BS1 Retirement 933	BS1 Retirement 3- 407 MW CC		319 MW ICAP	319
2020 *thru* 2025			198							2- 407 MW CC	*Varies*			1- 407 MW CC,	*Varies*
2026			239								973				373
2027			251				1- 407 MW CC				985				371
2028			259								994				380
2029			266					1- 407 MW CC		1- 407 MW CC	1,000				386
2030			277								*Varies*				*Varies*
2031			288								1,023		1- 407 MW CC	1- 407 MW CC,	
2032 *thru* 2040			297								1,032				

(Life-Cycle) "G" REVENUE REQUIREMENT Summary:
(2011 $)

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Retires ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,407,894	$7,519,599	$7,548,321	$7,475,814	$7,512,327	$7,607,801	$7,398,843	$6,487,552	$7,344,456	$7,378,358	$7,280,009	$7,002,751
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$103,499	$102,794	$95,742	$141,015	$143,213	$129,285	$87,752	($727,425)	$98,236	$108,688	$60,477	($286,613)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,164,537	$7,232,334	$7,289,550	$7,304,395	$7,416,805	$7,452,579	$7,334,799	$7,381,637	$7,478,516	$7,343,713	$7,309,779	$7,258,743	$7,269,671	$7,219,532	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW -- Adj	$7,195,006	$7,272,803	$7,338,897	$7,355,236	$7,473,137	$7,519,926	$7,389,950								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.37	9.52	9.58	9.42	9.40	9.53	9.36	9.31	9.25	9.26	9.20	9.29

Variances:

Cost / <Savings> *vs. Retrofit w/ NID (4.5#)*	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC ('16)	BS1 Repower w/ Add'l CC ('20)	BS1 Repower+ICAP
CPW	($148,447)	($58,478)	$256,786		$111,705	$140,427	$67,920	$104,433	$199,907	($8,952)	($920,342)	($63,438)	($29,536)	($127,885)	($405,144)
Less: ICAP Revenue	$1,410	$13,583	$273,810		($705)	($7,757)	$37,515	$39,713	$25,785	($35,747)	($830,925)	($5,263)	$5,188	($43,023)	($390,112)
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($160,230)	($82,433)	$16,339		$117,981	$164,669	$34,714	$26,401	$123,280	($11,523)	($45,457)	($96,493)	($85,565)	($135,704)	($65,872)
% Variance	-2.2%	-1.1%	0.2%		1.6%	2.2%	0.5%	0.4%	1.7%	-0.2%	-0.6%	-1.3%	-1.2%	-1.8%	-0.9%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.20)	(0.11)			0.15	0.21	0.04	0.03	0.16	(0.01)	(0.06)	(0.12)	(0.11)	(0.17)	(0.00)

* These cases include Boiler modifications required to burn higher-sulfur coals
** Big Sandy 1 FGD costs do not include CCR related costs
*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted eff: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' Commodity Pricing (Path B - EPA 'Accelerated') Including CCR Related Costs

($000)

	Big Sandy 2 RETROFIT Alternatives				Big Sandy 2 RETIRE/REPLACE Alternatives				
	CASE 22	CASE 23 *	CASE 5 *	CASE 1 *	Retire & Repl - A	Retire & Repl - B	Ret. & BS1 Repower	Ret. & BS1 Repower	Ret&BS1Rpwr+ICAP
Technology / Fuel Type (Sulfur Content)	*NID/Dry 1.7 lb*	*NID/Dry 4.5 lb*	*Dry 3.0 lb*	*Wet 4.5 lb*	*BS2 Replac w/ "Optimized" CC*	*BS2 Replac w/ "Like-Sized" CC*	*2x1 GEFA +Add'l CC In '16*	*2x1 GEFA +Add'l CC in '20*	*2x1 GEFA +ICAP Purch (MW)*
		OPTION #1				*OPTION #4*		*OPTION #5*	
2010 *thru* 2015									
2016	BS2 FGD (22), 1- 407 MW CC BS1 Retirement	BS2 FGD (23), 1- 407 MW CC, BS1 Retirement	BS2 FGD (5), 1- 407 MW CC, BS1 Retirement	BS2 FGD (1), 1- 407 MW CC, BS1 Retirement	1- 407 MW CC, BS1&2 Retirement, 1 -645 MWCC	BS2 Retirement 1 -768 MW CC,	BS2 Retirement 1 -614 MW CCRepwr, 1- 407 MW CC	BS2 Retirement 1 -614 MW CCRepwr,	BS2 Retirement 1 -614 MW CCRepwr
2017 + 2018								317 MW ICAP 320 MW ICAP	
2019						BS1 Retirement 1- 407 MW CC,		319 MW ICAP	
2020								1- 407 MW CC,	
2021 *thru* 2028									
2029					1- 407 MW CC				
2030									
2031							1- 407 MW CC	1- 407 MW CC,	
2032 *thru* 2040									
(Life-Cycle) REVENUE REQUIREMENT Summary:									
	CASE 22	CASE 23	CASE 5	CASE 1	Retire & Repl - A	Retire & Repl - B	Ret. & BS1 Rpwr CC-'16	Ret. & BS1 Rpwr CC-'20	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,766,634	$8,002,005	$8,156,883	$8,099,538	$8,041,933	$7,993,579	$7,884,560	$7,677,290	$7,570,563
Less : ICAP Revenue	$112,302	$111,141	$104,754	$110,560	$82,423	$128,802	$61,314	$4,321	-$231,814
Plus: Cost to Retire BS 1&2	$0	$0	$0	$0	$12,523	$0	$0	$0	$0
GRAND TOTAL - CPW	$7,654,331	$7,890,864	$8,052,129	$7,988,977	$7,972,033	$7,864,777	$7,823,246	$7,672,969	$7,802,377
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$50,841	$56,332	$67,346					
GRAND TOTAL - CPW -- Adj	$7,694,800	$7,941,705	$8,108,461	$8,056,323					
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.80	10.12	10.33	10.26	10.16	10.02	9.97	9.78	9.94
Variances:									
Cost / <Savings> vs. Retrofit w/ NID (4.5#)	CASE 22		CASE 5	CASE 1	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('L:ike-Sized' CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	($235,371)		$154,878	$97,533	$39,928	($8,426)	($117,445)	($324,715)	($431,442)
Less : ICAP Revenue	$1,161		($6,387)	($581)	($28,718)	$17,661	($49,827)	($106,821)	($342,955)
Plus: Cost to Retire BS 1&2	$0		$0	$0	$12,523	$0	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)		$5,491	$16,505	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($246,905)		$166,756	$114,618	$30,328	($76,928)	($118,459)	($268,736)	($139,328)
% Variance	-3.1%		2.1%	1.4%	0.4%	-1.0%	-1.5%	-3.4%	-1.8%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.31)		0.21	0.15	0.04	(0.10)	(0.15)	(0.34)	(0.18)

* These cases include Boiler modifications required to burn higher-sulfur coals

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"... NO [CO2] Policy) Commodity Pricing Including CCR-Related Costs

($000)

	Big Sandy 2 RETROFIT Alternatives							Big Sandy 2 RETIRE/REPLACE Alts							
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb BS1 Retire Accel.*	CASE 22 NID 1.7 lb ICAP Purch (MW)	CASE 23 * *NID/Dry 4.5 lb*	CASE 6 * *Dry 3.0 lb*	CASE 1 * *Wet 4.5 lb*	CASE 22 w/ <u>BS1</u> FGD **	Retire & Repl - A *BS2 Replac w/ "Optimized" CC*	Retire & Repl - B *BS2 Replac w/ "Like-Sized" CC*	Retire & Repl - C *BS2 Replac w/ CC* Delay Retire by 4-Yr	Base Retire - ICAP *BS2 Retire w/* ICAP Purch (MW)	Base Retire - ICAP+CC *BS2 Retire w/ ICAP BS1 ('19) Repl w/ CC*	Ret. & BS1 Repowr *2x1 GEFA* +Add'l CC (2016) for RM	Ret. & BS1 Repower *2x1 GEFA* +Add'l CC (2020) for RM	Ret&BS1Rpwr+ICAP *2x1 GEFA +ICAP Purch (MW)*
				OPTION #1					*OPTION #4*			*OPTION #3*		*OPTION #5*	
2010 *thru* 2015															
2016	BS2 FGD (22)	BS2 FGD (22) BS1 Retirement 1- 407 MW CC	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement 1- 407 MW CC, 1 -645 MW CC	BS2 Retirement 1 -768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 614 MW CCRepwr 1- 407 MW CC	1 - BS2 Retirement 614 MW BS1 RPWR, 329 MW ICAP	1- BS2 Retirement 1 -614 MW CCRepwr 1- 407 MW CC
2017											675	675		317 MW ICAP	317
2018											678	678		320 MW ICAP	320
2019	BS1 Retirement 1- 407 MW CC		BS1 Retirement 195	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC		BS1 Retirement	BS1 Retirement 1- 407 MW CC,	BS2 Retirement 1- 407 MW CC, BS1 Retirement	BS1 Retirement 933	BS1 Retirement 3- 407 MW CC		319 MW ICAP	319
2020 *thru* 2026			190							2- 407 MW CC	933			1- 407 MW CC	*Varies*
2027			251				1- 407 MW CC				985				371
2028			259								994				380
2029			266					1- 407 MW CC		1- 407 MW CC	1,000				386
2030															
2031													1- 407 MW CC	1- 407 MW CC	
2032 *thru* 2040			277								1,011				*Varies*

(Life-Cycle) REVENUE REQUIREMENT Summary:

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	Base Retire - ICAP+CC	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	BS1 Repower+ICAP
Cumul. Present Worth (CPW)(A)	$6,446,250	$6,546,621	$6,250,773	$6,567,338	$6,688,324	$6,722,856	$6,614,026	$6,855,164	$6,913,605	$6,716,396	$5,660,876	$6,670,180	$6,682,246	$6,571,817	$6,233,298
Less : ICAP Revenue	$84,512	$93,614	($117,476)	$83,475	$82,956	$77,769	$88,922	$90,929	$102,368	$122,169	-$527,243	$78,723	$66,223	$27,829	-$204,278
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$6,361,738	$6,453,008	$6,376,391	$6,483,863	$6,605,368	$6,645,086	$6,525,103	$6,776,758	$6,811,237	$6,606,749	$6,282,920	$6,603,980	$6,616,022	$6,543,988	$6,437,576
Plus: Increm CPW for <u>10-yr</u> FGD Recovery	$40,469	$40,469	$49,348	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW – Adj	$6,402,206	$6,493,476	$6,425,739	$6,534,704	$6,661,700	$6,712,432	$6,580,254								
'Levelized (Life-Cycle) Cost' (cents/kWh)	8.16	8.27	8.19	8.33	8.49	8.55	8.38	8.63	8.68	8.42	8.00	8.41	8.43	8.34	8.20

Variances:

Cost / <Savings> vs. Retrofit w/ NID (4.5#)	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement Savings/<Cost> (vs. Replace w/ CC)	Base Retire - ICAP+CC	BS1 Repower w/ Add'l CC ('16)	BS1 Repower w/ Add'l CC ('20)	BS1 Repower+ICAP
CPW	($121,088)	($20,717)	($316,566)		$120,986	$155,517	$46,687	$287,826	$346,267	$149,057	($906,463)	$102,841	$114,907	$4,479	($334,040)
Less : ICAP Revenue	$1,037	$10,139	($200,951)		($519)	($5,706)	$5,447	$7,454	$18,893	$33,694	($610,716)	($4,752)	($17,252)	($55,646)	($287,753)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142		$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for <u>10-yr</u> FGD Recovery	($10,372)	($10,372)	($1,493)		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW – Adj	($132,498)	($41,228)	$351,019		$126,996	$177,728	$45,549	$242,054	$276,533	$72,045	($251,784)	$69,275	$81,318	$9,284	($97,128)
% Variance	-2.0%	-0.6%	6.2%		1.9%	2.7%	0.7%	3.7%	4.2%	1.1%	-3.9%	1.1%	1.2%	0.1%	-1.5%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.17)	(0.05)	#REF!		0.16	0.23	0.06	0.31	0.35	0.09	(0.32)	0.09	0.10	0.01	(0.12)

* These cases <u>include</u> Boiler modifications required to burn higher-sulfur coals

** Big Sandy 1 FGD costs do not include CCR related costs

Kentucky Power Company
Capacity Resource Optimization
Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"[REV]--"FLEET TRANSITION") Commodity Pricing Including CCR-Related Costs
($000)

	Big Sandy 2 RETROFIT Alternative							Big Sandy 2 RETIRE/REPLACE Alternatives							
	CASE 22	CASE 22 b	CASE 22	CASE 23 *	CASE 5 *	CASE 1 *	CASE 22	Retire & Repl - A	Retire & Repl - B	Retire & Repl - C	Base Retire - ICAP	Retire w/ ICAP+CC	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Technology / Fuel Type (Sulfur Content)	*NID/Dry 1.7 lb*	*NID/Dry 1.7 lb*	*NID 1.7 lb*	*NID/Dry 4.5 lb* *'BASE'*	*Dry 3.0 lb*	*Wet 4.5 lb*	w/ BS1 FGD **	*BS2 Replac w/*	*BS2 Replac w/*	*BS2 Replac w/ CC*	*BS2 & BS1 Retire w/*	*BS2 Retire w/ ICAP thru 2019*	*2x1 GEFA*	*2x1 GEFA*	*2x1 GEFA*
		BS1 Retire Accel.	ICAP Purch (MW)					"Optimized" CC	"Like-Sized" CC	Delay Retire by 4-Yr	*ICAP Purch (MW)*	BS1&3 Repl w/ CC	+Add'l CC (2016) for RM	+Add'l CC (2020) for RM	+ICAP Purch (MW)
				OPTION #1	*OPTION #5*	*OPTION #6*	*OPTION #7*	*OPTION #8*	*OPTION #4*	*OPTION #10*	*OPTION #11*	*OPTION #3*		*OPTION #5*	
2010 *thru* 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement 1- 407 MW CC, 1 -645 MW CC	BS2 Retirement 1 -768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 1 -614 MW CCRepwr 1- 407 MW CC	BS2 Retirement 1-614 MW BS1 RPWR, 329 MW ICAP	BS2 Retirement 1 -614 MW CCRepwr
2016		BS1 Retirement 1- 407 MW CC													
2017											675	675		317 MW ICAP	317
2018											678	676		320 MW ICAP	320
2019	BS1 Retirement 1- 407 MW CC		BS1 Retirement 195	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC		BS1 Retirement	BS1 Retirement 1- 407 MW CC,	BS2 Retirement 1- 407 MW CC, BS1 Retirement 2- 407 MW CC	BS1 Retirement 933	BS1 Retirement 3- 407 MW CC		319 MW ICAP	319
2020			198								*Varies*			1- 407 MW CC	319
2021 *thru* 2025															*Varies*
2026			239								973				373
2027			251				1- 407 MW CC				985				371
2028			259								994				360
2029			266					1- 407 MW CC		1- 407 MW CC	1,000				386
2030			277								*Varies*				*Varies*
2031			288								1,023		1- 407 MW CC		
2032 *thru* 2040			297								1,032				

(Life-Cycle) "G" REVENUE REQUIREMENT Summary:
(2011 $)

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Ret ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,466,412	$7,519,599	$7,548,321	$7,475,814	$7,512,327	$7,370,903	$7,398,943	$6,487,552	$7,157,764	$7,378,358	$7,042,336	$7,002,751
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$102,000	$102,794	$95,742	$141,015	$143,213	$127,823	$67,752	($727,425)	$100,601	$108,688	$69,552	($286,613)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,154,537	$7,232,334	$7,289,650	$7,364,411	$7,416,805	$7,452,579	$7,334,799	$7,369,114	$7,243,080	$7,331,190	$7,309,779	$7,069,686	$7,269,671	$6,972,785	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW -- Adj	$7,195,006	$7,272,803	$7,338,997	$7,415,262	$7,473,137	$7,519,925	$7,389,950								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.45	9.52	9.58	9.42	9.39	9.23	9.34	9.31	9.01	9.26	8.88	9.29

Variances:

Cost / <Savings> *vs. Retrofit w/ NID (4.5#)*	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	($206,965)	($116,996)	$355,314		$53,187	$81,909	$9,402	$45,915	($95,509)	($67,469)	($978,860)	($308,648)	($88,053)	($424,075)	($463,661)
Less: ICAP Revenue	$2,909	$15,082	$272,311		$794	($6,258)	$39,015	$41,212	$25,823	($34,248)	($829,426)	($1,399)	$6,687	($32,449)	($388,613)
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($220,247)	($142,450)	$76,355		$57,885	$104,672	($25,303)	($46,138)	($172,173)	($84,062)	($105,474)	($345,567)	($145,582)	($442,468)	($125,889)
% Variance	-3.0%	-1.9%	1.0%		0.8%	1.4%	-0.3%	-0.6%	-2.3%	-1.1%	-1.4%	-4.7%	-2.0%	-6.0%	-1.7%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.28)	(0.18)			0.07	0.13	(0.03)	(0.06)	(0.22)	(0.11)	(0.13)	(0.44)	(0.19)	(0.56)	(0.16)

* These cases include an incremental ~$172 MM capital spend associated with Boiler modifications required to burn higher-sulfur coals

** Big Sandy 1 FGD costs do not include CCR related costs

*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted eff: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company
Capacity Resource Optimization
Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"–"LOWER BAND") Commodity Pricing Including CCR-Related Costs
($000)

	Big Sandy 2 RETROFIT Alternative							Big Sandy 2 RETIRE/REPLACE Alternatives									
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb* *BS1 Retire Accel.*	CASE 22 *NID 1.7 lb* ICAP Purch (MW)	CASE 23 * *NID/Dry 4.5 lb* *'BASE'* *OPTION #1*	CASE 6 * *Dry 3.0 lb* *OPTION #5*	CASE 1 * *Wet 4.5 lb* *OPTION #6*	CASE 22 w/ BS1 FGD ** *OPTION #7*	Retire & Repl - A *BS2 Replac w/* "Optimized" CC *OPTION #8*	Retire & Repl - B *BS2 Replac w/* "Like-Sized" CC *OPTION #4*	Retire & Repl - C *BS2 Replac w/ CC* Delay Retire by 4-Yr *OPTION #10*	Base Retire - ICAP *BS2 & BS1 Retire w/* *ICAP Purch (MW)* *OPTION #11*	Retire w/ ICAP+CC *BS2 Retire w/ ICAP thru 2019* BS1&3 Repl w/ CC *OPTION #3*	Ret&BS1 Rpwr(+ 16-CC) *2x1 GEFA* +Add'l CC (2016) for RM	Ret&BS1 Rpwr(+ 20-CC) *2x1 GEFA* +Add'l CC (2020) for RM *OPTION #5*	Ret&BS1Rpwr+ICAP *2x1 GEFA* +ICAP Purch (MW)
2010 *thru* 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement 1- 407 MW CC, 1 -645 MW CC	BS2 Retirement 1 -768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 1 -614 MW CCRepwr 1- 407 MW CC	BS2 Retirement 1-614 MW BS1 RPWR, 329 MW ICAP	BS2 Retirement 1 -614 MW CCRepwr
2016		BS1 Retirement 1- 407 MW CC													
2017											675	675		317 MW ICAP	317
2018											678	678		320 MW ICAP	320
2019	BS1 Retirement 1- 407 MW CC		BS1 Retirement 195	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC		BS1 Retirement	BS1 Retirement 1- 407 MW CC,	BS2 Retirement 1- 407 MW CC, BS1 Retirement	BS1 Retirement 933	BS1 Retirement 3- 407 MW CC		310 MW ICAP	319
2020			198							2- 407 MW CC	*Varies*			1- 407 MW CC	319
2021 *thru* 2025															*Varies*
2026			239								973				373
2027			251				1- 407 MW CC				985				371
2028			259								994				380
2029			266					1- 407 MW CC		1- 407 MW CC	1,000				386
2030			277								*Varies*				*Varies*
2031			288								1,023		1- 407 MW CC		
2032 *thru* 2040			297								1,032				

(Life-Cycle) "G" REVENUE REQUIREMENT Summary:
(2011 $)

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Ret ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,420,985	$7,519,599	$7,548,321	$7,475,814	$7,512,327	$7,126,654	$7,398,943	$6,487,552	$6,960,281	$7,378,358	$6,815,225	$7,002,751
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$97,865	$102,794	$95,742	$141,015	$143,213	$121,919	$67,752	($727,425)	$96,663	$108,688	$58,749	($206,613)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,154,537	$7,232,334	$7,289,550	$7,323,120	$7,416,805	$7,452,579	$7,334,799	$7,369,114	$7,004,736	$7,331,190	$7,309,779	$6,876,141	$7,269,671	$6,766,476	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW -- Adj	$7,195,006	$7,272,803	$7,338,897	$7,373,961	$7,473,137	$7,519,925	$7,389,950								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.39	9.52	9.58	9.42	9.39	8.92	9.34	9.31	8.76	9.26	8.61	9.20

Variances:

Cost / <Savings> *vs. Retrofit w/ NID (4.5#)*	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	($161,538)	($71,569)	$309,887		$98,614	$127,336	$54,829	$91,342	($294,331)	($22,042)	($933,433)	($460,704)	($42,627)	($605,760)	($418,234)
Less: ICAP Revenue	$7,045	$19,217	$268,175		$4,929	($2,123)	$43,150	$45,348	$24,054	($30,112)	($825,290)	($1,202)	$10,823	($39,115)	($304,477)
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($178,956)	($101,159)	$35,064		$99,176	$145,963	$15,988	($4,847)	($369,225)	($42,771)	($64,183)	($497,820)	($104,291)	($607,486)	($84,598)
% Variance	-2.4%	-1.4%	0.5%		1.3%	2.0%	0.2%	-0.1%	-5.0%	-0.6%	-0.9%	-6.8%	-1.4%	-8.2%	-1.1%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.23)	(0.13)			0.13	0.19	0.02	(0.01)	(0.47)	(0.05)	(0.08)	(0.63)	(0.13)	(0.79)	(0.11)

* These cases include an incremental ~$172 MM capital spend associated with Boiler modifications required to burn higher-sulfur coals
** Big Sandy 1 FGD costs do not include CCR related costs
*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted eff: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company

REQUEST

Refer to page 9 of the Wohnhas Testimony, lines 8-13. It states, "[t]hose plans based upon a preliminary analysis that indicated repowering of Big Sandy Unit 1 would be the least cost alternative. Subsequently, and as explained by Witness Walton, a more robust and detailed analysis was performed on the four alternatives. That completed analysis revealed that contrary to the preliminary review, the low cost is installation of a DFGD on Big Sandy Unit 2."

a. Explain when the preliminary analysis first began.

b. Explain when the preliminary analysis was completed.

c. Provide the cost of the preliminary analysis.

d. Provide who requested that the preliminary analysis be performed.

e. Explain what circumstances changed between the conclusion of the preliminary a analysis and the completed analysis that revealed the low cost alternative is to install a dry FGD on Big Sandy Unit 2.

RESPONSE

a. The high level indicative cost estimate used in the first financial analysis first began in November 2010.

b. The high level indicative cost estimate used in the first financial analysis was completed in June 2011.

c. The high level indicative cost estimate used an early estimate iteration from the first quarter of 2011 (prior to the date of finalization indicated in (b) above) in the initial financial analysis that indicated that the option of repowering Big Sandy 1 was approximately$441 million.

d. American Electric Power Service Corporation (AEPSC) and Kentucky Power Company requested the cost estimates be developed and the preliminary analysis be performed.

e. The initial financial analysis used to support the assumption that repowering Big Sandy 1 was the least cost option used a high level indicative cost estimate that was finished in June 2011 as the assumption.

A subsequent, highly detailed, cost estimate provided by independent consultants (Sargent&Lundy) was then initiated on the completion of the indicative cost estimate after the preliminary analysis revealed the repowering option as potentially the least cost. This Big Sandy 1 NGCC repowering cost estimate was developed employing the same rigorous process, design basis document substantiation, and commodity estimating as the other Big Sandy FGD and Brownfield NGCC cost estimates placing them on a comparative level. This cost estimate was completed in September 2011 and indicated that the costs of repowering Big Sandy 1 were considerably higher than the indicative estimate. The final cost estimate was used in the final financial analysis and indicated the installation of an FGD was the least cost option for KPCo customers.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 9 of the Wohnhas Testimony, lines 22-23. Identify the likely sources for the
4.5 lbs. SO2/MMBtu coal.

RESPONSE

As described on page 10 of the Wohnhas testimony, lines 18-21, the 4.5 lb. SO2/MMBTU coal would be an approximately 50:50 blend of either Northern Appalachia (NAPP) or Illinois Basin (ILB) coal to be blended with Central Appalachian (CAPP) coal.

The CAPP coal in the blend will have a sulfur content less than 4.5 lb. SO2/MMBTU, while the NAPP and/or ILB coals will have a sulfur content greater than 4.5 lb. SO2/MMBTU.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the Wohnhas Testimony, page 13, lines 12-17 and 21, to page 14, line 7.

a. Provide the type of FGD that was the topic of the preliminary investigation.

b. Provide who performed the investigation, for example AEPSC employees or an outside consultant.

c. Explain whether the FGD investigation performed was strictly for the Big Sandy plant or for other AEP generating plants. If it included other plants, provide the names of those plants.

d. Provide a detailed description of the type of work performed and a breakdown of the $15,212,425 by type of costs.

e. Explain whether there were more effective technologies developed between 2006 and the date of the completed analysis, as referred to on lines 2 and 3 on page 14 of the Wohnhas Testimony.

RESPONSE

a. The preliminary investigation focused on wet flue gas desulfurization (WFGD) systems.

b. The investigation was completed by AEPSC in cooperation with Parsons E&C.

c. The investigation was specific to Big Sandy Plant.

d. Please refer to the Company's response to KPSC 1-18.

e. Yes, as indicated in the Walton testimony on page 23 lines 13 through 15, the NID dry FGD technology emerged domestically after 2006, which is more economically suitable to comply with final and proposed EPA regulations.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to pages 14-15 of the Wohnhas Testimony.

a. Explain the basis, whether it be a study or analysis, for the 15-year depreciation period.

b. Provide the current depreciation rates utilized for the generating equipment at the Big Sandy plant.

c. Provide, by generating plant, the depreciation periods used for the scrubbers already in service on the AEP System.

RESPONSE

a. There was no study or analysis, just the concern of recovery as stated in my testimony, page 15, lines 1-5.

b. All of the Generating equipment with the exception of the SCR Catalyst is being depreciated using a depreciation rate of 3.78%. The SCR Catalyst is being depreciated over its useful life with Catalyst Layer 1 having a retirement date of May 2018, Catalyst Layer 2 having a retirement date of May 2022 and Catalyst Layer 3 having a retirement date of May 2013.

c. Please see page 2 of this response.

WITNESS: Ranie K Wohnhas

AEP Plants with Scrubbers

Plant	AEP Affiliate Company	Depreciation Period
Gavin Units 1 & 2	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Mitchell Units 1 & 2	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Cardinal Unit 1	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Conesville Units 4 - 6	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Stuart Units 1 - 4	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Zimmer Unit 1	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Amos Units 1 - 3	Appalachian Power Company (APCO), Unit 3 is co-owned by APCO and Ohio Power	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Mountaineer Unit 1	Appalachian Power Company (APCO)	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Oklaunion	Public Service of Oklahoma	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Pirkey	Southwestern Electric Power Company	Company is in Arkansas, Louisana, and Texas. Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Dolet Hills	Southwestern Electric Power Company	Company is in Arkansas, Louisana, and Texas. Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.

Kentucky Power Company

REQUEST

Refer to pages 14-15 of the Wohnhas Testimony.

a. Under Option #1, what is the expected remaining useful life of the existing equipment?

b. Under Option #1, if the expected remaining life of the existing equipment is longer than 15 years, explain why it would not be appropriate to match the depreciation lives of the new environmental control equipment with the expected remaining lives of the existing equipment.

c. Provide the rationale for thinking that the Commission would not allow the continued recovery of all authorized expenses.

d. For Options #1 through #4, explain whether the depreciation lives of the equipment in the various options were the same. If not, why.

RESPONSE

a. Please see response to Commission Staff's First Set of Data Requests, Item No. 12.

b. It is an appropriate option and has been used by AEP as shown on page 2 of the response to Staff 1-90. However, all of those showed an estimated plant life of 60 years. Even though the Company has stated that the service life for Big Sandy Unit 2 could approach 70 years, it is not a guarantee and thus 15 years (service life of 60 years) is more appropriate.

c. The Company is not stating that the Commission would not allow recovery of all authorized expenses.

d. Option #1 was the only option with a 15 year depreciation life. Options #2 and #3 used the remaining life of the equipment because they would be gas units which will not have EPA regulations to hinder their operations. Option #4 is a market option and thus depreciation does not apply.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Explain how the 15 year depreciation period for the Big Sandy scrubber referred to on pages 14-15 of the Wohnhas Testimony compares with the statement made on page 15 of the Weaver Testimony, lines 14-18, that states "these evaluations were performed over a 30-year economic study period (2011 through 2040) in the Strategist tool so as to emulate the potential life-cycle of the respective asset alternatives as well as in recognition of the various "down-stream" impact on KPCo overall resource planning needs."

RESPONSE

The depreciation period for the Big Sandy retrofit is the appropriate recovery period for the incremental investment and should not be confused with the appropriate option "economic study period". The overall economic (2011-2040) study period captured in the long-term Strategist modeling described by Mr. Weaver simply reflects a period sufficient in length so as to capture any life-cycle cost stream/cash flow vagaries among the options evaluated. For instance, the estimated recovery period of the incremental investments associated with the natural gas solutions (Options #2 and #3 in Mr. Weaver's testimony) were assumed to be 20-years (from 2016 through 2035) and 30-years (from 2016 through 2045), respectively. Also, as described in response to Staff 1-12, it was assumed that the reasonable service life for the Big Sandy 2 unit would be through 2040.

Therefore, for consistency, the overall modeling study period would typically attempt to capture the longest of the respective option recovery periods. That said, 30-years (through 2040) is typically viewed as a reasonable length for such long-term comparative evaluations where the results are shown in "present value" dollars, due to the fact that the "present value factor" of a nominal cost 30 years into the future would be very minimal in today's dollars. Hence any differences in costs/cash flow among any 'Plan A' vs. 'Plan B' would be minute at that point, after discounting to today's dollars, *even if*, in this case, Option #3 economics could be extended on out to 2045.

WITNESS: Ranie K Wohnhas

KPSC Case No. 2011-00401
Commission Staff's First Set of Data Requests
Order Dated January 13, 2012
Item No. 91
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to the Wohnhas Testimony at page 15, lines 1-5. One of the reasons given for depreciating the FGD at Big Sandy Unit 2 over 15 years is to reduce the risk of stranded investment in the future.

a. What is Kentucky Power's assessment of the risk of the FGD becoming a stranded investment?

b. Explain why exisitng customers should pay for this future risk.

RESPONSE

a With the increasingly stringent and ever changing position of the EPA and its rule making, the Company believes that it is a medium risk that future EPA rules would result in stranded investment in the DFGD in the absence of a 15-year depreciation period.

b. The investment is being made for the benefit of current customers. Most of the Company's current customers will also be customers in 15 and 25 years from now. The Company is trying to match as best it can the cost to the cost causer in the event the risk is realized.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 16 of the Wohnhas Testimony, lines 15-20. Explain how Kentucky Power purposes to recover the cost of CSAPR emission allowances related to sales to affiliates and off system sales.

RESPONSE

The cost of CSAPR allowances related to sales to affiliates is recovered through base rates. The cost of CSAPR allowances related to off system sales is recovered through the system sales clause.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 17 of the Wohnhas Testimony, lines 1-4.

a. The estimated expense for CSAPR emission allowances for 2012 is $6.2 million. Provide support for this estimate.

b. For 2012, a gain of $650,000 from the sale of NOX, allowances under CSAPR is shown. Provide support for this estimate.

RESPONSE

a. The forecasted expense of $6.2 million refers only to CSAPR SO2 emission allowances. At the time the forecast for 2012 was prepared, it was assumed that KPCo would be required to purchase [redacted] allowances at a price of [redacted] per allowance to operate over 2012 and supply a buffer of allowances.

b. At the time the forecast was prepared it was assumed that in 2012 KPCo would be able to sell [redacted] allowances at a forecasted market price of [redacted] per allowance, to realize a gain of $650,000.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Explain whether AEP has placed scrubbers on any 800 MW or 1,300 MW units on its system and, if so, identify the plant and unit. If any have been installed, provide the average time to design, construct, and install the scrubbers on the 800 MW or 1300 MW units, by plant and unit.

RESPONSE

Please see response to Commission Staff's First Set of Data Requests, Item No. 23, Attachment 1 for FGD installations on 800 MW or 1,300 MW units since 2004.

Scrubbers were also installed at Gavin 1 (1,300 MW) and Gavin 2 (1,300 MW) in the mid 1990's, using a different technology and approach at a total cost of approximately $668 million.

WITNESS: Robert L Walton