STITES & HARBISON PLLC
ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

September 8, 2006

Michele M. Whittington
(502) 209-1215
(502) 223-4124 FAX
mwhittington@stites.com

HAND DELIVERED

Beth O'Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: Kentucky Power Company
PSC Case No. 2006-00307

Dear Ms. O'Donnell:

Enclosed please find and accept for filing the original and five (5) copies of Kentucky Power Company's Responses to the Commission's August 24, 2006 First Set of Data Requests. By copy of this letter, copies are being served on KIUC and the Attorney General.

If you have any questions, please feel free to contact me.

Sincerely,

STITES & HARBISON, PLLC

Michele M. Whittington

Michele M. Whittington

MMW/las
Enclosures
cc: Elizabeth E. Blackford
Michael L. Kurtz

KE057:KE113:14671:1:FRANKFORT

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION FO KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF AN AMENDED COMPLIANCE	)	
PLAN FOR PURPOSES OF RECOVERING ADDITIONAL	)	**CASE NO. 2006-00307**
COSTS OF POLLUTION CONTROL FACILITIES AND	)	
TO AMEND ITS ENVIRONMENTAL COST RECOVERY	)	
SURCHARGE TARIFF	)	

KENTUCKY POWER COMPANY RESPONSES TO COMMISSION FIRST SET DATA REQUEST

September 8, 2006

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of John M McManus ("McManus Testimony"), page 3. Concerning the environmental projects related to compliance with the Clean Water Act ("CWA") and the Solid Waste Disposal Act ("SWDA"),

a. Provide copies of the applicable requirements of the CWA and SWDA referenced in the McManus Testimony.

b. Explain in detail how complying with the referenced requirements of the CWA and SWDA are applicable to coal combustion wastes and by-productions from facilities utilized for the production of energy from coal.

RESPONSE

a. Attached are copies of 33 U.S.C. 1342 and 42 U.S.C. 6944.

b. 33 U.S.C. 1342 is the portion of the CWA that regulates the discharge of waste water to a river, stream, or other surface water through the issuance of a permit by the applicable permitting authority. Such permits contain discharge limitations based on technological or water quality based standards that are intended to protect the uses of the receiving stream. As described on page 14 of the McManus Testimony, the installation of the FGD systems necessitates installation of an FGD Purge Stream Water Treatment System to assure compliance with the requirements of the CWA. The FGD systems use a water and limestone-based scrubbing system, and generate a wet gypsum-like by-product. Most of the water recirculates through the scrubber system, but occasionally the system must be purged of some of this water, and fresh water must be added. The purge water contains high concentrations of suspended solids. The purge water cannot be discharged directly to surface water, or indirectly through existing plant waste water systems, without further treatment to remove a portion of these solids and meet the limitations imposed under the CWA and our discharge permits.

The coal combustion waste and other by-products are "solid waste" as defined in the SWDA. 42 U.S.C. 6903(27) defined "solid waste" to include "garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations. . .". 42 U.S.C. 6944 requires each state to establish standards for sanitary landfills (including landfills that accept industrial solid wastes) and prohibits "open dumping" of solid wastes. Section 6944 also mandates that the state plans must contain requirements that all "solid waste" either be (a) "utilized for resource recovery;" or (b) disposed of in sanitary landfills or in some other "environmentally sound matter." Thus, the by-products from the FGD systems that cannot be re-used will need to be disposed in permitted solid waste disposal facilities at Amos and Cardinal Plants. Off-specification gypsum from the Mitchell Plant FGD system, and a portion of the Cardinal FGD waste will be directed to the landfill at Mountaineer Plant. In addition, the existing flyash disposal facilities that accept coal combustion wastes need to be expanded at Sporn and Rockport Plant. Each of these facilities will meet applicable state standards developed pursuant to 42 U.S.C. 6944.

WITNESS: John M McManus

KPSC Case No. 2006-00307
Commission Staff First Set Data Request
Order Dated August 24, 2006
Item No.1
Page 3 of 16

33 USC §1342. National Pollutant Discharge Elimination System

(a) Permits for discharge of pollutants

(1) Except as provided in sections 1328 and 1344 of this title, the Administrator may, after opportunity for public hearing issue a permit for the discharge of any pollutant, or combination of pollutants, notwithstanding section 1311(a) of this title, upon condition that such discharge will meet either (A) all applicable requirements under sections 1311, 1312, 1316, 1317, 1318, and 1343 of this title, or (B) prior to the taking of necessary implementing actions relating to all such requirements, such conditions as the Administrator determines are necessary to carry out the provisions of this chapter.

(2) The Administrator shall prescribe conditions for such permits to assure compliance with the requirements of paragraph (1) of this subsection, including conditions on data and information collection, reporting, and such other requirements as he deems appropriate.

(3) The permit program of the Administrator under paragraph (1) of this subsection, and permits issued thereunder, shall be subject to the same terms, conditions, and requirements as apply to a State permit program and permits issued thereunder under subsection (b) of this section.

(4) All permits for discharges into the navigable waters issued pursuant to section 407 of this title shall be deemed to be permits issued under this subchapter, and permits issued under this subchapter shall be deemed to be permits issued under section 407 of this title, and shall continue in force and effect for their term unless revoked, modified, or suspended in accordance with the provisions of this chapter.

(5) No permit for a discharge into the navigable waters shall be issued under section 407 of this title after October 18, 1972. Each application for a permit under section 407 of this title, pending on October 18, 1972, shall be deemed to be an application for a permit under this section. The Administrator shall authorize a State, which he determines has the capability of administering a permit program which will carry out the objectives of this chapter to issue permits for discharges into the navigable waters within the jurisdiction of such State. The Administrator may exercise the authority granted him by the preceding sentence only during the period which begins on October 18, 1972, and ends either on the ninetieth day after the date of the first promulgation of guidelines required by section 1314(i)(2) of this title, or the date of approval by the Administrator of a permit program for such State under subsection (b) of this section, whichever date first occurs, and no such authorization to a State shall extend beyond the last day of such period. Each such permit shall be subject to such conditions as the Administrator determines are necessary to carry out the provisions of this chapter. No such permit shall issue if the Administrator objects to such issuance.

(b) State permit programs

At any time after the promulgation of the guidelines required by subsection (i)(2) of section 1314 of this title, the Governor of each State desiring to administer its own permit program for discharges into navigable waters within its jurisdiction may submit to the Administrator a full and complete description of the program it proposes to establish and administer under State law or under an interstate compact. In addition, such State shall submit a statement from the attorney general (or the attorney for those State water pollution control agencies which have independent legal counsel), or from the chief legal officer in the case of an interstate agency, that the laws of such State, or the interstate compact, as the case may be, provide adequate authority to carry out the described program. The Administrator shall approve each submitted program unless he determines that adequate authority does not exist:

(1) To issue permits which -

(A) apply, and insure compliance with, any applicable requirements of sections 1311, 1312, 1316, 1317, and 1343 of this title;

(B) are for fixed terms not exceeding five years; and

(C) can be terminated or modified for cause including, but not limited to, the following:

(i) violation of any condition of the permit;

(ii) obtaining a permit by misrepresentation, or failure to disclose fully all relevant facts;

(iii) change in any condition that requires either a temporary or permanent reduction or elimination of the permitted discharge;

(D) control the disposal of pollutants into wells;

(2)(A) To issue permits which apply, and insure compliance with, all applicable requirements of section 1318 of this title; or

(B) To inspect, monitor, enter, and require reports to at least the same extent as required in section 1318 of this title;

(3) To insure that the public, and any other State the waters of which may be affected, receive notice of each application for a permit and to provide an opportunity for public hearing before a ruling on each such application;

(4) To insure that the Administrator receives notice of each application (including a copy thereof) for a permit;

(5) To insure that any State (other than the permitting State), whose waters may be affected by the issuance of a permit may submit written recommendations to the permitting State (and the Administrator) with respect to any permit application and, if any part of such written recommendations are not accepted by the permitting State, that the permitting State will notify such affected State (and the Administrator) in writing of its failure to so accept such recommendations together with its reasons for so doing;

(6) To insure that no permit will be issued if, in the judgment of the Secretary of the Army acting through the Chief of Engineers, after consultation with the Secretary of the department in which the Coast Guard is operating, anchorage and navigation of any of the navigable waters would be substantially impaired thereby;

(7) To abate violations of the permit or the permit program, including civil and criminal penalties and other ways and means of enforcement;

(8) To insure that any permit for a discharge from a publicly owned treatment works includes conditions to require the identification in terms of character and volume of pollutants of any significant source introducing pollutants subject to pretreatment standards under section 1317(b) of this title into

such works and a program to assure compliance with such pretreatment standards by each such source, in addition to adequate notice to the permitting agency of (A) new introductions into such works of pollutants from any source which would be a new source as defined in section 1316 of this title if such source were discharging pollutants, (B) new introductions of pollutants into such works from a source which would be subject to section 1311 of this title if it were discharging such pollutants, or (C) a substantial change in volume or character of pollutants being introduced into such works by a source introducing pollutants into such works at the time of issuance of the permit. Such notice shall include information on the quality and quantity of effluent to be introduced into such treatment works and any anticipated impact of such change in the quantity or quality of effluent to be discharged from such publicly owned treatment works; and

(9) To insure that any industrial user of any publicly owned treatment works will comply with sections 1284(b), 1317, and 1318 of this title.

(c) Suspension of Federal program upon submission of State program; withdrawal of approval of State program; return of State program to Administrator

(1) Not later than ninety days after the date on which a State has submitted a program (or revision thereof) pursuant to subsection (b) of this section, the Administrator shall suspend the issuance of permits under subsection (a) of this section as to those discharges subject to such program unless he determines that the State permit program does not meet the requirements of subsection (b) of this section or does not conform to the guidelines issued under section 1314(i)(2) of this title. If the Administrator so determines, he shall notify the State of any revisions or modifications necessary to conform to such requirements or guidelines.

(2) Any State permit program under this section shall at all times be in accordance with this section and guidelines promulgated pursuant to section 1314(i)(2) of this title.

(3) Whenever the Administrator determines after public hearing that a State is not administering a program approved under this section in accordance with requirements of this section, he shall so notify the State and, if appropriate corrective action is not taken within a reasonable time, not to exceed ninety days, the Administrator shall withdraw approval of such program. The Administrator shall not withdraw approval of any such program unless he shall first have notified the State, and made public, in writing, the reasons for such withdrawal.

(4) Limitations on partial permit program returns and withdrawals. - A State may return to the Administrator administration, and the Administrator may withdraw under paragraph (3) of this subsection approval, of -

(A) a State partial permit program approved under subsection (n)(3) of this section only if the entire permit program being administered by the State department or agency at the time is returned or withdrawn; and

(B) a State partial permit program approved under subsection (n)(4) of this section only if an entire phased component of the permit program being administered by the State at the time is returned or withdrawn.

(d) Notification of Administrator

(1) Each State shall transmit to the Administrator a copy of each permit application received by such State and provide notice to the

Administrator of every action related to the consideration of such permit application, including each permit proposed to be issued by such State.

(2) No permit shall issue (A) if the Administrator within ninety days of the date of his notification under subsection (b)(5) of this section objects in writing to the issuance of such permit, or (B) if the Administrator within ninety days of the date of transmittal of the proposed permit by the State objects in writing to the issuance of such permit as being outside the guidelines and requirements of this chapter. Whenever the Administrator objects to the issuance of a permit under this paragraph such written objection shall contain a statement of the reasons for such objection and the effluent limitations and conditions which such permit would include if it were issued by the Administrator.

(3) The Administrator may, as to any permit application, waive paragraph (2) of this subsection.

(4) In any case where, after December 27, 1977, the Administrator, pursuant to paragraph (2) of this subsection, objects to the issuance of a permit, on request of the State, a public hearing shall be held by the Administrator on such objection. If the State does not resubmit such permit revised to meet such objection within 30 days after completion of the hearing, or, if no hearing is requested within 90 days after the date of such objection, the Administrator may issue the permit pursuant to subsection (a) of this section for such source in accordance with the guidelines and requirements of this chapter.

(e) Waiver of notification requirement

In accordance with guidelines promulgated pursuant to subsection (i)(2) of section 1314 of this title, the Administrator is authorized to waive the requirements of subsection (d) of this section at the time he approves a program pursuant to subsection (b) of this section for any category (including any class, type, or size within such category) of point sources within the State submitting such program.

(f) Point source categories

The Administrator shall promulgate regulations establishing categories of point sources which he determines shall not be subject to the requirements of subsection (d) of this section in any State with a program approved pursuant to subsection (b) of this section. The Administrator may distinguish among classes, types, and sizes within any category of point sources.

(g) Other regulations for safe transportation, handling, carriage, storage, and stowage of pollutants

Any permit issued under this section for the discharge of pollutants into the navigable waters from a vessel or other floating craft shall be subject to any applicable regulations promulgated by the Secretary of the department in which the Coast Guard is operating, establishing specifications for safe transportation, handling, carriage, storage, and stowage of pollutants.

(h) Violation of permit conditions; restriction or prohibition upon introduction of pollutant by source not previously utilizing treatment works

In the event any condition of a permit for discharges from a treatment works (as defined in section 1292 of this title) which is publicly owned is violated, a State with a program approved under subsection (b) of this section or the Administrator, where no State program is approved or where the Administrator determines pursuant to section 1319(a) of this title that a State with an approved program has not commenced appropriate enforcement action with respect to such permit, may proceed in a court of competent jurisdiction to restrict or prohibit the introduction of any pollutant into such treatment works by a source not utilizing such treatment works prior to the finding that such condition was violated.

(i) Federal enforcement not limited

Nothing in this section shall be construed to limit the authority of the Administrator to take action pursuant to section 1319 of this title.

(j) Public information

A copy of each permit application and each permit issued under this section shall be available to the public. Such permit application or permit, or portion thereof, shall further be available on request for the purpose of reproduction.

(k) Compliance with permits

Compliance with a permit issued pursuant to this section shall be deemed compliance, for purposes of sections 1319 and 1365 of this title, with sections 1311, 1312, 1316, 1317, and 1343 of this title, except any standard imposed under section 1317 of this title for a toxic pollutant injurious to human health. Until December 31, 1974, in any case where a permit for discharge has been applied for pursuant to this section, but final administrative disposition of such application has not been made, such discharge shall not be a violation of (1) section 1311, 1316, or 1342 of this title, or (2) section 407 of this title, unless the Administrator or other plaintiff proves that final administrative disposition of such application has not been made because of the failure of the applicant to furnish information reasonably required or requested in order to process the application. For the 180-day period beginning on October 18, 1972, in the case of any point source discharging any pollutant or combination of pollutants immediately prior to such date which source is not subject to section 407 of this title, the discharge by such source shall not be a violation of this chapter if such a source applies for a permit for discharge pursuant to this section within such 180-day period.

(l) Limitation on permit requirement

(1) Agricultural return flows

The Administrator shall not require a permit under this section for discharges composed entirely of return flows from irrigated agriculture, nor shall the Administrator directly or indirectly, require any State to require such a permit.

(2) Stormwater runoff from oil, gas, and mining operations

The Administrator shall not require a permit under this section, nor shall the Administrator directly or indirectly require any State to require a permit, for discharges of stormwater runoff from mining operations or oil and gas exploration, production, processing, or treatment operations or transmission facilities, composed entirely of flows which are from conveyances or systems of conveyances (including but not limited to pipes, conduits, ditches, and channels) used for collecting and conveying precipitation runoff and which are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct, or waste products located on the site of such operations.

(m) Additional pretreatment of conventional pollutants not required

To the extent a treatment works (as defined in section 1292 of this title) which is publicly owned is not meeting the requirements of a permit issued under this section for such treatment works as a result of inadequate design or operation of such treatment works, the Administrator, in issuing a permit under this section, shall not require pretreatment by a person introducing conventional pollutants identified pursuant to section 1314(a)(4) of this title into such treatment works other than pretreatment required to assure compliance with pretreatment standards under subsection (b)(8) of this section and section 1317(b)(1) of this title. Nothing in this subsection shall affect the Administrator's authority under sections 1317 and 1319 of this title, affect State and local authority under sections 1317(b)(4) and 1370 of this title, relieve such treatment works of its obligations to meet requirements established under this chapter, or otherwise preclude such works from pursuing whatever feasible options are available to meet its responsibility to comply with its permit under this section.

(n) Partial permit program

(1) State submission

The Governor of a State may submit under subsection (b) of this section a permit program for a portion of the discharges into the navigable waters in such State.

(2) Minimum coverage

A partial permit program under this subsection shall cover, at a minimum, administration of a major category of the discharges into the navigable waters of the State or a major component of the permit program required by subsection (b) of this section.

(3) Approval of major category partial permit programs

The Administrator may approve a partial permit program covering administration of a major category of discharges under this subsection if -

(A) such program represents a complete permit program and covers all of the discharges under the jurisdiction of a department or agency of the State; and

(B) the Administrator determines that the partial program represents a significant and identifiable part of the State program required by subsection (b) of this section.

(4) Approval of major component partial permit programs

The Administrator may approve under this subsection a partial and phased permit program covering administration of a major component (including discharge categories) of a State permit program required by subsection (b) of this section if -

(A) the Administrator determines that the partial program represents a significant and identifiable part of the State program required by subsection (b) of this section; and

(B) the State submits, and the Administrator approves, a plan for the State to assume administration by phases of the remainder of the State program required by subsection (b) of this section by a specified date not more than 5 years after submission of the partial program under this subsection and agrees to make all reasonable efforts to assume such administration by such date.

(o) Anti-backsliding

(1) General prohibition

In the case of effluent limitations established on the basis of subsection (a)(1)(B) of this section, a permit may not be renewed, reissued, or modified on the basis of effluent guidelines promulgated under section 1314(b) of this title subsequent to the original issuance of such permit, to contain effluent limitations which are less stringent than the comparable effluent limitations in the previous permit. In the case of effluent limitations established on the basis of section 1311(b)(1)(C) or section 1313(d) or (e) of this title, a permit may not be renewed, reissued, or modified to contain effluent limitations which are less stringent than the comparable effluent limitations in the previous permit except in compliance with section 1313(d)(4) of this title.

(2) Exceptions

A permit with respect to which paragraph (1) applies may be renewed, reissued, or modified to contain a less stringent effluent limitation applicable to a pollutant if -

(A) material and substantial alterations or additions to the permitted facility occurred after permit issuance which justify the application of a less stringent effluent limitation;

(B)(i) information is available which was not available at the time of permit issuance (other than revised regulations, guidance, or test methods) and which would have justified the application of a less stringent effluent limitation at the time of permit issuance; or

(ii) the Administrator determines that technical mistakes or mistaken interpretations of law were made in issuing the permit under subsection (a)(1)(B) of this section;

(C) a less stringent effluent limitation is necessary because of events over which the permittee has no control and for which there is no reasonably available remedy;

(D) the permittee has received a permit modification under section 1311(c), 1311(g), 1311(h), 1311(i), 1311(k), 1311(n), or 1326(a) of this title; or

(E) the permittee has installed the treatment facilities required to meet the effluent limitations in the previous permit and has properly operated and maintained the facilities but has nevertheless been unable to achieve the previous effluent limitations, in which case the limitations in the reviewed, reissued, or modified permit may reflect the level of pollutant control actually achieved (but shall not be less stringent than required by effluent guidelines in effect at the time of permit renewal, reissuance, or modification).

Subparagraph (B) shall not apply to any revised waste load allocations or any alternative grounds for translating water quality standards into effluent limitations, except where the cumulative effect of such revised allocations results in a decrease in the amount of pollutants discharged into the concerned waters, and such revised allocations are not the result of a discharger eliminating or substantially reducing its discharge of pollutants due to complying with the requirements of this chapter or for reasons otherwise unrelated to water quality.

(3) Limitations

In no event may a permit with respect to which paragraph (1) applies be renewed, reissued, or modified to contain an effluent limitation which is less stringent than required by effluent guidelines in effect at the time the permit is renewed, reissued, or modified. In no event may such a permit to discharge into waters be renewed, reissued, or modified to contain a less stringent effluent limitation if the implementation of such limitation would result in a violation of a water quality standard under section 1313 of this title applicable to such waters.

(p) Municipal and industrial stormwater discharges

(1) General rule

Prior to October 1, 1994, the Administrator or the State (in the case of a permit program approved under this section) shall not require a permit under this section for discharges composed entirely of stormwater.

(2) Exceptions

Paragraph (1) shall not apply with respect to the following stormwater discharges:

(A) A discharge with respect to which a permit has been issued under this section before February 4, 1987.

(B) A discharge associated with industrial activity.

(C) A discharge from a municipal separate storm sewer system serving a population of 250,000 or more.

(D) A discharge from a municipal separate storm sewer system serving a population of 100,000 or more but less than 250,000.

(E) A discharge for which the Administrator or the State, as the case may be, determines that the stormwater discharge contributes to a violation of a water quality standard or is a significant contributor of pollutants to waters of the United States.

(3) Permit requirements

(A) Industrial discharges

Permits for discharges associated with industrial activity shall meet all applicable provisions of this section and section 1311 of this title.

(B) Municipal discharge

Permits for discharges from municipal storm sewers -

(i) may be issued on a system- or jurisdiction-wide basis;

(ii) shall include a requirement to effectively prohibit non-stormwater discharges into the storm sewers; and

(iii) shall require controls to reduce the discharge of pollutants to the maximum extent practicable, including management practices, control techniques and system, design and engineering methods, and such other provisions as the Administrator or the State determines appropriate for the control of such pollutants.

(4) Permit application requirements

(A) Industrial and large municipal discharges

Not later than 2 years after February 4, 1987, the Administrator shall establish regulations setting forth the permit application requirements for stormwater discharges described in paragraphs (2)(B) and (2)(C). Applications for permits for such discharges shall be filed no later than 3 years after February 4, 1987. Not later than 4 years after February 4, 1987, the Administrator or the State, as the case may be, shall issue or deny each such permit. Any such permit shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the date of issuance of such permit.

(B) Other municipal discharges

Not later than 4 years after February 4, 1987, the Administrator shall establish regulations setting forth the permit application requirements for stormwater discharges described in paragraph (2)(D). Applications for permits for such discharges shall be filed no later than 5 years after February 4, 1987. Not later than 6 years after February 4, 1987, the Administrator or the State, as the case may be, shall issue or deny each such permit. Any such permit shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the date of issuance of such permit.

(5) Studies

The Administrator, in consultation with the States, shall conduct a study for the purposes of -

(A) identifying those stormwater discharges or classes of stormwater discharges for which permits are not required pursuant to paragraphs (1) and (2) of this subsection;

(B) determining, to the maximum extent practicable, the nature and extent of pollutants in such discharges; and

(C) establishing procedures and methods to control stormwater discharges to the extent necessary to mitigate impacts on water quality.

Not later than October 1, 1988, the Administrator shall submit to Congress a report on the results of the study described in subparagraphs (A) and (B). Not later than October 1, 1989, the Administrator shall submit to Congress a report on the results of the study described in subparagraph (C).

(6) Regulations

Not later than October 1, 1993, the Administrator, in consultation with State and local officials, shall issue regulations (based on the results of the studies conducted under paragraph (5)) which designate stormwater discharges, other than those discharges described in paragraph (2), to be regulated to protect water quality and shall establish a comprehensive program to regulate such designated sources. The program shall, at a minimum, (A) establish priorities, (B) establish requirements for State stormwater management programs, and (C) establish expeditious deadlines. The program may include performance standards, guidelines, guidance, and management practices and treatment requirements, as appropriate.

(q) Combined sewer overflows

(1) Requirement for permits, orders, and decrees

Each permit, order, or decree issued pursuant to this chapter after December 21, 2000, for a discharge from a municipal combined storm and sanitary sewer shall conform to the Combined Sewer Overflow Control Policy signed by the Administrator on April 11, 1994 (in this subsection referred to as the "CSO control policy").

(2) Water quality and designated use review guidance

Not later than July 31, 2001, and after providing notice and opportunity for public comment, the Administrator shall issue guidance to facilitate the conduct of water quality and designated use reviews for municipal combined sewer overflow receiving waters.

(3) Report

Not later than September 1, 2001, the Administrator shall transmit to Congress a report on the progress made by the Environmental Protection Agency, States, and municipalities in implementing and enforcing the CSO control policy.

(June 30, 1948, ch. 758, title IV, Sec. 402, as added Pub. L. 92-500, Sec. 2, Oct. 18, 1972, 86 Stat. 880; amended Pub. L. 95-217, Sec. 33(c), 50, 54(c)(1), 65, 66, Dec. 27, 1977, 91 Stat. 1577, 1586, 1591, 1599, 1600; Pub. L. 100-4, title IV, Sec. 401-404(a), 404(c), formerly 404(d), 405, Feb. 4, 1987, 101 Stat. 65-67, 69, renumbered Sec. 404(c), Pub. L. 104-66, title II, Sec. 2021(e)(2), Dec. 21, 1995, 109 Stat. 727; Pub. L. 102-580, title III, Sec. 364, Oct. 31, 1992, 106 Stat. 4862; Pub. L. 106-554, Sec. 1(a)(4) (div. B, title I, Sec. 112(a)), Dec. 21, 2000, 114 Stat. 2763, 2763A-224.)

AMENDMENTS

2000 - Subsec. (q). Pub. L. 106-554 added subsec. (q).

1992 - Subsec. (p)(1), (6). Pub. L. 102-580 substituted "October 1, 1994" for "October 1, 1992" in par. (1) and "October 1, 1993" for "October 1, 1992" in par. (6).

1987 - Subsec. (a)(1). Pub. L. 100-4, Sec. 404(c), inserted cl. (A) and (B) designations.

Subsec. (c)(1). Pub. L. 100-4, Sec. 403(b)(2), substituted "as to those discharges" for "as to those navigable waters".

Subsec. (c)(4). Pub. L. 100-4, Sec. 403(b)(1), added par. (4).

Subsec. (l). Pub. L. 100-4, Sec. 401, inserted "Limitation on permit requirement" as subsec. heading designated existing provisions as par. (1) and inserted par. heading, added par. (2), and aligned pars. (1) and (2).

Subsecs. (m) to (p). Pub. L. 100-4, Sec. 402, 403(a), 404(a), 405, added subsecs. (m) to (p).

1977 - Subsec. (a)(5). Pub. L. 95-217, Sec. 50, substituted "section 1314(i)(2)" for "section 1314(h)(2)".

Subsec. (b). Pub. L. 95-217, Sec. 50, substituted in provisions preceding par. (1) "subsection (i)(2) of section 1314" for "subsection (h)(2) of section 1314".

Subsec. (b)(8). Pub. L. 95-217, Sec. 54(c)(1), inserted reference to identification in terms of character and volume of pollutants of any significant source introducing pollutants subject to pretreatment standards under section 1317(b) of this title into treatment works and programs to assure compliance with pretreatment standards by each source.

Subsec. (c)(1), (2). Pub. L. 95-217, Sec. 50, substituted "section 1314(i)(2)" for "section 1314(h)(2)".

Subsec. (d)(2). Pub. L. 95-217, Sec. 65(b), inserted provision requiring that, whenever the Administrator objects to the issuance of a permit under subsec. (d)(2) of this section, the written objection contain a statement of the reasons for the objection and the effluent limitations and conditions which the permit would include if it were issued by the Administrator.

Subsec. (d)(4). Pub. L. 95-217, Sec. 65(a), added par. (4).

Subsec. (e). Pub. L. 95-217, Sec. 50, substituted "subsection (i)(2) of section 1314" for "subsection (h)(2) of section 1314".

Subsec. (h). Pub. L. 95-217, Sec. 66, substituted "where no State program is approved or where the Administrator determines pursuant to section 1319(a) of this title that a State with an approved program has not commenced appropriate enforcement action with respect to such permit," for "where no State program is approved,".

Subsec. (l). Pub. L. 95-217, Sec. 33(c), added subsec. (l).

TRANSFER OF FUNCTIONS

Enforcement functions of Administrator or other official of the Environmental Protection Agency under this section relating to compliance with national pollutant discharge elimination system permits with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas were transferred to the Federal Inspector, Office of Federal Inspector for the Alaska Natural Gas Transportation System, until the first anniversary of the date of initial operation of the Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, Sec. 102(a), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, effective July 1, 1979, set out in the Appendix to Title 5, Government Organization and Employees. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102-486, set out as an Abolition of Office of Federal Inspector note under section 719e of Title 15, Commerce and Trade.

STORMWATER PERMIT REQUIREMENTS

Pub. L. 102-240, title I, Sec. 1068, Dec. 18, 1991, 105 Stat. 2007, provided that:

"(a) General Rule. - Notwithstanding the requirements of sections 402(p)(2)(B), (C), and (D) of the Federal Water Pollution Control Act (33 U.S.C. 1342(p)(2)(B), (C), (D)), permit application deadlines for stormwater discharges associated with industrial activities from facilities that are owned or operated by a municipality shall be established by the Administrator of the Environmental Protection Agency (hereinafter in this section referred to as the 'Administrator') pursuant to the requirements of this section.

"(b) Permit Applications. -

"(1) Individual applications. - The Administrator shall require individual permit applications for discharges described in subsection (a) on or before October 1, 1992; except that any municipality that has participated in a timely part I group application for an industrial activity discharging stormwater that is denied such participation in a group application or for which a group application is denied shall not be required to submit an individual application until the 180th day following the date on which the denial is made.

"(2) Group applications. - With respect to group applications for permits for discharges described in subsection (a), the Administrator shall require -

"(A) part I applications on or before September 30, 1991, except that any municipality with a population of less than 250,000 shall not be required to submit a part I application before May 18, 1992; and

"(B) part II applications on or before October 1, 1992, except that any municipality with a population of less than 250,000 shall not be required to submit a part II application before May 17, 1993.

"(c) Municipalities With Less Than 100,000 Population. - The Administrator shall not require any municipality with a population of less than 100,000 to apply for or obtain a permit for any stormwater discharge associated with an industrial activity other than an airport, powerplant, or uncontrolled sanitary landfill owned or operated by such municipality before October 1, 1992, unless such permit is required by section 402(p)(2)(A) or (E) of the Federal Water Pollution Control Act (33 U.S.C. 1342(p)(2)(A), (E)).

"(d) Uncontrolled Sanitary Landfill Defined. - For the purposes of this section, the term 'uncontrolled sanitary landfill' means a landfill or open dump, whether in operation or closed, that does not meet the requirements for run-on and run-off controls established pursuant to subtitle D of the Solid Waste Disposal Act (42 U.S.C. 6941 et seq.).

"(e) Limitation on Statutory Construction. - Nothing in this section shall be construed to affect any application or permit requirement, including any deadline, to apply for or obtain a permit for stormwater discharges subject to section 402(p)(2)(A) or

KPSC Case No. 2006-00307
Commission Staff First Set Data Request
Order Dated August 24, 2006
Item No.1
Page 14 of 16

(E) of the Federal Water Pollution Control Act (33 U.S.C. 1342(p)(2)(A), (E)).

"(f) Regulations. - The Administrator shall issue final regulations with respect to general permits for stormwater discharges associated with industrial activity on or before February 1, 1992."

PHOSPHATE FERTILIZER EFFLUENT LIMITATION

Section 306(c) of Pub. L. 100-4 provided that:

"(1) Issuance of permit. - As soon as possible after the date of the enactment of this Act (Feb. 4, 1987), but not later than 180 days after such date of enactment, the Administrator shall issue permits under section 402(a)(1)(B) of the Federal Water Pollution Control Act (33 U.S.C. 1342(a)(1)(B)) with respect to facilities -

"(A) which were under construction on or before April 8, 1974, and

"(B) for which the Administrator is proposing to revise the applicability of the effluent limitation established under section 301(b) of such Act (33 U.S.C. 1311(b)) for phosphate subcategory of the fertilizer manufacturing point source category to exclude such facilities.

"(2) Limitations on statutory construction. - Nothing in this section (amending section 1311 of this title and enacting this note) shall be construed -

"(A) to require the Administrator to permit the discharge of gypsum or gypsum waste into the navigable waters,

"(B) to affect the procedures and standards applicable to the Administrator in issuing permits under section 402(a)(1)(B) of the Federal Water Pollution Control Act (33 U.S.C. 1342(a)(1)(B)), and

"(C) to affect the authority of any State to deny or condition certification under section 401 of such Act (33 U.S.C. 1341) with respect to the issuance of permits under section 402(a)(1)(B) of such Act."

LOG TRANSFER FACILITIES

Section 407 of Pub. L. 100-4 provided that:

"(a) Agreement. - The Administrator and Secretary of the Army shall enter into an agreement regarding coordination of permitting for log transfer facilities to designate a lead agency and to process permits required under sections 402 and 404 of the Federal Water Pollution Control Act (33 U.S.C. 1342, 1344) , where both such sections apply, for discharges associated with the construction and operation of log transfer facilities. The Administrator and Secretary are authorized to act in accordance with the terms of such agreement to assure that, to the maximum extent practicable, duplication, needless paperwork and delay in the issuance of permits, and inequitable enforcement between and among facilities in different States, shall be eliminated.

"(b) Applications and Permits Before October 22, 1985. - Where both of sections 402 and 404 of the Federal Water Pollution Control Act (33 U.S.C. 1342, 1344) apply, log transfer facilities which have received a permit under section 404 of such Act before October 22, 1985, shall not be required to submit a new application for a permit under section 402 of such Act. If the Administrator determines that the terms of a permit issued on or before October 22, 1985, under section 404 of such Act satisfies the applicable requirements of sections 301, 302, 306, 307, 308, and 403 of such Act (33 U.S.C. 1311, 1312, 1316, 1317, 1318, and 1343), a separate application for a permit under section 402 of such Act shall not thereafter be required. In any case where the Administrator demonstrates, after an opportunity for a hearing, that the terms of a permit issued on or before October 22, 1985, under section 404 of such Act do not satisfy the applicable requirements of sections 301, 302, 306, 307, 308, and 403 of such Act, modifications to the existing permit under section 404 of such Act to incorporate such applicable requirements shall be issued by the Administrator as an alternative to issuance of a separate new permit under section 402 of such Act.

"(c) Log Transfer Facility Defined. - For the purposes of this section, the term 'log transfer facility' means a facility which is constructed in whole or in part in waters of the United States and which is utilized for the purpose of transferring commercially harvested logs to or from a vessel or log raft, including the formation of a log raft."

ALLOWABLE DELAY IN MODIFYING EXISTING APPROVED STATE PERMIT PROGRAMS TO CONFORM TO 1977 AMENDMENT

Section 54(c)(2) of Pub. L. 95-217 provided that any State permit program approved under this section before Dec. 27, 1977, which required modification to conform to the amendment made by section 54(c)(1) of Pub. L. 95-217, which amended subsec. (b)(8) of this section, not be required to be modified before the end of the one year period which began on Dec. 27, 1977, unless in order to make the required modification a State must amend or enact a law in which case such modification not be required for such State before the end of the two year period which began on Dec. 27, 1977.

SECTION REFERRED TO IN OTHER SECTIONS

This section is referred to in sections 1251, 1283, 1284, 1285, 1288, 1301, 1311, 1314, 1317, 1318, 1319, 1321, 1323, 1328, 1341, 1343, 1344, 1345, 1365, 1369, 1371, 1373, 1377, 2104, 2803 of this title; title 42 sections 6903, 6924, 6925, 6939e, 9601.

Prev TOC Next

KPSC Case No. 2006-00307
Commission Staff First Set Data Request
Order Dated August 24, 2006
Item No.1
Page 16 of 16

Prev TOC Next

42 USC §6944. Criteria For Sanitary Landfills; Sanitary Landfills Required For All Disposal

(a) Criteria for sanitary landfills

Not later than one year after October 21, 1976, after consultation with the States, and after notice and public hearings, the Administrator shall promulgate regulations containing criteria for determining which facilities shall be classified as sanitary landfills and which shall be classified as open dumps within the meaning of this chapter. At a minimum, such criteria shall provide that a facility may be classified as a sanitary landfill and not an open dump only if there is no reasonable probability of adverse effects on health or the environment from disposal of solid waste at such facility. Such regulations may provide for the classification of the types of sanitary landfills.

(b) Disposal required to be in sanitary landfills, etc.

For purposes of complying with section 6943(2) (FOOTNOTE 1) of this title each State plan shall prohibit the establishment of open dumps and contain a requirement that disposal of all solid waste within the State shall be in compliance with such section 6943(2) (FOOTNOTE 1) of this title.

(FOOTNOTE 1) See References in Text note below.

(c) Effective date

The prohibition contained in subsection (b) of this section shall take effect on the date six months after the date of promulgation of regulations under subsection (a) of this section.

(Pub. L. 89-272, title II, Sec. 4004, as added Pub. L. 94-580, Sec. 2, Oct. 21, 1976, 90 Stat. 2815; amended Pub. L. 98-616, title III, Sec. 302(b), Nov. 8, 1984, 98 Stat. 3268.)

REFERENCES IN TEXT

Section 6943(2) of this title, referred to in subsec. (b), was redesignated section 6943(a)(2) of this title by Pub. L. 96-463, Sec. 5(b), Oct. 15, 1980, 94 Stat. 2056, and Pub. L. 96-482, Sec. 32(d)(2), Oct. 21, 1980, 94 Stat. 2353.

AMENDMENTS

1984 - Subsec. (c). Pub. L. 98-616 struck out "or on the date of approval of the State plan, whichever is later" at end.

TRANSFER OF FUNCTIONS

For transfer of certain enforcement functions of Administrator or other official of Environmental Protection Agency under this chapter to Federal Inspector, Office of Federal Inspector for the Alaska Natural Gas Transportation System, and subsequent transfer to Secretary of Energy, see note set out under section 6903 of this title.

SECTION REFERRED TO IN OTHER SECTIONS

This section is referred to in sections 6903, 6943, 6945, 6948, 6949a of this title; title 25 section 3902.

Kentucky Power Company

REQUEST

Refer to the McManus Testimony pages 8 and 9.

a. Describe the development of the multi-emissions compliance optimization ("MECO") model. This discussion should include, but not be limited to, when the Electric Power Research Institute and Charles Rivers Associates began developing the model, when the model was made available to utilities for use, and how extensively the MECO mode is used in the electric industry to model environmental compliance

b. Describe in detail the adjustments or modifications made to the MECO model to reflect American Electric Power Company's ("AEP's") system characteristics and individual plant input characteristics.

c. Explain in detail why Kentucky Power did not include the result of the MECO modeling as part of its application in this proceeding.

RESPONSE

a. As described on page 8 of the McManus Testimony, the model was developed as part of an Electric Power Research Institute (EPRI) tailored collaboration project. Charles Rivers Associates (CRA), a leading economic, and energy consulting firm, built the mathematical framework of the model. The development at CRA and EPRI began in the Spring of 2001. MECO was first used in 2003 at AEP. The model has been modified to reflect AEP's system characteristics and individual plant inputs.

The AEP MECO model is not available to the rest of the electric industry.

b. MECO was designed to receive input data at both the plant and company level. Thus no modifications were required to model structure; data was simply input reflecting our units and environmental constraints.

c. Kentucky Power did not include the result of the MECO modeling as part of its Application in this proceeding for two reasons. First, Kentucky Power's decision not to include the MECO modeling results is consistent with its past practice before the Commission. Historically, Kentucky Power has not included MECO modeling results in its Applications for approval of Environmental Compliance Plans and Environmental Surcharge Tariffs. Kentucky Power's Applications have only included the detailed economic justification for environmental projects undertaken within the Commonwealth of Kentucky. Second, the MECO modeling results are voluminous. Given that Kentucky Power is seeking recovery only for environmental projects undertaken outside the Commonwealth of Kentucky in this proceeding, and the voluminous nature of the results, Kentucky Power decided not to produce the results with its Application.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, Exhibit JMM-1.

a. Indicate which of the 44 projects listed on Exhibit JMM-1 were included in the MECO model.

b. Concerning the 44 projects included in Exhibit JMM-1, indicate when the MECO modeling was performed and indicate if the modeling has been updated subsequent to the selection of the 44 projects.

c. Provide all inputs AEP included in the MECO model. Provide the requested information for the MECO modeling that supported the 44 projects included in Exhibit JMM-1 and for any updated modeling subsequent to the selection of the 44 projects.

d. Provide the least cost compliance plan, compliance costs, and projected emissions generated by the MECO model. Provide the requested information for the MECO modeling that supported the 44 projects included in Exhibit JMM-1 and for any updated modeling subsequent to the selection of the 44 projects.

RESPONSE

a. All projects listed on Exhibit JMM-1, except Cardinal Catalyst Replacement, Sporn Landfill, Rockport Landfill, Mitchell Impoundment and Mitchell T/R set replacement were included in the MECO model. These projects were not included in the MECO results because they do not relate to Title IV Acid Rain/CAIR Program.

b. The MECO modeling was performed in January 2004, June 2004, and May 2005. MECO modeling is an on-going process, subsequent modeling runs will not affect the 44 projects. These projects and decisions have not changed since May of 2005.

c. Inputs from the January 2004, June 2004, May 2005, and April 2006 (See attached CD) runs have been provided in Attachment 3c.1_Inputs for Jan04Run, Attachment 3c.2_Inputs for Jun04Run, Attachment 3c.3_Inputs for May05Run, and Attachment 3c.4_Inputs for Apr06Run.

d. Update summaries from the January 2004, June 2004, and May 2005 runs have been provided as Attachment 3d.1_Jan05 MECO Summary, Attachment 3d.2_Jun04 MECO Summary, and Attachment 3d.3_May05 MECO Summary. The MECO summaries provide the least cost compliance plan, compliance costs, and project emissions.

For updated modeling results subsequent to the selection of the 44 projects, please see Attachment 3d.4_April 06 MECO update.

Additionally, Attachment 3d.5_KY MECO Plan & Cost has been provided to summarize the retrofit results within MECO for the four run dates and Attachment 3d.6, represents the emissions for the January 2004, June 2004, and May 2005 MECO runs.

Please see the attached CD for all attachments referenced in the above response.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

In addition to the results from the MECO modeling, provide the following information for each of the 44 projects listed in Exhibit JMM-1:

a. A list of the options or alternative technologies that addressed the environmental problem which were available at the time the project was selected.

b. Copies of internal AEP capital improvement documentation or similar documentation prepared for the project.

c. An explanation of why the items requested in parts (a) and (b) above were not included with Kentucky Power's application in this proceeding.

d. If the project was not included in the MECO modeling and internal AEP capital improvement document was not prepared for the project, explain in detail what analysis was performed for the project.

e. If the response to part (d) is no analysis was performed, explain in detail the reason(s) why no analysis was performed.

f. Copies of any regulatory commission approvals received for the project.

RESPONSE

a. Below are the alternatives that were considered for both SO2 and NOx compliance:

The SO2 Compliance Plan has evaluated several alternatives such as the procurement of SO2 allowances on the open market and/or fuel switching, but these alternatives will not provide the amount of SO2 emission reductions or allowances to ensure compliance of the AEP's coal-fired electrical generation fleet.

Alternatives to the SCR technology that were considered include buying needed NOx emissions allowances in the marketplace, Over-Fired Air (OFA), Water Injection, OFA & Water Injection, SNCR, OFA & PBR Fuel Blend, Amine Enhanced Fuel Lean Gas Reburn (AEFLGR), Gas Reburn, and PRB Fuel Blend. Reliance on an uncertain marketplace for NOx emissions allowances is an unacceptable compliance strategy and would place the Company and its ratepayers at an unacceptable risk of noncompliance. The alternatives to the application of SCR technology are, in some cases, not as cost effective as SCR and, in all cases, unable to achieve the reduction required to meet the applicable NOx requirements for the AEP system.

The remaining projects and their alternatives discussed below:

The FGD landfill and impoundment projects do not have options or alternatives. If the byproducts cannot be sold they must be landfilled. The FGD landfill projects will ensure that these long-term activities do not delay operation of the FGD projects. The development or expansion of the landfills are clearly the most economical solution for disposal of our gypsum and flyash waste.

Alternatives were not discussed for the Amos Unit 3 Precipitator Upgrade because this is an environmental and safety related project and as such, a typical cost/benefit analysis is not warranted. Elimination of the existing T/R sets at Mitchell Unit 1 and 2 reduces the environmental risk and the exposure of personnel to PCBs. Refurbishing the collecting fields improves particulate removal of the existing equipment and allows continuing compliance with the West Virginia particulate mass emission and opacity regulations.

b. In preparing the response to this data request it was discovered that the Total Net Investment on Exhibit JMM-1 page 2 of 2 should have read $2,031,785. However, due to the additional corrections as explained in the Company's response to Item No. 12, the revised total should be $2,030,083.

See attached capital improvements.
See Company's response to 8b for revised Exhibit JMM-1.

c. Kentucky Power did not include the items requested in parts (a) and (b) with its Application in this proceeding for two reasons. First, Kentucky Power's decision not to include this information is consistent with its past practice before the Commission. Historically, Kentucky Power has included this information in its Applications for approval of Environmental Compliance Plans and Environmental Surcharge Tariffs only in cases where Kentucky Power seeks the recovery of costs incurred for environmental projects undertaken within the Commonwealth of Kentucky. In cases such as this, where Kentucky Power is seeking the recovery of costs incurred exclusively for projects undertaken outside Kentucky, Kentucky Power has not included the information sought in parts (a) and (b) with its Applications. Second, the information is voluminous. Given that Kentucky Power is seeking recovery only for environmental projects undertaken outside the Commonwealth of Kentucky in this proceeding, and the voluminous nature of the information, Kentucky Power decided not to produce it with its Application.

d. The only project that would fit in this category would be the Rockport Unit 1 and Unit 2 landfill. At the time of filing, this project was identified in the AEP project forecast supplied by AEP Corporate Planning and Budgeting. Since the filing, an AEP capital improvement document has been completed. Please refer to the response in Item No. 4a for a copy of the capital improvements, including Rockport Landfill Expansion (CI # RKIMC0652).

e. Not applicable.

f. No project specific approvals were required from state ratemaking regulatory commissions. However, rate increases were granted by the Public Utilities Commission of Ohio in Case No. 04-169-EL-UNC based, among other things, upon the substantial capital cost requirements of Ohio Power Company for complying with environmental regulations. Rate recovery was granted by the Public Service Commission of West Virginia in Case No.05-1278-E-PC-02-42T that approved a settlement agreement which, among other things, provided for the recovery of the costs of Appalachian Power Company (APCO) complying with environmental regulations. Copies of the Public Utilities Commission of Ohio and Public Service Commission of West Virginia orders are attached. Rate recovery requests are also pending before the Virginia State Corporation Commission in Virginia Case No. PUE-2005-00056 and Case No. PUE-2006-00065 for APCO's environmental compliance costs, among other things.

WITNESS: John M McManus, Errol K Wagner

AEP®

CPP APPROVAL REQUISITION

Company: Ohio Power **Funding Project Number:** AM003FGDO

Authorization Type: X Capital Improvement ___ Original Version: ___
___ Lease Improvement X Revision Number: 04

Business Line: Generation

Location: Amos Unit 3

Project Title: AM U3 FGD Phase 3 – Engineering, Procurement and Construction

Brief Description: Final authorization to complete detailed engineering, design, procurement, environmental permitting, construction, and start-up activities required to retrofit a wet flue gas desulfurization system (FGDS) at Amos Unit 3 as part of Fleet SO2 Compliance Plan. This CI revision provides the necessary funding to complete the project previously authorized under Phase 1 and 2.

Project Dates:	Start:	Completion:	Authorization Needed by:
	06/15/04	12/31/08	06/30/06

Expenditure to be Authorized (fully loaded)	**Capital**	**Removal**	**Total Cost ($)**
Previously Approved Amount	$88,162,316	$0	$88,162,316
This Submission	$229,443,593	$0	$229,443,593
Total ($)	**$317,605,909**	**$0**	**$317,605,909**

Note: Amount to be authorized is the total amount

- Ohio Power

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP	Sigmon, W.	See Attached Document for Electronic Approval	
$10m ≤ amt < $20m	Executive Vice President	Powers, R.	See Attached Document for Electronic Approval	
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.	[signature]	6.14.06
amt ≥ $ 50m	Board of Directors	Keane, J	Secretary	
CP&B Review	Senior VP	Munczinski, R	[signature] for RBM	6/14/06

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group? ___ Yes X No

Nuclear Project Review Group? ___ Yes X No

Comments: ______

CPP APPROVAL REQUISITION

Project Expenditure Schedule

Year	2004	2005	2006	2007	2008	Future Years	Total ($)
Capital	$506,071	$22,076,333	$110,235,045	$145,541,907	$39,246,553		$317,605,909
Removal	$0	$0					$0
Amount to be Authorized	$506,071	$22,076,333	$110,235,045	$145,541,907	$39,246,553		$317,605,909
Assoc. O & M	$0	$0					$0

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

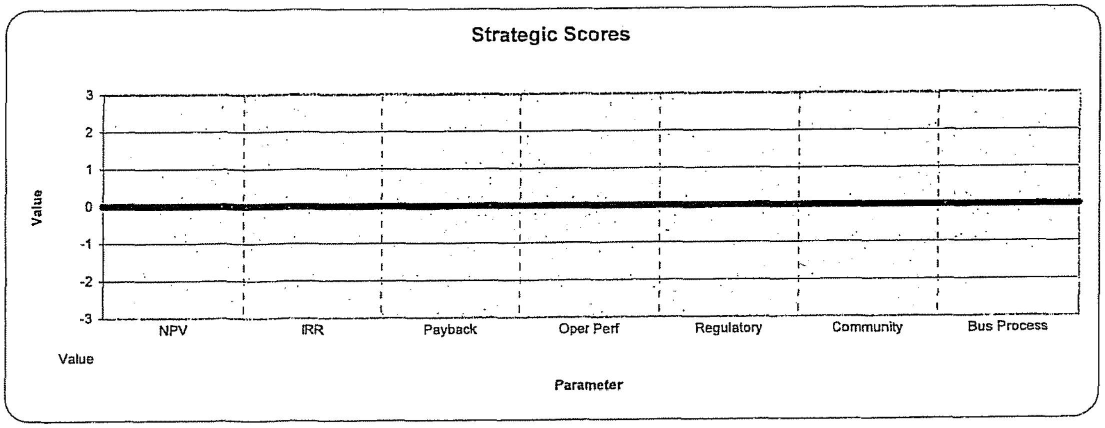
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: These results must match all background information

Scoring Summary

___ Discretionary X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

CPP APPROVAL REQUISITION

Component CIs

Service Date	CI Number	Description of Work	Est. Fully Loaded Capital Cost ($)	Est. Fully Loaded Removal Cost ($)
01/01/2008	000008933	FGD scope of work.	$230,862,650	
01/01/2008	AM003BALO	Balanced Draft Conversion	$26,628,748	
01/01/2008	AM003CONO	Controls Modernization	$9,431,870	
01/01/2008	AM003BMOO	Steam Generator Modifications.	$4,062,864	
01/01/2008	AM003SO3O	SO_3 Mitigation System	$9,382,118	2.95%
01/01/2008	AM000WWTO	AM Plant FGD Waste Water Treatment	$6,269,803	
01/01/2008	AM000COMO	AM Plant FGD Common Equipment	$27,139,275	
01/01/2008	AM003COAO	AM Plant Coal Blending Station	$3,828,581	
Total Cost ($)			**$317,605,909**	

526,279

Reason for Revision:

In order to meet a January 2008 in-service date, this Phase 3 CI revision is required to continue and complete detailed engineering, design, permitting, procurement, construction and start-up of the Amos Unit 3 WFGD system. Phase 3 is the final authorization phase of this project and requests funds for the completion of the FGD system and the following associated projects:

- Balanced Draft Conversion;
- SO_3 Mitigation System;
- Unit Controls Modernization;
- Steam Generator Additions;
- AM Plant Coal Blending Improvements;
- AM Plant Waste Water Treatment; and
- AM Plant FGD Common Equipment.

This project is being completed in three phases. The Phase 1 feasibility study was completed in March 2005. The Phase 2 engineering, design, procurement, and preliminary construction activities will be completed in June 2006. At the completion of Phase 2, engineering and design activities will be approximately 60% complete and approximately 70% of the contracting and procurement packages will have either been awarded or bid. Near the conclusion of Phase 2 and with much of this information available, the overall project cost estimate was updated based upon the engineering and procurement work completed during Phase 1 and Phase 2. This phased execution strategy greatly reduces overall project cost uncertainty and risk.

During Phase 3, the final environmental and building permits will be obtained to support construction and operation. Sargent and Lundy, the Architect-Engineer (A-E), will be released to complete engineering, design, and procurement activities under a not to exceed contract. Babcock and Wilcox (B&W), the FGD System supplier and Pullman, the chimney contractor, will be released to proceed with construction under a firm price contract. Additional contracts will be awarded to support the remaining balance of project civil, structural, mechanical and electrical construction work.

Preliminary site construction activities began in August 2005 including: relocation of railcar maintenance facilities, relocation of plant warehouse facilities and AEP construction offices, and relocation of underground and above ground mechanical and electrical facilities. The excavation and piling for the Unit 3 chimney and absorber building foundations began in January 2006 to support the chimney foundation pour which took place in May 2006. Both of these activities are to support the slip forming of the reinforced concrete chimney shell scheduled to begin in August 2006. Excavation and piling for the Units 1& 2 chimney foundation began in April 2006, and the excavation and piling for the Units 1, 2 and 3 common limestone slurry preparation building began in May 2006.

Phase 3 will fund all required AEPSC FGD project support including: project management, engineering, design, permitting, construction management and start-up support services through the scheduled in-service date and subsequent performance testing, reliability and acceptance testing in 2008.

Project Justification

The decision to retrofit wet flue gas desulfurization (WFGD) technology at Amos was made in the context of an AEP system wide environmental compliance analysis which identified scrubbing Amos Unit 3 as a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization (MECO) model, a unique mixed integer programming model that solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecasts, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytical 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 future multi-emissions legislations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Amos Units 1 & 2 scrubber decision was always a critical element of the least cost compliance plan.

In the March 2006 MECO run, AEP reanalyzed the compliance plan in light of the EPA Clean Air Interstate Rule (CAIR) and mercury rules and reached an identical conclusion. The Amos Unit 3 scrubber was again found to be an economic decision. In March 2006, updated capital costs and fuel pricing were entered into the model and Amos was again selected for scrubbing as part of AEP's least cost compliance plan.

In addition, under all the scenarios analyzed, the fuel and operating costs of Amos Unit 3 plus the scrubber investment (incremental capital) and additional O&M costs were well below current and projected future market prices for power, indicating that the investment in Amos Unit 3 was sound and robust relative to market alternatives.

Associated Environmental Operability and Reliability Work – Component CIs

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. The associated projects identified below are intended to provide greater operational flexibility and address overall reliability. The following projects are included in this Phase 3 funding request:

- **Balanced Draft Conversion** – The installation of FGD technology necessitates the installation of new induced draft fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balance draft condition). Converting to balance draft design concurrent with the WFGD retrofit enables the unit to burn lower cost high sulfur coal, provide a less hazardous work environment, and mitigate reduction in unit availability while reducing the potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - Portions of the SO_2 generated during coal combustion are oxidized to SO_3 in the steam generator and in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from the steam generator and SCR. Without additional controls, the stack SO_3 concentrations are expected to exceed 20 ppm when the SCR is not in operation and 40 ppm when the SCR is in operation. SO_3 concentrations of this magnitude in the flue gas that exit the stack form a secondary plume with a characteristic blue color and elevated visual opacity. To address this issue, dry sorbent injection technology will be installed to reduce the SO_3 emissions to 10 ppm or less.

- **Unit Controls Modernization** – The installation of WFGD technology will utilize a state of the art digital control system. Significant modernization of existing obsolete plant control systems will be required to enable integration of the new WFGD controls. The WFGD retrofit includes steam generator equipment additions for controlling boiler slag and balance draft operation. Significant modernization of the steam generator control system is needed to integrate this new equipment. Integration of new equipment controls, monitoring routines, and protection functions with the existing main control room operator interface must be accomplished in a manner that allows an operator to perform duties without confusion.

- **Steam Generator Additions** – The flexibility to burn higher sulfur coal, with its increased slagging potential and tube wall corrosion potential, requires retrofitting the steam generator with additional furnace slag control devices (water cannons and soot blowers), slag monitoring devices (high temperature camera and temperature instrumentation) and furnace tube wall corrosion protection (weld overlay) to operate satisfactorily and maintain reliability.

- **Coal Blending Improvements** - The installation of FGD technology improves the capabilities of the Amos units to burn higher sulfur content coal. This requires improvements to be made to the coal handling system currently in use at the station.

Conclusion

This funding request is for Ohio Power's portion of the Amos Unit 3 costs. Companion CPPs for Appalachian Power's portion of Unit 3 costs (AM003FGDA) and Appalachian Power's portion of the Unit 1 & 2 costs (AM012FGD0) are also in routing for approval.

Phase 3 funding is required to complete engineering, design, permitting, procurement, construction, and startup for the Amos Unit 3 WFGD system and associated projects.

The Amos Unit 3 WFGD system is scheduled to begin operation in January 2008.

Additional Information

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 economically provide the amount of SO_2 allowances required to support AEP's coal-fired electrical generation fleet.

Regulatory Issues

Existing regulations under Title IV of the Clean Air Act, as well as regulations recently issued by the U.S. EPA, will require AEP to significantly reduce emissions of SO_2 and NOx in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. The U.S. EPA's final Clean Air Interstate Rule (CAIR) will require additional SO_2 emission reductions beginning in 2010 and establishes annual NOx compliance requirements in 200,9 in addition to the ozone season requirements required under Title IV and CAIR.

In March 2005, U.S. EPA finalized a regulation for mercury emissions from coal-fired power plants. Under this program, if adopted by states in which AEP operates, mercury emissions will have to be reduced by approximately 1/3 by 2010. Mercury emission reductions of this magnitude are believed to be achievable with a combination of SCR and FGD control technology.

CPP APPROVAL REQUISITION

In addition to these regulations, the existing Title IV Acid Rain Control Program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

Background Information

In accordance with the fleet SO_2 compliance plan, the Amos FGD 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 will be limestone, and the technology will provide the operational flexibility to produce a gypsum byproduct. The FGD design criteria will maintain maximum fuel flexibility for the units. A wider range of coals, to include high sulfur coal, has been incorporated in the design criteria for the FGD.

The FGD design basis for these units includes 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 currently available technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

Associated / Future Projects

This funding request is for Ohio Power's portion of the Amos Unit 3 costs. Companion CPPs for Appalachian Power's portion of Unit 3 FGD costs (AM003FGDA) and Appalachian Power's portion of the Units 1 & 2 FGD costs (AM012FGD0) are also in routing for approval.

CI 000008354 has been approved for Appalachian Power's portion of work to perform engineering, design, permitting and construction of a future FGD landfill for Amos Plant. A similar CI is approved for Ohio Power's portion of work (000008355).

Project Contacts

Contact	Name	Telephone
Project Manager	Matthew P. Curtis	200-4712
Requisition Detail Provider	Lindsay E. Hart	200-3471

CPP APPROVAL REQUISITION

Company: Appalachian Power **Funding Project Number:** AM003FGDA

Authorization Type: X Capital Improvement ___ Lease Improvement

___ Original Version: ___
X Revision Number: 04

Business Line: Generation

Location: Amos Unit 3

Project Title: AM U3 FGD Phase 3 – Engineering, Procurement and Construction

Brief Description: Final authorization to complete detailed engineering, design, procurement, environmental permitting, construction, and start-up activities required to retrofit a wet flue gas desulfurization system (FGDS) at Amos Unit 3 as part of Fleet SO2 Compliance Plan. This CI revision provides the necessary funding to complete the project previously authorized under Phase 1 and 2.

Project Dates:	**Start:**	**Completion:**	**Authorization Needed by:**
	06/15/04	12/31/08	06/30/06

Expenditure to be Authorized (fully loaded)

	Capital	**Removal**	**Total Cost ($)**
Previously Approved Amount	$44,081,159	$0	$44,081,159
This Submission	$181,464,436	$0	$181,464,436
Total ($)	**$225,545,595**	**$0**	**$225,545,595**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	**Title**	**Approver**	**Signature**	**Date**
amt < $ 10m	Senior VP	Sigmon, W.	See Attached Document for Electronic Approval	
$10m ≤ amt < $20m	Executive Vice President	Powers, R.	See Attached Document for Electronic Approval	
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.	[signature]	6.14.06
amt ≥ $ 50m	Board of Directors	Keane, J	Secretary	
CP&B Review	Senior VP	Munczinski, R	John Torpey for RGM	6/14/06

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group?	___ Yes	X No
Nuclear Project Review Group?	___ Yes	X No

Comments: ___

CPP APPROVAL REQUISITION

Project Expenditure Schedule

Year	2004	2005	2006	2007	2008	Future Years	Total ($)
Capital	$249,259	$12,826,008	$78,574,274	$109,810,083	$24,085,971		$225,545,595
Removal	$0	$0					$0
Amount to be Authorized	$249,259	$12,826,008	$78,574,274	$109,810,083	$24,085,971		$225,545,595
Assoc. O & M	$0	$0					$0

Note: Operating & Maintenance dollars are assumed to be <u>in budget</u> or offset in the year spent.

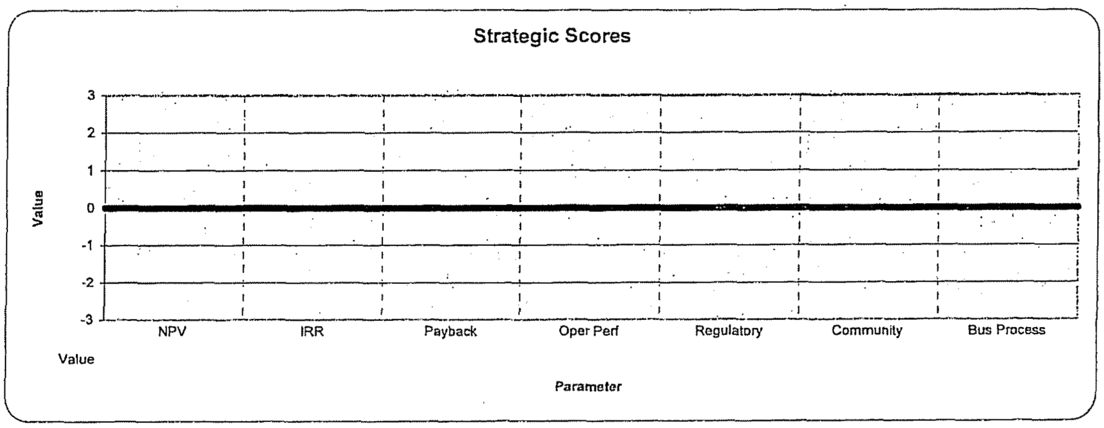
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: These results must match all background information

Scoring Summary

___ Discretionary   X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

CPP APPROVAL REQUISITION

Component CIs

Service Date	CI Number	Description of Work	Est. Fully Loaded Capital Cost ($)	Est. Fully Loaded Removal Cost ($)
01/01/2008	000008932	FGD scope of work.	$113,984,894	
01/01/2008	AM003BALA	Balanced Draft Conversion	$13,153,133	
01/01/2008	AM003CONA	Controls Modernization	$4,663,412	
01/01/2008	AM003BMOA	Steam Generator Modifications.	$2,006,189	
01/01/2008	AM003SO3A	SO_3 Mitigation System	$4,634,074	
01/01/2008	AM000WWTA	AM Plant FGD Waste Water Treatment	$14,671,622	
01/01/2008	AM000COMA	AM Plant FGD Common Equipment	$63,478,425	
01/01/2008	AM003COAA	AM Plant Coal Blending Station	$8,953,846	
Total Cost ($)			**$225,545,595**	

Reason for Revision:

In order to meet a January 2008 in-service date, this Phase 3 CI revision is required to continue and complete detailed engineering, design, permitting, procurement, construction and start-up of the Amos Unit 3 WFGD system. Phase 3 is the final authorization phase of this project and requests funds for the completion of the FGD system and the following associated projects:

- Balanced Draft Conversion;
- SO_3 Mitigation System;
- Unit Controls Modernization;
- Steam Generator Additions;
- AM Plant Coal Blending Improvements;
- AM Plant Waste Water Treatment; and
- AM Plant FGD Common Equipment.

This project is being completed in three phases. The Phase 1 feasibility study was completed in March 2005. The Phase 2 engineering, design, procurement, and preliminary construction activities will be completed in June 2006. At the completion of Phase 2, engineering and design activities will be approximately 60% complete and approximately 70% of the contracting and procurement packages will have either been awarded or bid. Near the conclusion of Phase 2 and with much of this information available, the overall project cost estimate was updated based upon the engineering and procurement work completed during Phase 1 and Phase 2. This phased execution strategy greatly reduces overall project cost uncertainty and risk.

During Phase 3, the final environmental and building permits will be obtained to support construction and operation. Sargent and Lundy, the Architect-Engineer (A-E), will be released to complete engineering, design, and procurement activities under a not to exceed contract. Babcock and Wilcox (B&W), the FGD System supplier and Pullman, the chimney contractor, will be released to proceed with construction under a firm price contract. Additional contracts will be awarded to support the remaining balance of project civil, structural, mechanical and electrical construction work.

Preliminary site construction activities began in August 2005 including: relocation of railcar maintenance facilities, relocation of plant warehouse facilities and AEP construction offices, and relocation of underground and above ground mechanical and electrical facilities. The excavation and piling for the Unit 3 chimney and absorber building foundations began in January 2006 to support the chimney foundation pour which took place in May 2006. Both of these activities are to support the slip forming of the reinforced concrete chimney shell scheduled to begin in August 2006. Excavation and piling for the Units 1& 2 chimney foundation began in April 2006, and the excavation and piling for the Units 1, 2 and 3 common limestone slurry preparation building began in May 2006.

Phase 3 will fund all required AEPSC FGD project support including: project management, engineering, design, permitting, construction management and start-up support services through the scheduled in-service date and subsequent performance testing, reliability and acceptance testing in 2008.

Project Justification

The decision to retrofit wet flue gas desulfurization (WFGD) technology at Amos was made in the context of an AEP system wide environmental compliance analysis which identified scrubbing Amos Unit 3 as a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization (MECO) model, a unique mixed integer programming model that solves for the least cost environmental compliance plan. The model considers power and emission allowance markets, load demand forecasts, emission allowance balances, emission control retrofit costs, new unit costs, unit emission rates, and unit operating costs. This proprietary model is a sophisticated analytical 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 future multi-emissions legislations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Amos Units 1 & 2 scrubber decision was always a critical element of the least cost compliance plan.

In the March 2006 MECO run, AEP reanalyzed the compliance plan in light of the EPA Clean Air Interstate Rule (CAIR) and mercury rules and reached an identical conclusion. The Amos Unit 3 scrubber was again found to be an economic decision. In March 2006, updated capital costs and fuel pricing were entered into the model and Amos was again selected for scrubbing as part of AEP's least cost compliance plan.

In addition, under all the scenarios analyzed, the fuel and operating costs of Amos Unit 3 plus the scrubber investment (incremental capital) and additional O&M costs were well below current and projected future market prices for power, indicating that the investment in Amos Unit 3 was sound and robust relative to market alternatives.

Associated Environmental Operability and Reliability Work – Component CIs

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. The associated projects identified below are intended to provide greater operational flexibility and address overall reliability. The following projects are included in this Phase 3 funding request:

- **Balanced Draft Conversion** – The installation of FGD technology necessitates the installation of new induced draft fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balance draft condition). Converting to balance draft design concurrent with the WFGD retrofit enables the unit to burn lower cost high sulfur coal, provide a less hazardous work environment, and mitigate reduction in unit availability while reducing the potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - Portions of the SO_2 generated during coal combustion are oxidized to SO_3 in the steam generator and in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from the steam generator and SCR. Without additional controls, the stack SO_3 concentrations are expected to exceed 20 ppm when the SCR is not in operation and 40 ppm when the SCR is in operation. SO_3 concentrations of this magnitude in the flue gas that exit the stack form a secondary plume with a characteristic blue color and elevated visual opacity.

To address this issue, dry sorbent injection technology will be installed to reduce the SO_3 emissions to 10 ppm or less.

- **Unit Controls Modernization** – The installation of WFGD technology will utilize a state of the art digital control system. Significant modernization of existing obsolete plant control systems will be required to enable integration of the new WFGD controls. The WFGD retrofit includes steam generator equipment additions for controlling boiler slag and balance draft operation. Significant modernization of the steam generator control system is needed to integrate this new equipment. Integration of new equipment controls, monitoring routines, and protection functions with the existing main control room operator interface must be accomplished in a manner that allows an operator to perform duties without confusion.

- **Steam Generator Additions** – The flexibility to burn higher sulfur coal, with its increased slagging potential and tube wall corrosion potential, requires retrofitting the steam generator with additional furnace slag control devices (water cannons and soot blowers), slag monitoring devices (high temperature camera and temperature instrumentation) and furnace tube wall corrosion protection (weld overlay) to operate satisfactorily and maintain reliability.

- **Coal Blending Improvements** - The installation of FGD technology improves the capabilities of the Amos units to burn higher sulfur content coal. This requires improvements to be made to the coal handling system currently in use at the station.

Conclusion

This funding request is for Appalachian Power's portion of the Amos Unit 3 costs. Companion CPPs for Ohio Power's portion of Unit 3 costs (AM003FGDO) and Appalachian Power's portion of the Unit 1 & 2 costs (AM012FGD0) are also in routing for approval.

Phase 3 funding is required to complete engineering, design, permitting, procurement, construction, and startup for the Amos Unit 3 WFGD system and associated projects.

The Amos Unit 3 WFGD system is scheduled to begin operation in January 2008.

Additional Information

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 economically provide the amount of SO_2 allowances required to support AEP's coal-fired electrical generation fleet.

Regulatory Issues

Existing regulations under Title IV of the Clean Air Act, as well as regulations recently issued by the U.S. EPA, will require AEP to significantly reduce emissions of SO_2 and NOx in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. The U.S. EPA's final Clean Air Interstate Rule (CAIR) will require additional SO_2 emission reductions beginning in 2010 and establishes annual NOx compliance requirements in 200,9 in addition to the ozone season requirements required under Title IV and CAIR.

In March 2005, U.S. EPA finalized a regulation for mercury emissions from coal-fired power plants. Under this program, if adopted by states in which AEP operates, mercury emissions will have to be reduced by approximately 1/3 by 2010. Mercury emission reductions of this magnitude are believed to be achievable with a combination of SCR and FGD control technology.

In addition to these regulations, the existing Title IV Acid Rain Control Program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

Background Information

In accordance with the fleet SO_2 compliance plan, the Amos FGD 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 will be limestone, and the technology will provide the operational flexibility to produce a gypsum byproduct. The FGD design criteria will maintain maximum fuel flexibility for the units. A wider range of coals, to include high sulfur coal, has been incorporated in the design criteria for the FGD.

The FGD design basis for these units includes 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 currently available technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

Associated / Future Projects

This funding request is for Appalachian Power's portion of the Amos Unit 3 costs. Companion CPPs for Ohio Power's portion of Unit 3 FGD costs (AM003FGDO) and Appalachian Power's portion of the Units 1 & 2 FGD costs (AM012FGD0) are also in routing for approval.

CI 000008354 has been approved for Appalachian Power's portion of work to perform engineering, design, permitting and construction of a future FGD landfill for Amos Plant. A similar CI is approved for Ohio Power's portion of work (000008355).

Project Contacts

Contact	Name	Telephone
Project Manager	Matthew P. Curtis	200-4712
Requisition Detail Provider	Lindsay E. Hart	200-3471

PROJECT APPROVAL REQUISITION

Company: Appalachian Power **Funding Project Number:** AMP000104

Authorization Type: X Capital Improvement ___ Original Version: ___
___ Lease Improvement X Revision Number: 1

Business Line: Generation

Location: Amos Unit 3

Project Title: ESP Upgrade and Balanced Draft Reinforcement

Brief Description: Perform detailed engineering, design and procurement of long lead items required to refurbish the Amos Unit 3 electrostatic precipitators and structurally reinforce it for balanced draft operation to assure compliance with opacity and particulate matter emission limits.

Project Dates:	Start:	Completion:	Authorization Needed by:
	11/01/2005	12/31/2007	N/A

Expenditure to be Authorized *(fully loaded)*

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$3,276,293	0	$3,276,293
This Submission	$1,168,725	0	$1,168,725
Total ($)	$4,445,018	0	$4,445,018

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W		
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.		
$20m < amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J.		

CP&B Review	Senior VP	Munczinski, R		

Budget Availability for this Authorization: X In Budget ___ Offset
Offset (source & amount):

Generation Only: Submission approved by Project Management Review Group? x Yes ___ No
Nuclear Project Review Group? ___ Yes ___ No

Comments: ______

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule (fully loaded)

Year	2005	2006	2007	2008	2009	Future Years	Total ($)
Capital	86	4,444,932					$4,445,018
Removal							0
Amount to be Authorized	86	4,444,932					$4,445,018
Assoc. O & M							

Financial Analysis Summary

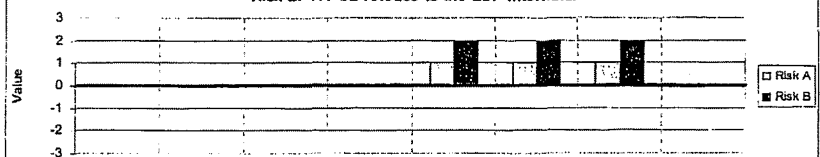
Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: This project was not justified by economics. It is justified on an environmental basis.

Scoring Summary

___ Discretionary   _x_ Mandated

Strategic Scores for:
Risk A. A PCB Release to the ESP Roof.
Risk B. A PCB release to the ESP Internals.



	NPV	IRR	Payback	Oper Perf	Regulatory	Safety	Community	Emp/Bus Process
Risk A	0	0	0	0	1	1	1	0
Risk B	0	0	0	0	2	2	2	0

Parameter

PROJECT APPROVAL REQUISITION

Risk Scores – Risk A. A PCB Release to the ESP Roof.				
		Consequence of not doing project		
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			F,S,T
	Rare/Remote	F,S,T	F,S,T	
		Risk Type Key: F = Financial, T = Technical, S = Sociopolitical		

Risk Scores – Risk B. A PCB Release to the ESP Internals.				
		Consequence of not doing project		
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		F,S,T	
	Likely/Possible	F,S,T		
	Rare/Remote			
		Risk Type Key: F = Financial, T = Technical, S = Sociopolitical		

This CI is being revised to increase the 2006 cash flow by $5,000,000 on a direct, total cost basis. Increasing the cash flow in 2006 allows the vendor to schedule material fabrication during slack periods in their shops, allowing them to decrease the material and project cost to us by $376,000.

This project is being completed in three phases. The Phase 1 feasibility study was completed in December 2005.

During Phase 2 an ESP equipment supplier will be released to proceed with the engineering, design and procurement of long lead materials required for ESP refurbishment and the structural reinforcement required for balanced draft operation. Also during Phase 2 the scope of the project will be finalized and the installation sequence and duration optimized

Construction work packages will be bid. These bids will be used to update the overall project cost estimate that will be reviewed with AEP Generation Management before proceeding with Phase 3 final construction. The phased approach will greatly reduce the project cost uncertainty.

Project Justification & Explanation of Scores

This is an environmental and safety related project and as such, the typical cost/benefit analysis is not warranted. Elimination of the existing T/R sets reduces the environmental risk and the exposure of personnel to PCBs. Refurbishing the collecting fields improves particulate removal of the existing equipment and allows continuing compliance with WVA particulate mass emission and opacity regulations

Reason for Revision

Spending an additional $5,000,000 on a direct, total cost basis in 2006 instead of 2007 reduces the Project cost $376,000.

Regulatory Issues

The work scope outlined in this CI addresses several regulatory issues.

- Safety and environmental issues regarding PCBs contained in the T/R sets at Amos Unit 3 will be eliminated
- Particulate capture will improve as a result of adding increased power and sectionalization to the ESP.

PROJECT APPROVAL REQUISITION

Associated Projects
This CI (AMP000104) funds APCo's share of Amos Unit 3. CI (AMP000488) funds OPCo's share of Amos Unit 3.

Project Contacts

Contact	Name	Telephone
Project Manager	P Scheckermann	200-3216
Requisition Detail Provider	P. Scheckermann	200-3216

AEP

PROJECT APPROVAL REQUISITION

Company: Ohio Power   Funding Project Number: AMP000488

Authorization Type: X Capital Improvement   ___ Original Version: ___
___ Lease Improvement   X Revision Number: 1

Business Line: Generation

Location: Amos Unit 3

Project Title: ESP Upgrade and Balanced Draft Reinforcement

Brief Description: Perform detailed engineering, design and procurement of long lead items required to refurbish the Amos Unit 3 electrostatic precipitators and structurally reinforce it for balanced draft operation to assure compliance with opacity and particulate matter emission limits.

Project Dates: Start: 11/01/2005   Completion: 12/31/2007   Authorization Needed by: N/A

Expenditure to be Authorized (fully loaded)	Capital	Removal	Total Cost ($)
Previously Approved Amount	$6,252,982	0	$6,252,982
This Submission	$2,666,807	0	$2,666,807
Total ($)	**$8,919,789**	**0**	**$8,919,789**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W.		
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J.		

The total cost on the original CI was $9,351,560. This was shown incorrectly as $9,529,275 on the revision, or an increase of $177,715. In the board package, this was included in the "Previously Approved" amount for APCo.

Munczinski, R ____________ ____________

X In Budget   ___ Offset

Project Management Review Group? x Yes ___ No
Nuclear Project Review Group? ___ Yes ___ No

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule (fully loaded)

Year	2005	2006	2007	2008	2009	Future Years	Total ($)
Capital	51	8,919,738					8,919,789
Removal							
Amount to be Authorized	51	8,919,738					8,919,789
Assoc. O & M							

Financial Analysis Summary

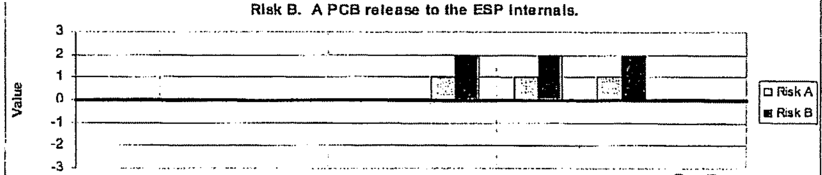
Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: This project was not justified by economics. It is justified on an environmental basis.

Scoring Summary

___ Discretionary   _x_ Mandated

Strategic Scores for:
Risk A. A PCB Release to the ESP Roof.
Risk B. A PCB release to the ESP Internals.



	NPV	IRR	Payback	Oper Perf	Regulatory	Safety	Community	Emp/Bus Process
Risk A	0	0	0	0	1	1	1	0
Risk B	0	0	0	0	2	2	2	0

Parameter

PROJECT APPROVAL REQUISITION

Risk Scores – Risk A. A PCB Release to the ESP Roof.				
		Consequence of not doing project		
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			F,S,T
	Rare/Remote	F,S,T	F,S,T	
Risk Type Key: F = Financial, T = Technical, S = Sociopolitical				

Risk Scores – Risk B. A PCB Release to the ESP Internals.				
		Consequence of not doing project		
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		F,S,T	
	Likely/Possible	F,S,T		
	Rare/Remote			
Risk Type Key: F = Financial, T = Technical, S = Sociopolitical				

This CI is being revised to increase the 2006 cash flow by $5,000,000 on a direct, total cost basis. Increasing the cash flow in 2006 allows the vendor to schedule material fabrication during slack periods in their shops, allowing them to decrease the material and project cost to us by $376,000.

This project is being completed in three phases. The Phase 1 feasibility study was completed in December 2005.

During Phase 2 an ESP equipment supplier will be released to proceed with the engineering, design and procurement of long lead materials required for ESP refurbishment and the structural reinforcement required for balanced draft operation. Also during Phase 2 the scope of the project will be finalized and the installation sequence and duration optimized.

Construction work packages will be bid. These bids will be used to update the overall project cost estimate that will be reviewed with AEP Generation Management before proceeding with Phase 3 final construction. The phased approach will greatly reduce the project cost uncertainty.

Project Justification & Explanation of Scores

This is an environmental and safety related project and as such, the typical cost/benefit analysis is not warranted. Elimination of the existing T/R sets reduces the environmental risk and the exposure of personnel to PCBs. Refurbishing the collecting fields improves particulate removal of the existing equipment and allows continuing compliance with WVA particulate mass emission and opacity regulations.

Reason for Revision

Spending an additional $5,000,000 on a direct, total cost basis in 2006 instead of 2007 reduces the project cost $376,000.

Regulatory Issues

The work scope outlined in this CI addresses several regulatory issues.

- Safety and environmental issues regarding PCBs contained in the T/R sets at Amos Unit 3 will be eliminated.
- Particulate capture will improve as a result of adding increased power and sectionalization to the ESP

PROJECT APPROVAL REQUISITION

Associated Projects
This CI (AMP000488) funds OPCo's share of Amos Unit 3. CI (AMP000104) funds APCo's share of Amos Unit 3.

Project Contacts

Contact	Name	Telephone
Project Manager	P. Scheckermann	200-3216
Requisition Detail Provider	P. Scheckermann	200-3216

AEP®

CPP APPROVAL REQUISITION

Ohio Power - Generation **Funding Project Number:** **CD001FGD0**

Authorization Type: x Capital Improvement ___ Original Version: 00
___ Lease Improvement X Revision Number: 03

Business Line: **Generation**

Location: **Cardinal Generating Plant**

Project Title: **CD U1 FGDS Phase III Engineering, Procurement and Construction**

Brief Description: **Final Authorization to complete detailed engineering, design, procurement, environmental permitting, construction and start-up of the Wet Flue Gas Desulfurization system for Unit 1 at Cardinal Plant in December 2007. This CI revision provides the necessary funding to complete the project previously authorized under Phase I& II.**

Project Dates:	**Start:**	**Completion:**	**Authorization Needed by:**
	08/25/2003	**07/1/2008**	**1/31/2006**

Expenditure to be Authorized (fully loaded)

	Capital	**Removal**	**Total Cost ($)**
Previously Approved Amount	$55,929,103	$0	$55,929,103
This Submission	255,864,187	0	255,864,187
Total ($)	**$311,793,290**	**$ 0**	**$311,793,290**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	**Title**	**Approver**	**Signature**	**Date**
amt < $ 10m	Senior VP	Sigmon, W.		
$10m ≤ amt < $20m	Executive Vice President	Powers, R.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J	Secretary	
CP&B Review	Senior VP	Munczinski, R		

Budget Availability for this Authorization: X In Budget ___ Offset
Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments: PMRG approval not required per Michael Isenberg

CPP APPROVAL REQUISITION

Project Expenditure Schedule

Year	2003	2004	2005	2006	2007	Future Years	Total ($)
Capital	$250,680	$5,276,064	$37,828,656	$101,948,107	$163,478,703	$3,011,080	$311,793,290
Removal	$0	$0	$0	$0	$0	$0	$0
Amount to be Authorized	$250,680	$5,276,064	$37,828,656	$101,948,107	$163,478,703	$3,011,080	$311,793,290
Assoc. O & M	$0	$0	$150,218	$0	$500,000	$0	$650,218

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

Financial Analysis Summary

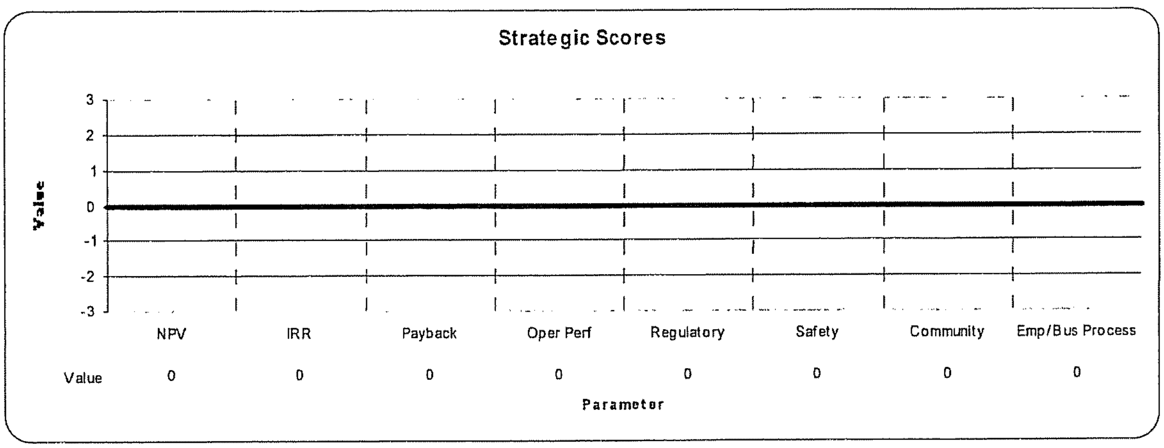
Reference "Business Case Supporting Emission Reduction Capital Needs" dated Jan 2004, by Chuck Zebula for Financial Analysis.

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: These results must match all background information

Scoring Summary

___ Discretionary X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			
Risk Type Key: F = Financial, T = Technical, S = Sociopolitical				

Please see Project Justification and Glossary for explanation of Scores

CPP APPROVAL REQUISITION

Component CIs

Service Date	CI Number	Description of Work	Est. Fully Loaded Capital Cost ($)	Est. Fully Loaded Removal Cost ($)
12/16/2007	000007231	FGD scope of work. This component CI was originally approved as a standalone CI (Revision 02) in the amount of $55,929,103.	$224,556,532	
12/16/2007	CD001CONO	Controls Modernization	$7,454,332	
12/16/2007	CD001BMOO	Boiler Modifications	$8,763,256	
12/16/2007	CD001BALO	Balanced Draft	$39,042,255	
12/16/2007	CD001FDFO	FD Fan Modifications	$2,228,312	
12/16/2007	CD001PURO	Purge Stream Water Treatment	$16,069,060	
12/16/2007	CD001SO3O	SO3 Mitigation	$9,165,967	
12/16/2007	CD001CATO	Catalyst Replacement	$4,513,576	
Total Cost ($)			**$311,793,290**	

Project Justification

- The decision to install Wet Flue Gas Desulfurization (WFGD) scrubber technology at Cardinal was made in the context of an AEP system wide environmental compliance analysis which identified that scrubbing Cardinal Units 1& 2 was a critical element in achieving the least cost compliance plan to meet current and future emission regulations. The analysis was conducted using the multi-emissions compliance optimization model (MECO), a unique mixed integer programming model which solves for the least cost environmental compliance plan. 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. This proprietary model is a sophisticated analytic tool that allows the company to systematically weigh costs and risks of a wide variety of options and allows simultaneous optimization across multi-emissions (SO_2, NO_x, mercury and CO_2).

In July 2003, the company analyzed a variety of potential environmental scenarios, including 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 under EPA's future regulatory initiatives for fine particulates, visibility and ozone attainment initiatives. In addition, potential multi-emissions regulations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Cardinal scrubber decision was always a critical element of the least cost compliance plan.

In the January 2005 MECO run, 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 Cardinal scrubber was again found to be an economic decision. In January 2005, updated capital costs and fuel pricing were entered into the model and Cardinal was again selected for scrubbing, as were retrofits necessary to burn low-cost high sulfur coal as part of AEP's least cost compliance plan.

In addition, under all the scenarios analyzed, fuel and operating costs of Cardinal 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 Cardinal was sound and robust relative to market alternatives.

Revision for Phase III (CPP CD001FGD0 Revision 3)

In order to meet the Cardinal FGD 2007 in-service date, this Phase III CPP is required to continue detailed engineering, design, scheduling, environmental planning, permitting, procurement, construction and start-up to obtain an operational WFGD system at Cardinal. Phase III is the final authorization phase and includes erection of WFGD and Balance of Plant (BOP) equipment and start-up.

Specifically, Phase III will build upon engineering and budgetary cost estimates from Phase II & Phase I and continue with detailed design including the shift from Open Spray Tower WFGD (OST) technology to Chiyoda Jet Bubbling Reactor WFGD (JBR) scrubber technology

Phase III will fully fund the selected Architect / Engineer (A/E) Black & Veatch (B&V), currently under contract for Cardinal Plant Units 1& 2 under a fixed price contract arrangement to provide Engineering, Procurement, Construction and Start-up (EPC) services for WFGD OEM & BOP scope.

Phase III will fully fund the selected chimney A/E (Pullman Power), currently under contract for Cardinal Units 1& 2 under a fixed price contract arrangement to provide Engineering, Procurement and Construction (EPC) services for the new 1000 ft. chimney required for WFGD.

Phase III will fund all required AEPSC FGD project support including; Project Management, Engineering, Design, Permitting, Construction and Start–up support services through the in-service date of December 16, 2007 and subsequent performance, reliability and acceptance testing in the 1st quarter of 2008.

Note: *Funding for Cardinal Units 1& 2 Landfill and Gypsum Transportation scope as well as funding for facilities required specifically for barge shipment of gypsum to the BPB wallboard facility will be included in separate CI funding requests.*

Associated Environmental Operability and Reliability Work – Component CIs

The AEP Fleet Compliance Plan to address emissions regulations in the most cost-effective manner relies on the efficient and reliable operation of the controlled Units. The associated projects identified below are intended to provide greater operational flexibility in this area and address overall reliability. The complexity of the associated projects and their interaction between WFGD and the existing SCR requires continuing review to optimize scope, costs and schedule. These projects (Component CIs) are consistently selected as a key part of the low cost compliance plan through MECO model analysis.

Steam generator additions to allow the use of the most economic high sulfur coal have been analyzed as a part of the WFGD project. The following associated projects are included in this Phase III funding request.

- **Balance Draft Conversion** –Installation of WFGD necessitates implementation of new fans to overcome additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balance draft design concurrent with a WFGD retrofit enables the unit to burn lower cost high sulfur coal, provides a less hazardous work environment, and mitigates reduction in unit availability while reducing the potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - A portion of SO_2 generated during coal combustion is oxidized to SO_3 in the steam generator and further oxidized in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from both the steam generator and SCR. Without additional controls, the stack SO_3 levels are projected to exceed the stack targeted control range SO_3 and could contribute to blue plume opacity in flue gas exiting the stack. Control of SO_3 stack emissions will require the application of two separate SO3 mitigation techniques/technologies. One of the required mitigation techniques will be replacement of the SCR catalyst with low SO_2 to SO_3 conversion catalyst to reduce the amount of SO_3 converted in the SCR. The second mitigation technology will require installation of a dry sorbent (trona or lime) injection system. This technology will inject sorbent into the flue gas upstream of the existing electrostatic precipitators (ESP) where SO_3 will react with the sorbent forming salts that are collected in the ESP.

- **Unit Controls Modernization** - The WFGD system employs a state of the art distributed control system. Significant modernization of existing obsolete plant control systems will be required to enable integration of new WFGD controls. In addition to providing a local control room for WFGD, all operator control functions required for systems modified by this project will be incorporated into a common control room console along with existing SCR control stations. Plant boiler control systems will be affected by the upgrade.

  WFGD retrofit includes new equipment for controlling boiler slag and balanced draft operation. Integration of new equipment controls, monitoring, and protection functions with the existing main control room operator interface must be accomplished in a manner that allows an operator to perform duties without confusion.

- **Steam Generator Modifications** –Flexibility to burn higher sulfur coal, with its increased slagging potential and tube wall corrosion potential requires retrofitting the boiler with additional equipment in order to maintain reliable operation. Modifications to the steam generator will include additional furnace slag control devices (water cannons and soot blowers), slag monitoring devices, (high temperature camera and temperature instrumentation) and furnace tube wall corrosion protection (weld overlay) to operate satisfactorily and maintain reliability.

- **Purge Stream Water Treatment** --Evaluation of expected WFGD purge stream water contents indicates that treatment for Total Suspended Solids (TSS) and PH will be required for environmental water quality compliance. Studies are in progress to finalize the design basis of the treatment facility that will be required to meet compliance standards. In order to support environmental permitting and an EPC execution schedule to meet the required operational date in December 2007, an estimated $14 million direct cost allowance is recommended to fund this portion of the work. This cost amount was determined from industry benchmarking and input from the AE. This portion of the project will be firmed up early in the second quarter of 2006.

- **FGD Project Bulk Power Feed-** Required 13.8 KV electrical power to operate the WFGD project will be supplied from the Cardinal Plant 138 KV switch yard. This power supply will be accomplished by the addition of (4) new 138KV to 13.8KV step-down transformers to be installed in the 138KV switchyard and (4) new 13.8 KV circuits running from the switchyard to a dead end structure located on Ohio Power property near WFGD facilities.

- **FD Fan Modifications** –Existing FD Fans may require modification to efficiently operate and accommodate changed operating conditions resulting from the addition of ID Fans required for FGD and Balanced Draft operation.

Regulatory Issues - Status November 2005

- Existing regulations under Title IV of the Clean Air Act, as well as regulations issued by the U.S. EPA in March, 2005, will require AEP to significantly reduce emissions of SO2 in the future. This will trigger the need to install additional emission control technology on selected plants in the fleet. U.S. EPA's, final Clean Air Interstate Rule will require additional SO2 emission reductions beginning in 2010 and establishes annual NOx compliance requirements in 2009 in addition to the ozone season requirements. In March 2005, U.S. EPA finalized a regulation for mercury emissions from coal-fired power plants. Under this program, if adopted by states in which AEP operates, mercury emissions will have to be reduced by approximately 1/3 by 2010. Mercury emission reductions can be achieved with a combination of SCR and FGD control technology. In addition to these regulations, the existing Title IV Acid Rain Control Program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO2 emission allowances in the market.

Alternatives Considered

- The SO2 Compliance Plan has evaluated several alternatives such as procurement of SO2 allowances on the open market and/or fuel switching, but these alternatives will not provide the amount of SO2 allowance required to support AEP's coal-fired electrical generation fleet.

Conclusion

- Phase III funding for engineering, design, procurement, permitting, construction and start-up is required to support the Cardinal Unit 1 WFGD program execution schedule and operation date of December 16, 2007.

- Approval of this Ohio Power Phase III CI for Cardinal Plant Unit 1 WFGD is recommended contingent upon Buckeye Power Company Board approval of the Cardinal Plant Unit 2 WFGD. This is necessary because the WFGD system design basis for each Cardinal unit relies on shared use and common ownership of various WFGD system components. (i.e.- chimney, barge facilities, limestone and gypsum material preparation, electrical power supply, material handling, water treatment, SO3 Mitigation)

- This strategy supports the construction of a WFGD at Cardinal Plant for operation in 2007.

Background Information

- In accordance with the fleet SO2 compliance plan, Cardinal 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 will be limestone, and the technology will provide the operational flexibility to produce a wall-board quality gypsum byproduct. The WFGD design criteria will maintain maximum fuel flexibility for burning high sulfur coal.

- The WFGD design basis for these units 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 Cardinal Unit 1 as requiring a WFGD in 2007 based on the current assumptions for SO_2 credit value and availability.

CPP APPROVAL REQUISITION

Associated Projects

- The following is a list of the joint plant projects for Cardinal Operating Company and Buckeye Power Company associated with the Ohio Power Company component CI's in this CPP:

CD Project	OP Project	BP Project	Project Description
000007110	000007231	000007230	CD U1 FGD
CD001CONM	CD001CONO	000007230	CD U1 Controls Modernization
CD001BMOD	CD001BMOO	000007230	CD U1 Boiler Modifications
CD001BALD	CD001BALO	000007230	CD U1 Balanced Draft
CD001FDFM	CD001FDFO	000007230	CD U1 FD Fan Modifications
CD001PURG	CD001PURO	000007230	CD U1 Purge Stream Water Treatment
CD001SO3M	CD001SO3O	000007230	CD U1 SO3 Mitigation
CD001CATA	CD001CATO	000007230	CD U1 Catalyst Replacement

Project Contacts

Contact	Name	Telephone
Project Manager	Dan Hummel	(614) 716-1725
Requisition Detail Provider	Dan Hummel	(614) 716-1725

Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 12/19/2005 04:51 PM

Plant	Unit	Funding Project #	Rev. #	Project Type
Gavin	0	000010779	1	Project

Project Title: GV Trona Final CI

Brief Description of Project (sufficient to determine that the project is Capital not O&M)

Complete Gavin Trona System: 1) Complete common storage facility including one additional silo and dehumidification equipment. 2) Install perforated plate rappers @ ESP Inlet and quench air pipes to mitigate agglomerationon both units. 3) Install additional turning vanes at air heater exit to reduce flow bias along bottom of duct on both units.

The first phase of this CI was for the procurement of long-lead time material. This revision will fund installation of the components.

Company	LEG-9 #	Originated
Ohio Power Co.	No	12/14/2005

Originator	Project Manager	CI Approval Required by
Michael H Huggett	Kurt S Huizing	12/30/2005

Originator Phone No.	Project Manager Phone No.	Amount to be Authorized
8-200-2092 614-716-2092	8-200-1723 614-716-1723	$9,996,582.00

Approved by PMRG Board:	Date Approved by PMRG Board:
Yes	11/18/2005

Will material become obsolete as a result of this CI? No

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Revised Budget (Direct Costs)	Prior Years	YR1 2005 ($x000)	YR2 2006 ($x000)	YR3 2007 ($x000)	YR4 2008 ($x000)	YR5+ 2009 ($x000)	Total
Additions - Plant	$0	$741	$7,980	$0	$0	$0	$8,721
Additions - ES	$0	$50	$764	$0	$0	$0	$814
Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Budget	$0	$791	$8,744	$0	$0	$0	$9,535
Associated O&M	$0	$0	$0	$0	$0	$0	$0

Project / CPP / Program Amount Being Authorized

Additions - Plant	$0	$741	$7,869	$0	$0	$0	$8,610
Additions - ES	$0	$50	$764	$0	$0	$0	$814
Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Costs to be Authorized	$0	$791	$8,633	$0	$0	$0	$9,424
Overheads	$0	$32	$345	$0	$0	$0	$377
AFUDC	$0	$7	$189	$0	$0	$0	$196
Amount Being Authorized	$0	$829	$9,167	$0	$0	$0	$9,997
Associated O&M	$0	$0	$0	$0	$0	$0	$0

For revisions to previously approved projects - Previous Amount Authorized

Additions - Plant	$0	$750	$0	$0	$0	$0	$750
Additions - ES	$0	$50	$0	$0	$0	$0	$50

Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Costs Previously Authorized	$0	$800	$0	$0	$0	$0	$800
Overheads	$0	$32	$0	$0	$0	$0	$32
AFUDC	$0	$40	$0	$0	$0	$0	$40
Amount Previously Authorized	$0	$872	$0	$0	$0	$0	$872
Associated O&M	$0	$0	$0	$0	$0	$0	$0

Incremental Amount to be Authorized (Calculated)

Additions - Plant	$0	($9)	$7,869	$0	$0	$0	$7,860
Additions - ES	$0	$0	$764	$0	$0	$0	$764
Removal - Plant	$0	$0	$0	$0	$0	$0	$0
Removal - ES	$0	$0	$0	$0	$0	$0	$0
Total Direct Costs Previously Authorized	$0	($9)	$8,633	$0	$0	$0	$8,624
Overheads	$0	$0	$345	$0	$0	$0	$345
AFUDC	$0	($33)	$189	$0	$0	$0	$156
Amount Difference	$0	($43)	$9,167	$0	$0	$0	$9,125
Associated O&M	$0	$0	$0	$0	$0	$0	$0

Ownership Unit Breakdown

Company	**Funding #**	**Prior** ($x000)	**YR1** ($x000)	**YR2** ($x000)	**YR3** ($x000)	**YR4** ($x000)	**YR5+** ($x000)	**Total** ($x000)
Ohio Power - Gen	000010779	$0	$829	$9,167	$0	$0	$0	$9,997

Mark A Gray	12/20/2005 10:52 AM EST
John M McManus	12/20/2005 12:01 PM EST
William L Sigmon	12/20/2005 05:20 PM EST

Comments

Michael J Simmons - 12/20/2005 09:33:42 AM
Mike Rencheck approved project request 12/20/2005

Attachments

000010779 Trona PRMG Presentation Rev 1.ppt   000010779 economics rev 1.xls   000010779 Justification Rev 1.xls

AEP

CPP APPROVAL REQUISITION

Company: Ohio Power Company

Funding Project Number: ML001FGD0

Authorization Type: Capital

X Original Version: 00
Revision Number:

Business Line: Generation

Location: Mitchell Generating Plant

Project Title: ML U1 WFGD/SCR Phase III Engineering, Procurement, and Construction

Brief Description: Final authorization to complete detailed engineering, design, procurement, construction, and start-up of a Wet Flue Gas Desulfurization and a Selective Catalytic Reduction system for Unit 1 by April 2007. This CI revision provides the necessary funding to complete the project previously authorized under Phases I & II.

Project Dates:	Start:	Completion:	Authorization Needed by:
	10/01/2001	06/30/2007	2/23/2005

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$73,048,582	$0	$73,048,582
This Submission	$371,316,707	$0	$371,316,707
Total ($)	**$444,365,298**	**$0**	**$444,365,298**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP	Sigmon, W.	[signature]	3/14/05
$ 10m ≤ amt < $20m	Executive VP/COO	Powers, R.	R. P. Pow	3/21/05
$20m ≤ amt < $50m	Chief Executive Officer	Morris, M. G.	[signature]	3/21/05
amt ≥ $ 50m	Board of Directors	Keane, J.	Secretary	
CP&B Review	Senior VP	Munczinski, R	John Torpey for RCM	3/18/05

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments:

IT Project Only: ___ $250,000 ≤ $1,000,000 submission approved by EVP or Delegated to SVP only? ___ Yes ___ No
___ > $1,000,000 submission approved by Office of Chairman? ___ Yes ___ No

CPP APPROVAL REQUISITION

Project Expenditure Schedule

Year	<2005	2005	2006	2007	2008	Future Years	Total ($)
Capital	$31,713,185	$136,763,381	$203,938,185	$71,950,538			$444,345,289
Removal	$0	$0	$0	$0			$0
Amount to be Authorized	$31,713,185	$136,763,381	$203,938,185	$71,950,538			$444,345,289
Assoc. O & M	$0	$0	$700,000	$0			$700,000

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

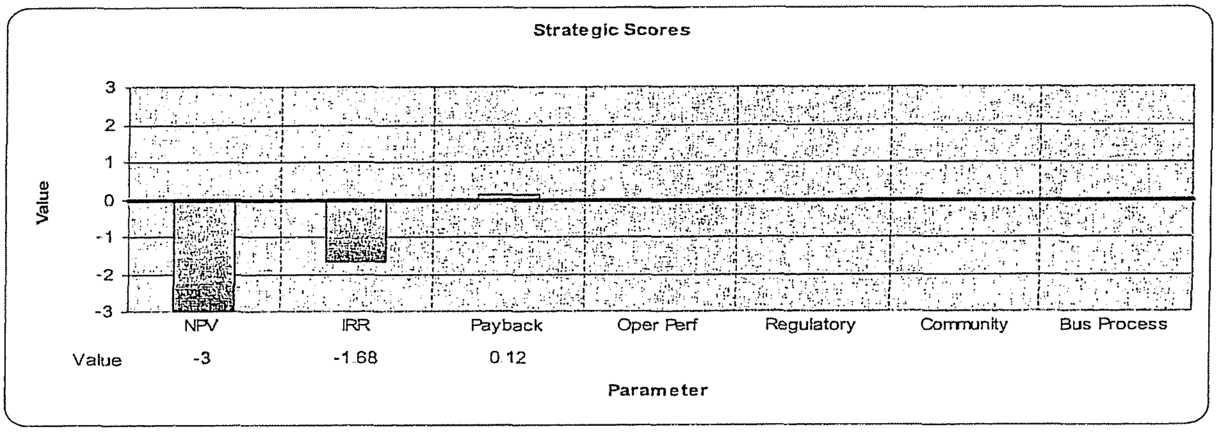
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	-1.0%	(150)	>15	7.9%

Note: These results must match all background information

Scoring Summary

___ Discretionary X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

CPP APPROVAL REQUISITION

Component CIs

Service Date	CI Number	Description of Work	Est. Fully Loaded Capital Cost ($)	Est. Fully Loaded Removal Cost ($)
04/01/2007	WSX115086	FGD/SCR scope of work. This component CI was originally approved as a standalone CI (Revision 03) in the amount of $73,048,582.	$369,248,323	
04/01/2007	ML001BALD	Balanced Draft Conversion	$24,116,897	
04/01/2007	ML001DCS0	Controls Modernization	$2,756,539	
04/01/2007	ML001BMOD	Steam Generator Modifications.	$10,139,130	
04/01/2007	ML001SO3M	SO_3 Mitigation System	$14,636,084	
04/01/2007	ML001PURG	Purge Stream Water Treatment System	$11,349,651	
04/01/2007	ML001COAL	Coal Blending Station	$12,121,665	
Total Cost ($)			$444,365,289	

- This Phase III CI final funding authorization covers expenditures in 2005, 2006 and 2007 to complete the Mitchell Unit 1 Wet Flue Gas Desulfurization (WFGD) and Selective Catalytic Reduction (SCR) projects including engineering, procurement, construction, and startup of the WFGD and SCR systems and all associated projects. The in-service date is scheduled for April 2007 with process testing and project close out completing June 2007.

- Site mobilization occurred in mid-August, 2004 to start excavation and relocation of underground interferences in preparation for excavation for the stack, absorber towers, and WFGD building foundations. Excavation for the stack foundation began in early October 2004 to support the stack shell erection commencing in March of 2005. Funding for site preparation, stack, and foundation contractors was provided by Phase II of this CI. All current authorization will be committed and/or spent by the end of February 2005.

Project Justification & Explanation of Scores

- The decision to install WFGD and SCR systems at Mitchell was made in the context of an AEP system wide environmental compliance analysis which identified that scrubbing Mitchell Unit 1 and installing a SCR system were critical elements in achieving the 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. 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. 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 (SO2, NOx, mercury and CO2).

  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 under EPA's future regulatory initiatives for fine particulates, visibility, and ozone attainment initiatives. In addition, potential multi-emissions regulations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Mitchell Plant WFGD/SCR decision was always a critical element 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 Mitchell Unit 1 WFGD and SCR were again found to be an economic decision.

- In January 2005, updated capital costs and fuel pricing were entered into the WFGD model and Mitchell Plant was again selected for scrubbing as were retrofits necessary to burn low-cost high sulfur coal as part of AEP's least cost compliance plan. In addition, under all the scenarios analyzed, the fuel and operating costs of Mitchell Unit 1 plus the WFGD 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 Mitchell was sound and robust relative to market alternatives.

- In order to meet the Mitchell Unit 1 WFGD/SCR 2007 in-service date, Phase III CI funding is required to continue and complete detailed engineering, design, scheduling, environmental planning, permitting, procurement, and construction to obtain operational WFGD and SCR systems at Mitchell. Phase III includes the erection of the WFGD, SCR and Balance of Plant (BOP) equipment and system startup.

- Specifically, Phase III will build upon the engineering and budgetary cost estimates from Phase II and continue with detailed engineering, design and construction. Construction labor Request for Quotation (RFQ) Packages were issued for competitive pricing and have become the basis of the Phase III requested labor funding for the WFGD project. A firm price for the SCR construction has been established, also through the use of competitive pricing.

- Phase III funds the selected A/E through completion of detailed engineering, design, and construction in 2007. Phase III also funds the selected WFGD and SCR OEMs to continue design and equipment selection, to support the construction and in-service schedule. Funding for Phase III also supports internal AEPSC engineering, design, air permitting efforts, project management and construction services through completion of the project.

Associated Environmental Operability and Reliability Work

The AEP Fleet Compliance Plan, to address emissions regulations in the most cost-effective manner, relies on the efficient and reliable operation of the controlled Units. The associated projects identified below are intended to provide greater operational flexibility in this area and addressing overall reliability. The complexity of the associated projects and their interaction between the WFGD and the SCR requires continuing review to optimize scope, costs and schedule. These projects are consistently selected as a key part of the low cost compliance plan through MECO model analysis.

Steam generator additions to allow the use of the most economic high sulfur coal have been analyzed as a part of the WFGD project. The following associated projects are included in Phase III.

- **Balance Draft Conversion** – The installation of WFGD necessitates the implementation of new fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balance draft design concurrent with a WFGD retrofit enables the Unit to combust high sulfur lower cost coal, consistently provides a less hazardous work environment, mitigates reduction in unit availability and reduces potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - A portion of the SO_2 generated during coal combustion is oxidized to SO_3 in the steam generator and further oxidized in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from both the steam generator and SCR. Without additional controls, the stack SO_3 levels are projected to exceed the stack targeted control range and could contribute to a blue plume opacity in the flue gas exiting the stack. The installation of a magnesium hydroxide slurry injection system into the upper furnace of the steam generator will reduce SO_3 exiting the boiler. The SCR will be designed to utilize low SO_2 to SO_3

conversion rate catalyst to minimize the amount of SO_3 converted in the SCR. The remaining SO_3 levels will be reduced to the control range via use of the existing ammonia injection system.

- **Unit Controls Modernization** – The installation of WFGD and SCR technologies will utilize a state of the art control system. This new, modern DCS system will be integrated into the existing unit controls, which will be incrementally modernized so as to make this work feasible. "Stand-alone" controls for the WFGD and SCR are not desirable.

- **Fuel Blending Capabilities** – On-site blending capability adds significant flexibility for the procurement of the most economic fuel. The economies of burning high sulfur coal have been analyzed as part of the WFGD project and are supported by the economic models. Mitchell plant has the tunnel and chute capacity and a radial stacker that will accommodate a blending operation. There are conveyors that would need to be added and/or upgraded to allow blending.

- **Steam Generator Additions** – Building on the fuel flexibility benefits, for Mitchell Plant to combust coals with sulfur contents as high as 4.5#/MBtu, the steam generator will require some changes, including installation of a new rearwall arch, additional furnace slag control devices (water cannons and/or blowers), furnace overlay to mitigate increased furnace corrosion, and boiler instrumentation upgrades.

- **Riverwater Makeup Pump Upgrades** - The water demands of the WFGD and SCR systems exceed the existing capacity of the riverwater makeup system. Review of various options to increase system capacity has determined that the most economic approach is to replace the existing pumps and motors with higher flow capacity pumps/motors. This will assure reliable water supply for plant needs as well as the WFGD and SCR.

- **Purge Stream Water Treatment** -- Initial evaluation of the potential purge stream water contents indicates that treatment may be required. Further studies are in progress to determine the extent of treatment if any, which may be required. In order to maintain the current schedule, a preliminary estimate of $20 million is allocated to fund this portion of the work. This number was determined from benchmarking the industry and input from the AE and will be accurately determined late in the second quarter of 2005.

Conclusion

- Phase III funding for engineering, design, procurement, construction, and start-up is required to support the WFGD and SCR schedule.

- This strategy supports the construction of WFGD and SCR systems at Mitchell Unit 1 for operation April 2007.

Additional Information

Regulatory Issues

- Existing regulations under Title IV of the Clean Air Act, as well as regulations currently under development by the U.S. EPA, along with other alternatives to the Clean Air Act being considered by Congress such as Clear Skies and the Carper Bill, will require AEP to reduce emissions of SO_2 in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. U.S. EPA proposed in December 2003 regulation of interstate air quality that, if promulgated, will require significant additional SO_2 and NO_x emission reductions beginning in 2010. U.S. EPA also proposed in December 2003 regulation of mercury emissions from coal-fired power plants. Mercury emission reductions can be achieved with a combined SCR and WFGD system. In addition to these proposed regulations, the existing Title IV acid rain control program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

CPP 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.

- Alternatives to the SCR technology that were considered include buying needed NOx emissions allowances in the marketplace, Over-Fired Air (OFA), Water Injection, OFA & Water Injection, SNCR, OFA & PRB Fuel Blend, AEFLGR, Gas Reburn, and PRB Fuel Blend. Reliance on an uncertain marketplace for NOx emissions allowances is an unacceptable compliance strategy and would place the Company and its ratepayers at an unacceptable risk of noncompliance. The alternatives to the application of SCR technology are, in some cases, not as cost effective as SCR and, in all cases, unable to achieve the reduction required at Mitchell to meet the applicable NOx requirements for the AEP System.

Background Information

- 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 will be limestone, and the technology will provide the operational flexibility to produce a wall-board quality gypsum byproduct. The WFGD design criteria provide maximum fuel flexibility by allowing for the burning of high sulfur coal.

- The WFGD design basis for this unit includes 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 emerging technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

- The SCR system will be designed for a 90% NOx removal rate with an allowable maximum ammonia slip of 2 ppmv (at 3% O_2) and a design catalyst life that minimizes the life cycle costs. A urea to ammonia conversion system will be used to supply the SCR reactors with reagent.

Project Contacts

Contact	Name	Telephone
Project Manager	Edward V. Gilabert – FGD Jerry L. Johnson - SCR	(614) 716-1765 (614) 716-3437
Requisition Detail Provider	Edward V. Gilabert	(614) 716-1765

CPP APPROVAL REQUISITION

Company: Ohio Power Company

Funding Project Number: ML002FGD0

Authorization Type: Capital

X Original Version: 00
Revision Number:

Business Line: Generation

Location: Mitchell Generating Plant

Project Title: ML U2 WFGD/SCR Phase III Engineering, Procurement, and Construction

Brief Description: Final authorization to complete detailed engineering, design, procurement, construction, and start-up of a Wet Flue Gas Desulfurization and a Selective Catalytic Reduction system for Unit 2 by December 2006. This CI revision provides the necessary funding to complete the project previously authorized under Phases I & II.

Project Dates:	Start:	Completion:	Authorization Needed by:
	10/01/2001	06/30/2007	2/23/2005

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$73,561,953	$0	$73,561,953
This Submission	$364,032,565	$0	$364,032,565
Total ($)	**$437,594,518**	**$0**	**$437,594,518**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP	Sigmon, W.	[signature]	3/14/05
$ 10m ≤ amt < $20m	Executive VP/COO	Powers, R.	[signature]	3/21/05
$20m ≤ amt < $50m	Chief Executive Officer	Morris, M. G.	[signature]	3/22/05
amt ≥ $ 50m	Board of Directors	Keane, J.	Secretary	

CP&B Review	Senior VP	Munczinski, R.	John Corpey for REM	3/17/05

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments:

IT Project Only: ___ $250,000 ≤ $1,000,000 submission approved by EVP or Delegated to SVP only? ___ Yes ___ No
___ > $1,000,000 submission approved by Office of Chairman? ___ Yes ___ No

CPP APPROVAL REQUISITION

Project Expenditure Schedule

Year	<2005	2005	2006	2007	2008	Future Years	Total ($)
Capital	$31,157,834	$148,081,544	$213,382,902	$44,972,238			$437,594,518
Removal	$0	$0	$0	$0			$0
Amount to be Authorized	$31,157,834	$148,081,544	$213,382,902	$44,972,238			$437,594,518
Assoc. O & M	$0	$0	$700,000	$0			$700,000

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

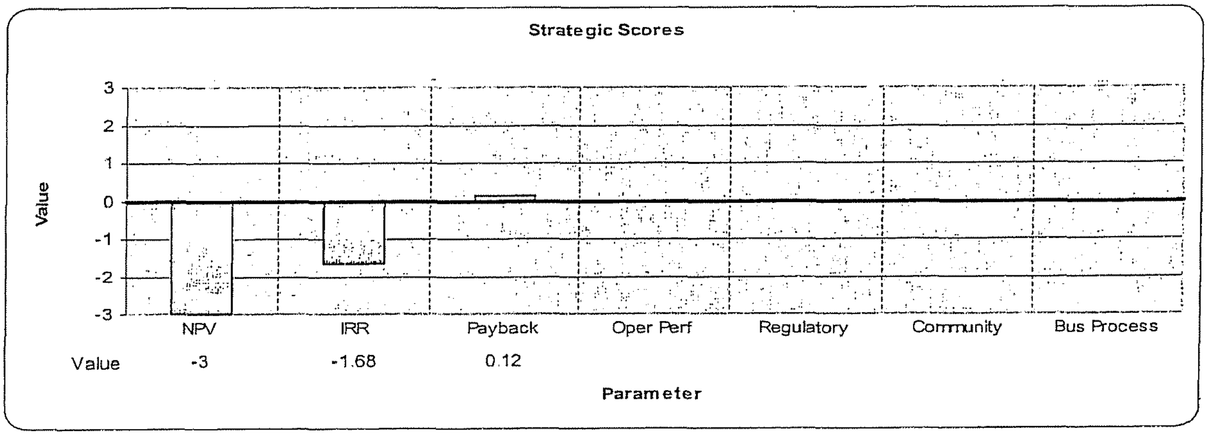
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	-1.0%	(150)	>15	7.9%

Note: These results must match all background information

Scoring Summary

___ Discretionary X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

Component CIs

Service Date	CI Number	Description of Work	Est. Fully Loaded Capital Cost ($)	Est. Fully Loaded Removal Cost ($)
12/31/2006	WSX115137	FGD/SCR scope of work. This component CI was originally approved as a standalone CI (Revision 03) in the amount of $73,561,953.	$362,984,414	
12/31/2006	ML002BALD	Balanced Draft Conversion	$23,843,429	
12/31/2006	ML002DCS0	Controls Modernization	$2,953,086	
12/31/2006	ML002BMOD	Steam Generator Modifications.	$10,014,620	
12/31/2006	ML002SO3M	SO_3 Mitigation System	$14,470,122	
12/31/2006	ML002PURG	Purge Stream Water Treatment System	$11,344,634	
12/31/2006	ML002COAL	Coal Blending Station	$11,984,214	
Total Cost ($)			**$437,594,518**	

- This Phase III CI final funding authorization covers expenditures in 2005, 2006 and 2007 to complete the Mitchell Unit 2 Wet Flue Gas Desulfurization (WFGD) and Selective Catalytic Reduction (SCR) projects including engineering, procurement, construction, and startup of the WFGD and SCR systems and all associated projects. The in-service date is scheduled for December 2006 with process testing and project close out completing June 2007.

- Site mobilization occurred in mid-August, 2004 to start excavation and relocation of underground interferences in preparation for excavation for the stack, absorber towers, and WFGD building foundations. Excavation for the stack foundation began in early October 2004 to support the stack shell erection commencing in March of 2005. Funding for site preparation, stack, and foundation contractors was provided by Phase II of this CI. *All current authorization will be* committed and/or spent by the end of February 2005.

Project Justification & Explanation of Scores

- The decision to install WFGD and SCR systems at Mitchell was made in the context of an AEP system wide environmental compliance analysis which identified that scrubbing Mitchell Unit 2 and installing a SCR system were critical elements in achieving the 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. 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. 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 (SO2, NOx, mercury and CO2).

  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 under EPA's future regulatory initiatives for fine particulates, visibility, and ozone attainment initiatives. In addition, potential multi-emissions regulations such as Clear Skies and the Carper bill were evaluated. The analysis indicated that under all the scenarios and related sensitivity analyses that the Mitchell Plant WFGD/SCR decision was always a critical element 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 Mitchell Unit 2 WFGD and SCR were again found to be an economic decision.

- In January 2005, updated capital costs and fuel pricing were entered into the WFGD model and Mitchell Plant was again selected for scrubbing as were retrofits necessary to burn low-cost high sulfur coal as part of AEP's least cost compliance plan. In addition, under all the scenarios analyzed, the fuel and operating costs of Mitchell Unit 2 plus the WFGD 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 Mitchell was sound and robust relative to market alternatives.

- In order to meet the Mitchell Unit 2 WFGD/SCR 2006 in-service date, Phase III CI funding is required to continue and complete detailed engineering, design, scheduling, environmental planning, permitting, procurement, and construction to obtain operational WFGD and SCR systems at Mitchell. Phase III includes the erection of the WFGD, SCR and Balance of Plant (BOP) equipment and system startup.

- Specifically, Phase III will build upon the engineering and budgetary cost estimates from Phase II and continue with detailed engineering, design and construction. Construction labor Request for Quotation (RFQ) Packages were issued for competitive pricing and have become the basis of the Phase III requested labor funding for the WFGD project. A firm price for the SCR construction has been established, also through the use of competitive pricing.

- Phase III funds the selected A/E through completion of detailed engineering, design, and construction in 2007. Phase III also funds the selected WFGD and SCR OEMs to continue design and equipment selection, to support the construction and in-service schedule. Funding for Phase III also supports internal AEPSC engineering, design, air permitting efforts, project management and construction services through completion of the project.

Associated Environmental Operability and Reliability Work

The AEP Fleet Compliance Plan, to address emissions regulations in the most cost-effective manner, relies on the efficient and reliable operation of the controlled Units. The associated projects identified below are intended to provide greater operational flexibility in this area and addressing overall reliability. The complexity of the associated projects and their interaction between the WFGD and the SCR requires continuing review to optimize scope, costs and schedule. These projects are consistently selected as a key part of the low cost compliance plan through MECO model analysis.

Steam generator additions to allow the use of the most economic high sulfur coal have been analyzed as a part of the WFGD project. The following associated projects are included in Phase III.

- **Balance Draft Conversion** – The installation of WFGD necessitates the implementation of new fans to overcome the additional system pressure drop (resistance). This provides the opportunity to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balance draft design concurrent with a WFGD retrofit enables the Unit to combust high sulfur lower cost coal, consistently provides a less hazardous work environment, mitigates reduction in unit availability and reduces potential for fugitive emissions to the environment.

- **SO_3 Mitigation System** - A portion of the SO_2 generated during coal combustion is oxidized to SO_3 in the steam generator and further oxidized in the SCR. Burning higher sulfur coals potentially increases the quantity of resultant SO_3 from both the steam generator and SCR. Without additional controls, the stack SO_3 levels are projected to exceed the stack targeted control range and could contribute to a blue plume opacity in the flue gas exiting the stack. The installation of a magnesium hydroxide slurry injection system into the upper furnace of the steam generator will reduce SO_3 exiting the boiler. The SCR will be designed to utilize low SO_2 to SO_3

conversion rate catalyst to minimize the amount of SO_3 converted in the SCR. The remaining SO_3 levels will be reduced to the control range via use of the existing ammonia injection system.

- **Unit Controls Modernization** – The installation of WFGD and SCR technologies will utilize a state of the art control system. This new, modern DCS system will be integrated into the existing unit controls, which will be incrementally modernized so as to make this work feasible. "Stand-alone" controls for the WFGD and SCR are not desirable.

- **Fuel Blending Capabilities** – On-site blending capability adds significant flexibility for the procurement of the most economic fuel. The economies of burning high sulfur coal have been analyzed as part of the WFGD project and are supported by the economic models. Mitchell plant has the tunnel and chute capacity and a radial stacker that will accommodate a blending operation. There are conveyors that would need to be added and/or upgraded to allow blending.

- **Steam Generator Additions** – Building on the fuel flexibility benefits, for Mitchell Plant to combust coals with sulfur contents as high as 4.5#/MBtu, the steam generator will require some changes, including installation of a new rearwall arch, additional furnace slag control devices (water cannons and/or blowers), furnace overlay to mitigate increased furnace corrosion, and boiler instrumentation upgrades.

- **Riverwater Makeup Pump Upgrades** - The water demands of the WFGD and SCR systems exceed the existing capacity of the riverwater makeup system. Review of various options to increase system capacity has determined that the most economic approach is to replace the existing pumps and motors with higher flow capacity pumps/motors. This will assure reliable water supply for plant needs as well as the WFGD and SCR.

- **Purge Stream Water Treatment** – Initial evaluation of the potential purge stream water contents indicates that treatment may be required. Further studies are in progress to determine the extent of treatment if any, which may be required. In order to maintain the current schedule, a preliminary estimate of $20 million is allocated to fund this portion of the work. This number was determined from benchmarking the industry and input from the AE and will be accurately determined late in the second quarter of 2005.

Conclusion

- Phase III funding for engineering, design, procurement, construction, and start-up is required to support the WFGD and SCR schedule.

- This strategy supports the construction of WFGD and SCR systems at Mitchell Unit 2 for operation December 2006.

Additional Information

Regulatory Issues

- Existing regulations under Title IV of the Clean Air Act, as well as regulations currently under development by the U.S. EPA, along with other alternatives to the Clean Air Act being considered by Congress such as Clear Skies and the Carper Bill, will require AEP to reduce emissions of SO_2 in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. U.S. EPA proposed in December 2003 regulation of interstate air quality that, if promulgated, will require significant additional SO_2 and NO_x emission reductions beginning in 2010. U.S. EPA also proposed in December 2003 regulation of mercury emissions from coal-fired power plants. Mercury emission reductions can be achieved with a combined SCR and WFGD system. In addition to these proposed regulations, the existing Title IV acid rain control program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

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.

- Alternatives to the SCR technology that were considered include buying needed NOx emissions allowances in the marketplace, Over-Fired Air (OFA), Water Injection, OFA & Water Injection, SNCR, OFA & PRB Fuel Blend, AEFLGR, Gas Reburn, and PRB Fuel Blend. Reliance on an uncertain marketplace for NOx emissions allowances is an unacceptable compliance strategy and would place the Company and its ratepayers at an unacceptable risk of noncompliance. The alternatives to the application of SCR technology are, in some cases, not as cost effective as SCR and, in all cases, unable to achieve the reduction required at Mitchell to meet the applicable NOx requirements for the AEP System.

Background Information

- 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 will be limestone, and the technology will provide the operational flexibility to produce a wall-board quality gypsum byproduct. The WFGD design criteria provide maximum fuel flexibility by allowing for the burning of high sulfur coal.

- The WFGD design basis for this unit includes 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 emerging technologies at some later date without major redesign of systems and provide AEP the opportunity to explore new technologies in meeting future regulations.

- The SCR system will be designed for a 90% NOx removal rate with an allowable maximum ammonia slip of 2 ppmv (at 3% O_2) and a design catalyst life that minimizes the life cycle costs. A urea to ammonia conversion system will be used to supply the SCR reactors with reagent.

Project Contacts

Contact	Name	Telephone
Project Manager	Edward V. Gilabert – FGD Jerry L. Johnson - SCR	(614) 716-1765 (614) 716-3437
Requisition Detail Provider	Edward V. Gilabert	(614) 716-1765

PROJECT APPROVAL REQUISITION

Company: Ohio Power Company **Funding Project Number:** WSN103015

Authorization Type: X Capital Improvement ___ Original Version: 00
___ Lease Improvement ___ Revision Number: 1

Business Line: Generation

Location: Kammer/Mitchell Plants Unit 0 Owned: Ohio Power Company

Project Title: Conner Run Impoundment Expansion

Brief Description: The Conner Run Impoundment is the common disposal site for fly ash from both Kammer and Mitchell Plants and coal wash slurry from Consol Energy's McElroy coal prep plant. This disposal site is critical to the continued operation of both generation plants and the McElroy mine. This CI and subsequent revisions will fund construction associated with the raising of the impoundment dam from the currently permitted elevation of 937' to 1050' by 2016 allowing continued disposal through 2031.

Project Dates:	Start:	Completion:	Authorization Needed by:
	01/01/2004	12/31/2008	12/31/2003

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$116,666	0	$116,666
This Submission	$9,527,600	$200,000	$9,727,600
Total ($)	**$9,644,266**	**$200,000**	**$9,844,266**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 3m	Senior VP	Sigmon, W	[signature]	12/17/03
$ 3m ≤ amt < $10m	Executive Vice President	Powers, R		
$ 3m ≤ amt < $10m	Vice Chairman & COO	Shockley III, T	T.V. Shockley	12/31/03
$10m ≤ amt < $30m	President, Chairman & CEO	Draper, E. Linn		
amt ≥ $ 30m	Board of Directors	Tomasky, S	Secretary	
CP&B Review	Senior VP	Munczinski, R	R Munczinski	12/29/03

Budget Availability for this Authorization: X In Budget ___ Offset
Offset (source & amount):

Generation Only: Submission approved by Project Management Review Group? ___ Yes ___ No
Nuclear Project Review Group? ___ Yes ___ No

Comments: ___

IT Project Only: ___ $100,000 - $250,000 submission approved by Executive Vice President & CIO? ___ Yes ___ No
___ > $250,000 submission approved by Office of Chairman? ___ Yes ___ No

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2002	2003	2004	2005	2006	Future Years	Total ($)
Capital	116,666	$0	$5,102,900	$984,500	$2,732,400	$707,800	$9,644,266
Removal			$200,000				$200,000
Amount to be Authorized	116,666		$5,302,900	$984,500	$2,732,400	$707,800	$9,844,266
Assoc. Fuel Exp.			$155,250	$94,750	$50,638	$56,200	$356,838

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

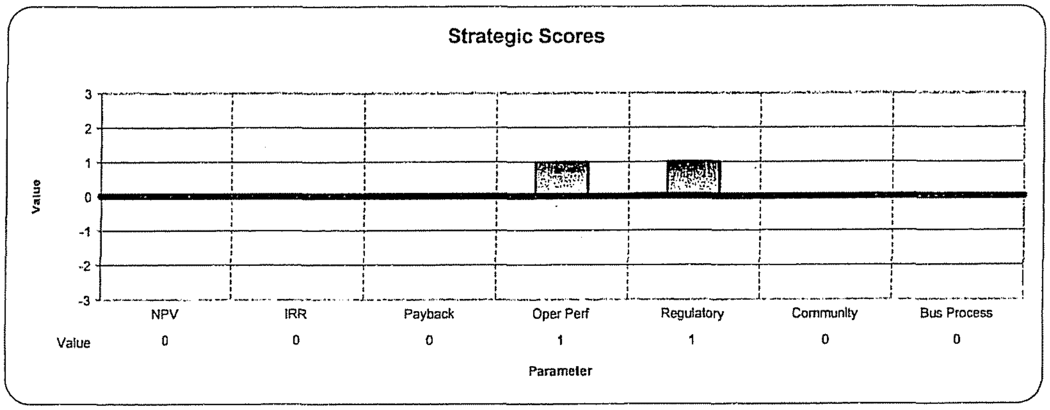
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: These results must match all background information

Scoring Summary

___ Discretionary X Mandated



Risk Scores	Consequence of not doing project			
Probability		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
	Certain/Probable	F&T&S		
	Likely/Possible			
	Rare/Remote			
				Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

PROJECT APPROVAL REQUISITION

Project Justification & Explanation of Scores

A disposal site for generated fly ash is required for the continued operation of both Kammer and Mitchell plants. In the current regulatory environment, there are no other financially viable alternatives for disposing the fly ash generated at Kammer and Mitchell Plants. Any change in the disposal location would require both Kammer and Mitchell plants to convert of a dry fly ash collection, transport and disposal system which is estimated to cost $44,000,000. There is no reasonable market for the quantity and quality of ash generated at both plants, which means that the ash would have to be placed in a newly permitted landfill with a liner and a leachate collection system. The total $14,000,000 cost *(see below for details)* for this project through 2016 when compared with the estimated $44,000,000 cost for the alternate proposal makes the proposed project financial scores 3+ and additional financial analysis not applicable.

Conclusion

The expansion of the current fly ash and mine refuse impoundment, by raising the impoundment dam, is clearly the most economically favorable resolution for the required increase in capacity. The necessary property is already owned by either AEP or Consol. Access roads, power supply and other infrastructure improvements are currently in service and suitable for continued operation and construction. The impoundment is surrounded by adjoining Consol or AEP property.

Additional Information

Alternatives Considered

The only other viable alternative approach for the continued and effective disposal of Kammer and Mitchell Plant fly ash is to convert the wet collection and transfer systems now in place at both plants to dry fly ash collection, storage, transfer and truck loading systems. In addition, a new dry ash landfill will have to be constructed on land that is now owned by others. Our estimate for the construction of a new landfill at the Henderson Hollow property, which has been studied as a potential site for a future landfill, was approximately $25,000,000. The estimated cost to convert the ash collection, storage and loading facilities to a dry fly ash collection system at both Mitchell and Kammer plants is $19,000,000. Therefore, the total estimated costs for the alternate method (i.e. converting to dry ash handling and construction of a new landfill) for disposal of fly ash produced at Kammer and Mitchell plants are $44,000,000.

Associated / Future Projects

The construction related to raising the dam and the associated expansion of the Conner Run Impoundment is anticipated to extend through 2016. We anticipate revising this CI two more times to cover the future construction cost. AEP's portion of the construction costs for the years beyond 2008 are estimated at $350,000/year with the exception of additional amounts for raising of towers associated with two additional transmission lines crossing the impoundment (Kammer Ormet #1 (50% of $1,737,150in 2009) and Kammer Ormet #2 (50% of $970,450 in 2014). That would put the total construction costs for this project at approximately $14,000,000, including overheads.

Regulatory Issues

The outflow of the impoundment is regulated by an NPDES issued by WVDEP. A "Certificate of Approval" issued by the State of West Virginia DEP, Dam Safety Section, of the Division of Water Resources, regulates the dam's design, construction and operation.

AEP

PROJECT APPROVAL REQUISITION

Background Information

The Conners Run Impoundment is the common disposal site for fly ash from Kammer and Mitchell plants and coal wash slurry from Consol Energy's McElroy Mine Wash Plant. This disposal site is critical to the operation of both power plants and the McElroy Mine. The McElroy mine and wash plant are undergoing major expansions that will double the mine's capacity and will greatly increase the wash plant's waste output. This will profoundly increase the rate of consumption of the impoundment capacity.

The remaining capacity of the impoundment is insufficient for the forecasted service life of Kammer and Mitchell Power Plants and the McElroy Mine and Wash Plant. In fact, there is less the three years of available capacity remaining.

The history of our participation in the impoundment expansion follows:
In 1973, Consolidated Coal Company (Consol Energy, Inc.) hereinafter referred to as Consol, transferred 760 acres of their land over to AEP for $10 and other good and valuable considerations. The land transfer was part of a multifaceted agreement between Consol and AEP that has been amended several times. The 25-page transfer agreement contains many provisions, which includes Consol's right to dispose their fine refuse slurry in the impoundment. The series of agreements also stipulate that AEP shall be solely responsible for the continued operation and maintenance of the Conners Run Fly Ash Impoundment and Dam. The agreements further limit the impoundment's capacity by limiting the maximum elevation of the dam. Nearly all of the surrounding land is owned by Consol. These agreements dictate that any major expansion of the impoundment must be undertaken jointly with Consol or at least with their full agreement and participation.

The impoundment, designed in the early 1970's met the environmental requirements of the time. The impoundment has neither a liner nor other sophisticated drainage and control systems that would now be required..

In short, we are constrained by agreements that allow Consol to dispose of their refuse in the impoundment that is operated and maintained at AEP's expense. In addition, we are also constrained by the agreements to a maximum impoundment capacity (AEP does not own the land above the 1000' elevation). A joint use/joint funding agreement is currently be finalized between AEP and Consol which would result in cost sharing for the future construction and eventual closure of the eventual closure of the impoundment.

Both AEP and Consol realize the value of this cost effective waste storage impoundment, which is critical to both operations.

Project Contacts

Contact	Name	Telephone
Project Manager	Pedro J. Amaya	614 716 2926
Requisition Detail Provider	John F. Mainieri	614 716 2942

AEP®

PROJECT APPROVAL REQUISITION

Ohio Power Company - Generation **Funding Project Number:** MLWALLBDP

Authorization Type: X Capital Improvement
___ Lease Improvement

X Original Version: 00
___ Revision Number: ___

Business Line: Generation

Location: Mitchell Generating Plant

Project Title: Mitchell Wallboard Facility Conveyor System

Brief Description: Perform the detailed engineering, procurement, construction and commissioning of an overland gypsum conveyor from the Mitchell site to the wallboard manufacturing facility, including modifications and/or additions to the presently designed FGD gypsum system, gypsum storage facility, barge unloading equipment, and miscellaneous site infrastructure facilities.

Project Dates:	Start:	Completion:	Authorization Needed by:
	11/01/2004	03/31/2007	07/29/05

Expenditure to be Authorized (fully loaded)	Capital	Removal	Total Cost ($)
Previously Approved Amount	0	0	0
This Submission	$33,227,523	0	$33,227,523
Total ($)	**$33,227,523**	**0**	**$33,227,523**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $10m	Senior VP/or As Delegated	Sigmon, W.	[signature]	8/11/05
$10m ≤amt < $20m	Executive Vice President/COO	Powers, R.	[signature]	8/22/05
$20m ≤amt < $50m	Chairman, President & CEO	Morris, M. G.	[signature]	8.23.05
amt ≥$50m	Board of Directors	Cross, J.	Secretary	
CP&B Review	Senior VP	Munczinski, R	[signature]	8/18/05

Budget Availability for this Authorization: X In Budget ___ Offset
Offset (source & amount):

***Generation Only*:** Submission approved by Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments: ___

IT Project Only: ___ $100,000 - $250,000 submission approved by Executive Vice President & CIO? ___ Yes ___ No
___ > $250,000 submission approved by Office of Chairman? ___ Yes ___ No

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2003	2004	2005	2006	2007	Future Years	Total ($)
Capital	$0	$248,208	$3,271,401	$29,159,980	$547,934		$33,227,523
Removal	$0	$0	$0				$0
Amount to be Authorized	$0	$248,208	$3,271,401	$29,159,980	$547,934		$33,227,523
Assoc. O & M	$0	$0	$0				$0

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

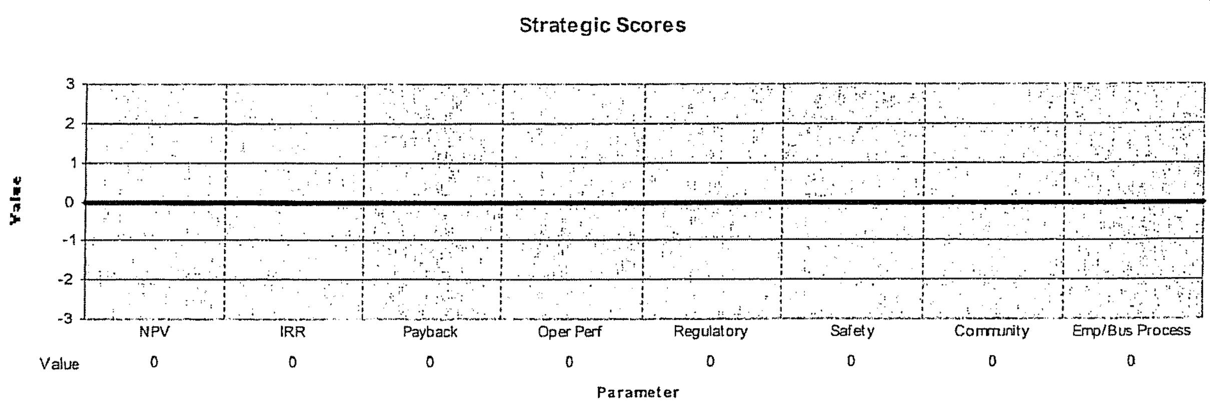
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A %	$ N/A	N/A years	N/A %

Note: These results must match all background information

Scoring Summary

X Discretionary ___ Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			
	Rare/Remote			
	Risk Type Key: F = Financial, T = Technical, S = Sociopolitical			

Please see Project Justification and Glossary for explanation of Scores

Project Justification & Explanation of Scores

- On March 11, 2005, AEP and BPB executed a 25-year supply agreement for the delivery of WFGD synthetic gypsum to a new BPB wallboard manufacturing facility to be located adjacent to the Mitchell Plant. This agreement requires AEP to provide a base volume of 800,000 dry tons of gypsum per year, of which approximately 600,000 tons will be supplied from Mitchell with the remaining volume to be supplied from Cardinal Plant.

- This gypsum supply agreement will enable AEP to avoid the construction of a landfill for the disposal of gypsum produced by the Mitchell WFGD's and reduce costs for gypsum disposal at Cardinal Plant. The avoided capital cost has been estimated at $171M to $222M. In addition, the agreement will also allow Mitchell to avoid the O&M expense of $3-$5/ton associated with gypsum disposal.

- In order to provide gypsum from Mitchell to the adjacent wallboard facility, the FGD gypsum material handling system, as designed, must be modified. The present design takes gypsum from the dewatering building and conveys it to an enclosed gypsum storage pile just south of the plant where it would be further conveyed to a barge load out facility at the riverbank. A covered gypsum conveying system must now be extended to run further south of the plant and cross Highway 2 to reach the proposed wallboard facility location.

- When initially comparing the incremental capital costs to modify the presently designed gypsum material handling system, estimated at $17.1M to $27.9M, to the avoided landfilling costs noted above, the NPV of avoided capital is $127,000,000. The present estimate is $30.7M.

- The following are the major changes and additions to the existing gypsum material handling system required to support the wallboard facility:

    - The gypsum material handling conveyor will be extended approximately 4700 feet beyond the site to the wallboard facility.
    - Additional barge unloading equipment and conveyors are required to unload covered gypsum barges arriving from Cardinal Plant.
    - Modifications are required to the proposed river cells to accept additional unloading equipment.
    - The addition of a portal scrapper reclaimer in the gypsum storage pile and reclaim hopper and blend feeder is required for high capacity reclaim and management of off-spec gypsum.
    - A chemistry laboratory and limestone sampling are required to ensure that gypsum quality is maintained and meets the agreement's contractual specifications.
    - Purchase of a parcel of land south of the site for the conveyor and railroad spur right of way is required.
    - High voltage line relocation is required to facilitate the extended conveyor.
    - Ancillary systems – electrical power, fire protection, underground relocations, etc., are required to support infrastructure requirements.

- The initial gypsum material handling system was previously released for procurement, with erection scheduled to start August 2005. The expanded wallboard related changes require detailed engineering and design for the system modifications to start in June 2005 to support a wallboard manufacturing in-service date of mid-2007.

- The requested funding is for Mitchell Plant specific expenditures. Separate CIs will be generated to cover Cardinal and any Mountaineer specific costs associated with the wallboard facility.

PROJECT APPROVAL REQUISITION

Conclusion

- Providing gypsum to a wallboard facility close to the Mitchell site from various plants, including Mitchell, is the overall most economic means of disposing of gypsum, the waste by-product of the WFGD's.

Additional Information

Regulatory Issues

- Issues that need to be finalized include a storm water drain permit for any acquired property, a highway crossing permit for the conveyor, and environmental remediation of any acquired property, if required. River cell work is already covered by the existing Army Corp of Engineers permit application.
- Site fugitive dust emission sources including the extension of the gypsum material handling system to the wallboard facility have been included in the project's Regulation 13 permit application submittal.

Alternatives Considered

- The wallboard agreement represents the outcome of a rigorous economic evaluation of different scenarios involving landfill related costs among Mitchell, Cardinal and Mountaineer against the benefits and liabilities of a long term contract with a third party. Whether it was building miles of conveyors at Mitchell or barging all of Mitchell's gypsum to a "Mega" landfill at Mountaineer, the least cost option for all three plants is this gypsum supply contract with BPB.
- Trucking gypsum to the wallboard facility was evaluated against extending the proposed gypsum material handling system. Total evaluated costs, including O&M, favored installing the conveyor system.

Project Contacts

Contact	Name	Telephone
Project Manager	E. V. Gilabert	(614) 716-1765
Requisition Detail Provider	E. V. Gilabert	(614) 716-1765

PROJECT APPROVAL REQUISITION

Ohio Power Company - Generation **Funding Project Number: 000009803**

Authorization Type: X Capital Improvement
___ Lease Improvement

___ Original Version: 00
X Revision Number: 05

Business Line: **Generation**

Location: **Mountaineer Generating Plant**

Project Title: **Gypsum unloading and transfer equipment engineering**

Brief Description: **Complete the construction and commissioning of a gypsum and wastewater cake barge unloader, conveyors and overland conveying system. The system is designed to unload gypsum/wastewater cake from barges, transfer to the overland conveying system for transport to Little Broad Run landfill. The gypsum/wastewater cake unloaded from barges will be generated at Mitchell and Cardinal Plants.**

Project Dates:	**Start:**	**Completion:**	**Authorization Needed by:**
	07/19/2004	**1/07/2007**	**6/30/2006**

Expenditure to be Authorized (fully loaded)	**Capital**	**Removal**	**Total Cost ($)**
Previously Approved Amount	10,269,605	0	10,269,605
This Submission	2,853,479	0	2,853,479
Total ($)	**13,123,084**	**0**	**13,123,084**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $10m	Senior VP/or As Delegated	Sigmon, W.		
$10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $50m	Board of Directors	Keane, J.	Secretary	

CP&B Review	Senior VP	Munczinski, R		

Budget Availability for this Authorization: ___ In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by

Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments: ______________________________

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2003	2004	2005	2006	2007	Future Years	Total ($)
Capital	$	$582,378	$1,553,302	$10,979,806	$7,598		$13,123,084
Removal	$0	$0	$0				$0
Amount to be Authorized	$	$582,378	$1,553,302	$10,979,806	$7,598		$13,123,084
Assoc. O & M	$0	$0	$0				$0

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

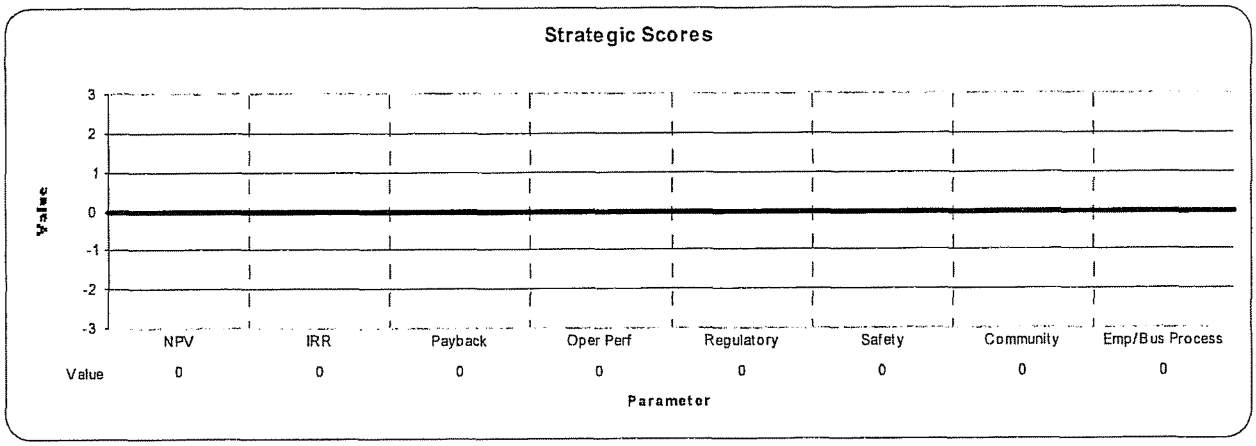
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A %	$ N/A	N/A years	N/A %

Note: These results must match all background information

Scoring Summary

___ Discretionary   X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			
	Rare/Remote			
	Risk Type Key: F = Financial, T = Technical, S = Sociopolitical			

Please see Project Justification and Glossary for explanation of Scores

PROJECT APPROVAL REQUISITION

Project Amendment Explanation

- As detailed engineer progressed thru completion, and issued for construction (IFC) drawings and specifications were released it became apparent that the IFC documents differed from the scope previously identified in revision four of this CI. Major scope changes include the addition of three river cells to support the conveyor from the river unloading cell to land. Additional charges for relocate existing utilities and development of temporary access roads for access during construction. The final cost addition to the CI is for schedule acceleration costs for the erection contractor. The late issue of engineering drawings and specifications, which lead to late construction turn over dates of foundation to the erection contractor, has caused the construction schedule duration to be shortened by two months. To maintain schedule we must work additional days per week and extended work hours per day.

- Additional costs for this revision are direct labor, materials and AEP Indirect costs. A break down of these costs are as follows
  - Labor increased $1,001,491
  - Material increased $973,066
  - Equipment costs increased $676,287 (FMC schedule acceleration costs)
  - Indirects were reduced $518,377
  - AEP PMEC increased $189,497
  - Contingency increased $50,847
  - SS&W engineering decreased $189,495

- In an effort to reduce the cost overrun on this CI the remaining foundation, utility, and access work has been contracted on a time and material basis. The erection contractor (FMC) remains on a firm price contract.

- As detailed engineer progressed thru completion, and issued for construction (IFC) drawings and specifications were released it became apparent that the scope of work in the IFC documents differed from the scope previously identified in revision three of this CI. Major scope changes include the addition of three river cells to support the conveyor from the river unloading cell to land. Additional charges for relocate existing utilities and development of temporary access roads for access during construction. Schedule constraints increased the cost of conveyor erection above those anticipated.
- In an effort to reduce the cost overrun on this CI the remaining foundation, utility, and access work has been contracted on a time and material basis. The erection contractor remains on a firm price contract because discussions with the contractor reveled that converting to a time and material basis would not result any savings.

Project Justification & Explanation of Scores

- In order to comply with US EPA Clean Air Interstate Regulations, flue gas desulfurization (FGD) units will be retrofitted on AEP's Mountaineer (MT), Mitchell (ML) and Cardinal (CD) plants. These FGD will produce gypsum as a by-product. Some of this gypsum will be sent to a wallboard plant and the remainder will be disposed of in landfills. In addition to the gypsum produced at Mitchell and Cardinal, both will produce a wastewater cake from their water treatment process. The Mitchell and Cardinal landfills are not expected to be ready in time for initial FGD operation. The least cost option for interim disposal is to place gypsum/wastewater cake from ML and CD in Mountaineer's Little Broad Run landfill. This will necessitate installing the ability to unload CD and ML gypsum/wastewater cake from the river and transport it to the landfill at MT. Gypsum/cake will be transported via an over land conveying system.

- Funding has been previously approved for the gypsum/wastewater cake unloader and overland conveying system and the conceptual engineering, scheduling, environmental planning and permitting to obtain a detailed cost estimate for the installation of the gypsum unloader and conveying system has been obtained.

PROJECT APPROVAL REQUISITION

- The design of the gypsum/wastewater cake system includes unloading gypsum/wastewater cake from the river via an E-Crane unloader. The gypsum/cake will be placed on a conveyor and transported to transfer tower number four. The overland conveyor system starts at transfer tower number four. The overland conveyor system is comprised of five conveyors and six transfer tower. Multiple options have been reviewed on how to handle the gypsum/cake and this option has been determined to be the only option that can handle the amount of materials (tons) that are required and stay compliant within our permitted fugitive dust limit.

- To take advantage of this option, additional funding is being requested to complete construction and commissioning of the system.

Process

- Mountaineer will transfer gypsum from their FGD process to Little Broad Run landfill via the overland conveyor system. Mountaineer's gypsum will be weighed before it is placed on the overland conveying system. This weight will be used to determine the inter company billing for the use of the overland conveyor. Gypsum will be transferred via the overland conveying system to a stack out pad at the landfill. Gypsum will be manually loaded into trucks at the stack out pad and transported to the active storage site in Little Broad Run Landfill. In the event the overland conveyor may go down for maintenance Mountaineer has the ability to stack out their produced gypsum onto a open conical pile capable of holding 51 hours of full load production. In the event this scenario would occur the gypsum stacked out on the conical pile would need to be loaded manually into dump trucks and hauled to the active storage site in the landfill.

- Mitchell and Cardinal gypsum/waste water cake will be transferred by, the barge unloader (E-Crane) and conveyors, from the river to the overland conveyor. This material will be weighed by a belt scale system. This weight will be used to determine the inter company billing for the use of the overland conveying system. The gypsum and wastewater cake will be transferred to the stack out pad at the landfill. Gypsum/Cake will be manually loaded into trucks at the stack out pad. Trucks will be required to cross a weight scale to determine the basis for billing. Due to the wetness of the material being hauled and the possibility of the material sticking to the trucks dump beds the trucks will be required to weigh empty and full. After the weight has been determined the material will be hauled to the active storage site in the landfill. In the event the overland conveyor may be out of service for any reason the material in the barges will not be unloaded until the conveyor system is put back in service.

- Funding for this portion of the scope of work will be thru OPCO. This is required due to Mitchell and Cardinal Plants' disposal needs. Mountaineer does not require river off loading of gypsum/wastewater cake for their process. The addition of a (gypsum/wastewater cake) river cell, unloading hopper, conveyors and transfer tower number four are highlighted on the print that has been added to this CI request. The print depicts the equipment that will be funded by this CI.

Conclusion

- Funding for construction and commissioning of a (gypsum/waste water cake) river cell, unloading hopper, conveyors and transfer tower four is required to support the operation of the WFGD systems at Mitchell and Cardinal Plants.

- This CI does not provide funding for the entire gypsum handling system. An additional CI (000012019) was routed for APCO, which completes the funding required for the entire gypsum handling system. Both CI's are required for the completion of the gypsum handling system.

- This strategy supports the construction of WFGD systems at Mountaineer, Mitchell and Cardinal Plants for operation in 2007.

PROJECT APPROVAL REQUISITION

Additional Information

Regulatory Issues

- The use of the (gypsum/wastewater cake) river cell, unloading hopper, associated conveyors and transfer tower four are for Mitchell and Cardinal Plants use only.
- Mountaineer, Mitchell and Cardinal will utilize the overland conveying system.
- Billing for the use of the over land conveying system, truck scales and truck wash system will be thru affiliate transaction. All transactions will be based on the amount of Cardinal and Mitchell gypsum placed in Little Broad Run Landfill. All material will be weighed to provide the basis for the billing.
- Operation and maintenance of the barge unloader and over land conveying system would be handled by APCO with affiliate transactions to OPCO based on usage (tons).

Project Contacts

Contact	Name	Telephone
Project Manager	Chris Beam	(614) 716-1177
Requisition Detail Provider	Chris Beam	(614) 716-1177

AEP®

PROJECT APPROVAL REQUISITION

Company: Ohio Power **Funding Project Number:** ML2SCO004

Authorization Type: X Capital Improvement ___ Lease Improvement

X Original Version: 00
___ Revision Number: ___

Business Line: Generation

Location: Mitchell Unit 2

Project Title: ML-2 T/R Set Replacement Program (Mitchell Project # ML2SCO004)

Brief Description: The T/R sets on Mitchell Unit 2 will be replaced between 2005 and 2006. The replacement program is justified by marginal ESP performance, multiple controls issues, undersized power cabling, and other electrical and operating issues that can be remedied with the capital improvements outlined in this CI. One half of the existing T/R sets will be removed and replaced with conventional design, non-PCB T/R sets in 2005. The other half of the T/R sets will be replaced with high frequency, non-PCB sets in 2006. This program begins a fleet-wide effort to eliminate all risks involved with PCBs.

Project Dates:	Start:	Completion:	Authorization Needed by:
	03/01/2005	12/31/2006	6/24/2005

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	0	0	0
This Submission	$8,351,205	0	$8,351,205
Total ($)	**$8,351,205**	**0**	**$8,351,205**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W.	W. Sigmon	6/27/05
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.		
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.		
amt ≥ $ 50m	Board of Directors	Keane, J.		

CP&B Review	Senior VP	Munczinski, R	John Torpy for RPM	7/6/05

Budget Availability for this Authorization: ___ In Budget x Offset

Offset (source & amount): INCCAPINV -- $2,536K

Generation Only: Submission approved by

Project Management Review Group? x Yes ___ No
Nuclear Project Review Group? ___ Yes x No

Comments: ___

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule (fully loaded)

Year	2002	2003	2004	2005	2006	Future Years	Total ($)
Capital				$5,035,120	$3,316,085		$8,351,205
Removal				0	0		0
Amount to be Authorized				$5,035,120	$3,316,085		$8,351,205
Assoc. O & M				$991,000	$409,000		$1,400,000

Note: Operating & Maintenance dollars are assumed to be <u>in budget</u> or offset in the year spent.

Financial Analysis Summary

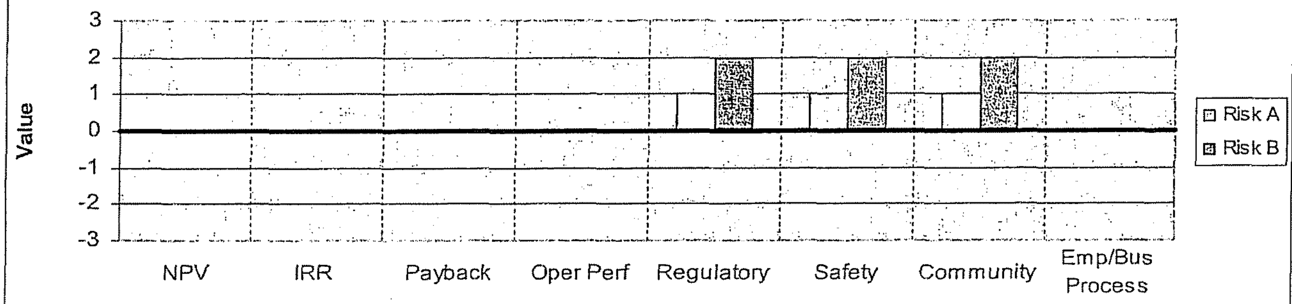
Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: This project was not justified by economics. It is justified on an environmental basis.

Scoring Summary

___ Discretionary   _x_ Mandated

Strategic Scores for:
Risk A. A PCB Release to the ESP Roof.
Risk B. A PCB release to the ESP Internals.



	NPV	IRR	Payback	Oper Perf	Regulatory	Safety	Community	Emp/Bus Process
Risk A	0	0	0	0	1	1	1	0
Risk B	0	0	0	0	2	2	2	0

Parameter

PROJECT APPROVAL REQUISITION

Risk Scores – Risk A. A PCB Release to the ESP Roof.				
		Consequence of not doing project		
Probability		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
	Certain/Probable			
	Likely/Possible			F,S,T
	Rare/Remote	F,S,T	F,S,T	
Risk Type Key: F = Financial, T = Technical, S = Sociopolitical				

Risk Scores – Risk B. A PCB Release to the ESP Internals.				
		Consequence of not doing project		
Probability		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
	Certain/Probable		F,S,T	
	Likely/Possible	F,S,T		
	Rare/Remote			
Risk Type Key: F = Financial, T = Technical, S = Sociopolitical				

Project Justification & Explanation of Scores

The existing T/R sets contain polychlorinated biphenyls (PCBs) and have been in service for 27 years. The sets are approaching their design life of 30 years and while the possibility of a PCB release to the environment is rare, the failure rate of a T/R set increases with age. Should the PCBs penetrate the designed barriers and possibly enter the electrostatic precipitator (ESP), the consequences of a release could be minor to severe. Once inside the ESP, the PCBs will have potential paths to the stack and the fly ash pond complex. In these environments, containment and removal of the PCB would be costly and socio-politically damaging.

In 2004, AECE conducted a detailed engineering study outlining hypothetical scenarios by which PCBs could escape from a T/R set and leak into the ESP. In addition, the study outlined options for managing the potential risks involved with a PCB release. Regardless of the release scenario, the long-term recommendation for all AEP units using PCB-filled T/R sets was a replacement program.

A PCB release occurred at Mitchell Plant shortly after the engineering study was conducted. A T/R set failure occurred which resulted in the release of approximately 30 gallons of PCB fluid into the girder box. The cleanup costs for this release amounted to approximately $150,000.

As a result of the study and the release, AEP management has concurred with the recommendation to begin a pro-active replacement program of all PCB-filled ESP T/R sets on the fleet. The PMRG approved $2.8M in direct costs to purchase new T/R sets for Unit 2. However, after a complete engineering review of the ESP and its electrical components, the work scope for Mitchell is $6.2M in direct costs [$9.8M in fully loaded costs].

This is an environmental and safety related project and as such, the typical cost/benefit analysis is not warranted. Elimination of the existing T/R sets reduces the environmental risk and the exposure of personnel to PCBs. Also, during the engineering review of this project, it was discovered that the existing 2/0 aluminum power cable is undersized for its required ampacity. The CI will correct this and other system deficiencies as detailed below.

T/R Sets and Associated Bus Duct

The existing T/R sets are conventional 1000 mA and provide a current density (charge potential) of 44 mA/1,000 ft^2. This potential is significantly below the AEP fleet average of 80 mA/1,000 ft^2. This hinders the ability of Mitchell Plant, located in West Virginia, to meet a strict 10% opacity limit. (The opacity limit in most other regions is 20 %.) Since 1995, 10,000 6-minute opacity exceedances have occurred at Mitchell. In addition, opacity curtailments and other ESP issues cost AEP $2.1M in lost generation between 1997 and 2004 (see ATTACHMENT 1). Any modification to the ESP that will aid collection is desirable.

PROJECT APPROVAL REQUISITION

As such, AEP will purchase new 1200 mA T/R sets. These T/R sets will provide an increased current density of 70 mA/1,000 ft^2 to the ESP. (Note that even with the 1200 mA sets, Mitchell Plant will remain below the fleet average for current density.) The additional power that the 1200 mA set provides to the ESP can be purchased for no differential material or install costs from an in-kind 1000 mA replacement.

A total of 64 - 1200 mA sets will be installed in the odd-numbered fields (1, 3, 5, and 7) of the ESP in 2005. In the even fields (2, 4, 6, and 8), 64 - high frequency (HF) T/R sets are intended to be installed in 2006. If the HF sets are commercially unavailable, conventional T/R sets will be used.

The conventional and HF T/R sets draw the same primary voltage and current of 575V and 180A. However, the HF T/R sets output a much higher average voltage at the same secondary current of 1200 mA. This additional power allows for greater ash collection in the ESP. AEP is successfully utilizing HF sets on Big Sandy 1, Big Sandy 2, and Conesville 4.

These new, additional T/R sets will restore the ESP to its original degree of sectionalization and provide improved ESP performance and reliability.

The new conventional T/R sets have a different physical arrangement than the existing sets and therefore require new bus duct. The new ducts will be purchased from the T/R set manufacturer. The HF sets, which sit directly on the girder box, require no bus duct.

<u>Cable and Breakers</u> -*The new cable and breakers are an extension of the original work scope.*

The existing power cable for the T/R sets is 2/0 aluminum. The 2/0 aluminum cable is rated 132A at its operating temperature. Per AEP's Engineering Guidelines and the National Electric Code (NEC), the existing cable is undersized for its current load of 143 A and the future load of new T/R sets. Evidence of overheat can be found at the plant in the brittle cable insulation near the T/R set and the power lugs between the power cable and the T/R set, which occasionally burn off. This presents an unsafe condition and reduces the ability of the ESP to maintain environmental compliance. This CI will cover the replacement of all 2/0 aluminum power cable with 4/0 copper cable.

Protection for the new cable requires new 225A breakers to be installed as well.

<u>Cable Tray</u> -*The new cable tray is an extension of the original work scope.*

The cable tray runs from the ESP control room, up the side of the ESP, and across the roof of the ESP. There is one cable tray to support each field of T/R sets. The existing trays on the roof of the ESP are in poor condition. Nearly all of the transition pieces have fallen or rusted out and the trays have been exposed to a harsh environment for the last 30 years. It is uncertain how they will withstand the installation stress of new, heavy 4/0 3/C cabling. New fiberglass cable trays will be installed on the ESP roof and six feet down the side of the ESP.

<u>Automatic Voltage Controls (AVCs) and Rapper Controls</u> – *The new controls are an extension of the original work scope.*

The existing AVCs (Solvera 6001 Series) were installed at Mitchell in 2000. On average, the failure rate of the 6001 controls is 10%. The 6001 microprocessor, although functional, operates at design at its maximum output. The existing controls will be replaced with the Solvera 9000 series which is a more robust and reliable design. AEP has over 900 units of the Solvera 9000 control installed across the fleet and the failure rate of this control is less than 1%.

The existing Solvera rapper controls at Mitchell are in good operating condition and will not be replaced. However, a modification to the controls to monitor the feedback of the rapper motor current and an update to the host management system (HMS) will be incorporated at a small incremental cost. These updates will improve the control of the both the collecting system (CS) and discharge system (DS).

PROJECT APPROVAL REQUISITION

<u>SCRs</u> - *The new Silicon Controlled Rectifiers (SCRs) are an extension of the original work scope.*

The existing SCRs at Mitchell are rated at 185. The reactors have a high failure rate of approximately 15 per year per unit because the rating of 185A is marginally sized for the existing load of 143A. The new conventional and HF T/R sets will draw 180A and therefore require new SCRs.

<u>CLRs</u> - *The new Current Limiting Reactors (CLRs) are an extension of the original work scope.*

The existing CLRs at Mitchell are rated at 143A and are undersized for the new T/R sets.

<u>Key Interlock System</u> - *The interlock system is an extension of the original work scope.*

The existing key interlock system is in very poor condition with multiple access door locks missing or broken. The system is in place to provide controlled entry to a statically energized area when the ESP has been de-energized and is a significant safety issue. A new key interlock system will be purchased under this CI.

<u>Fire Detection System</u> - *The new system is an extension of the original work scope.*

PCB is non-flammable and therefore there exists no fire detection equipment on the ESP roof. The new T/R sets will use a silicon dielectric fluid. Although silicon has a very low flammability, its flammability is greater than PCB and it will burn. The Fire and Risk Control group requires Protectowire to alarm the control room of a fire on the ESP and fire extinguishers across the ESP roof.

<u>Grounding Grid</u>

The ESP has no physical grounding grid. A grid is needed to suppress stray voltages introduced into the system that can cause failure of control memory cards and circuit traces. This CI will cover the installation of a ground grid.

Conclusion

The project work scope will be completed over 2 years. The scope for the fall outage of 2005 covers the installation of:

- 64 conventional, 1200 mA T/R sets in fields 1, 3, 5, and 7
- 64 bus duct assemblies
- 64 SCRs
- 64 CLRs
- 64 AVCs and updates to the CS and DS rapping and Host Management Systems
- A grounding grid for 128 T/R sets
- Cable trays to support 128 T/R sets
- Power cable for 128 T/R sets
- A fire detection system for the entire ESP roof
- A key interlock system for the entire ESP

The fall outage of 2006 covers the installation of:

- 64 HF, 1200 mA T/R sets in fields 2, 4, 6 and 8

The capital investments outlined in this CI, combined with O&M improvements to the internals of the ESP, will permit Unit 2 to achieve consistent particulate compliance in the coming years. The ESP performance, in addition to future SO_2 and NO_X controls, is an integral part of Mitchell's fleet position in the environmental compliance strategy for AEP.

Other Alternatives Considered

Not applicable.

Associated/Future Projects

A similar work scope is being developed for the Mitchell Unit 1 spring outage of 2006. The duration of the Unit 1 outage is only 8 weeks compared to the 14 and 12 week outages for Unit 2. As such, additional work shifts will be necessary to complete the scope in the allotted time. A separate CI will be prepared for Unit 1.

Regulatory Issues

The work scope outlined in this CI addresses several regulatory issues.

- Safety and environmental issues regarding PCBs contained in the T/R sets at Mitchell will be eliminated.
- Particulate capture will improve as a result of adding increased power and sectionalization to the ESP.
- Within the next 3 to 5 years under Title V, Mitchell Plant will be required to develop a Continuous Assurance Monitoring (CAM) Plan for its ESP. With higher power levels, upgraded controls, and a demonstration improved performance, Mitchell will be in a good position for developing a plan with the state of West Virginia.

Project Contacts

Contact	Name	Telephone
Project Manager	(TBD)	(TBD)
Requisition Detail Provider	Jill Sustar	200-1835

PROJECT APPROVAL REQUISITION

Other Alternatives Considered

Not applicable.

Associated/Future Projects

A similar work scope is being developed for the Mitchell Unit 1 spring outage of 2006. The duration of the Unit 1 outage is only 8 weeks compared to the 14 and 12 week outages for Unit 2. As such, additional work shifts will be necessary to complete the scope in the allotted time. A separate CI will be prepared for Unit 1.

Regulatory Issues

The work scope outlined in this CI addresses several regulatory issues.

- Safety and environmental issues regarding PCBs contained in the T/R sets at Mitchell will be eliminated.
- Particulate capture will improve as a result of adding increased power and sectionalization to the ESP.
- Within the next 3 to 5 years under Title V, Mitchell Plant will be required to develop a Continuous Assurance Monitoring (CAM) Plan for its ESP. With higher power levels, upgraded controls, and a demonstration improved performance, Mitchell will be in a good position for developing a plan with the state of West Virginia.

Project Contacts

Contact	Name	Telephone
Project Manager	(TBD)	(TBD)
Requisition Detail Provider	Jill Sustar	200-1835

PROJECT APPROVAL REQUISITION

Attachment 1. ML Opacity Exceedances and Curtailments.

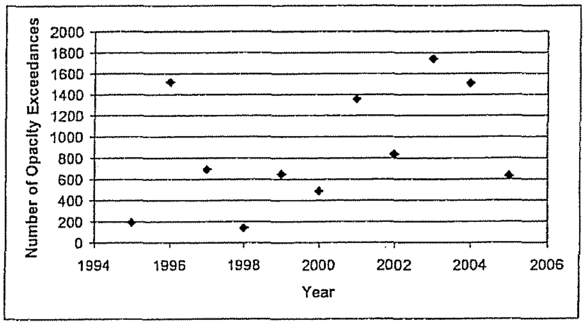
OPACITY 6 MINUTE EXCEEDANCES

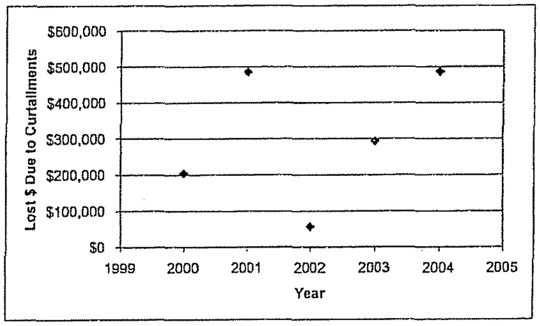
YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	
1ST QUARTER	29	294	67	19	170	74	467	289	137	920	631	
2ND QUARTER	55	107	220	15	300	117	288	56	882	145		
3RD QUARTER	25	810	51	40	63	55	205	116	424	273		
4TH QUARTER	83	306	353	65	113	240	396	371	297	172		Total
TOTAL	192	1517	691	139	646	486	1356	832	1740	1510	631	9740

$ Lost due to Opacity Curtailments and Other Precipitator Issues

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005*	Total
				$617,770		$204,111	$485,393	$56,253	$292,726	$485,743	$1,164,156	$3,306,152

* Year to Date





PROJECT APPROVAL REQUISITION

Company: **Ohio Power** **Funding Project Number:** 000011001

Authorization Type: X Capital Improvement
___ Lease Improvement

X Original Version: 00
___ Revision Number: ___

Business Line: Generation

Location: Little Broad Run Landfill - Sporn

Project Title: Little Broad Run Landfill & New Site

Brief Description: **Perform construction of the Mountaineer Little Broad Run (LBR) Landfill Cells 6 & 7 for the co-disposal of Mountaineer FGD waste and Mountaineer/Sporn Plant flyash. Perform the engineering, design and permitting of cells 8-11 of LBR. Perform new siting studies, site assessments, permitting, land options and procurement for a new landfill.**

Project Dates:	**Start:**	**Completion:**	**Authorization Needed by:**
	03/01/05	11/30/08	02/21/05

Expenditure to be Authorized (fully loaded)	**Capital**	**Removal**	**Total Cost ($)**
Previously Approved Amount	0	0	0
This Submission	6,546,032	0	6,546,032
Total ($)	**6,546,032**	**0**	**6,546,032**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W.	W. Sigmon	5/2/05
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.	R. Powers	5/10/05
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.	M. G. Morris	5.11.05
amt ≥ $ 50m	Board of Directors	Keane, J.		
CP&B Review	Senior VP	Munczinski, R	John Torpey for RGM	5/5/05

Budget Availability for this Authorization: ___ In Budget X Offset

Offset (source & amount): **000011000 - $1,700K**

Generation Only: Submission approved by Project Management Review Group? ___ Yes X No
Nuclear Project Review Group? ___ Yes X No

Comments: ______

IT Project Only: ___ $250,000 ≤ $1,000,000 submission approved by EVP or Delegated to SVP only? ___ Yes ___ No
___ > $1,000,000 submission approved by Office of Chairman? ___ Yes ___ No

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2005	2006	2007	2008	2009	Future Years	Total ($)
Capital	1,806,644	1,486,260	2,192,988	1,060,140			6,546,032
Removal							
Amount to be Authorized	1,806,644	1,486,260	2,192,988	1,060,140			6,546,032
Assoc. O & M							

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

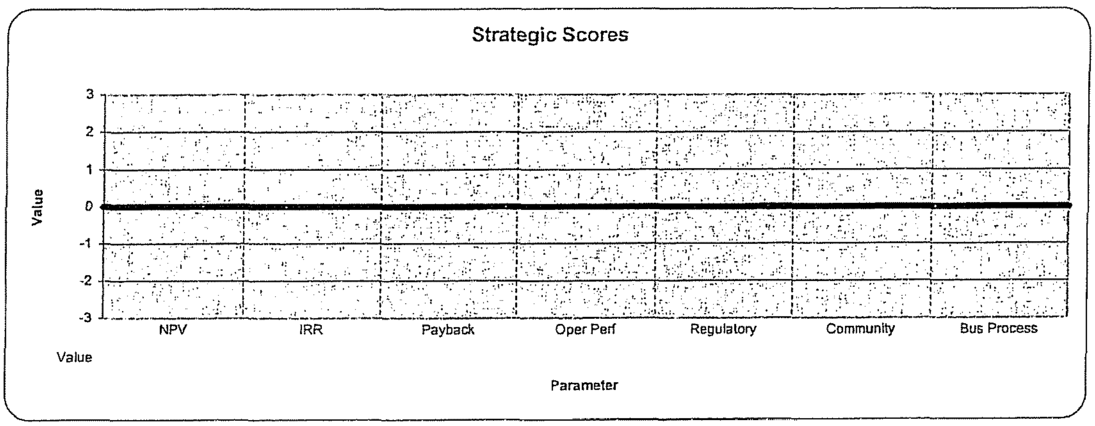
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	N/A	N/A	N/A	N/A

Note: These results must match all background information

Scoring Summary

___ Discretionary   X Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable			
	Likely/Possible			
	Rare/Remote			
				Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

PROJECT APPROVAL REQUISITION

Project Justification & Explanation of Scores

The scope of this CI is to construct areas 6 & 7 of the existing Little Broad Run (LBR) Landfill to support the Mountaineer FGD project and disposal of flyash from Mountaineer and Sporn. The engineering, design and re-permitting of cells 6 & 7 have been completed under the MT FGD CI. This phase of work will include the following activities:

- Construction of areas 6 & 7 of LBR to allow co-disposal of flyash with FGD waste gypsum
- Engineering, Design and Permitting of LBR areas 8-11
- Perform and new landfill siting study and site assessments
- Procure new land options and land procurement
- Closure of cells 6 & 7

Funds are being requested to complete this phase of the landfill activities. Future phases will be completed through requested CI revisions at a later date.

- The project economic justification is based upon a capitalization of the estimated costs for disposal of the waste. Disposal within the captive Little Broad Landfill is expected to be in the $9-$10/ton range for each of the 4 years. In comparison with the expected capitalized costs of disposal into a commercial landfill with costs in the $52-$57/ton range. Based upon this economical analysis, it is obvious the most economical choice for disposal is the LBR landfill.
- The FGD environmental program will fund a total of $22 million in controllable costs for this project. This represents approximately 57% of the total capital costs associated with a 5 year disposal capacity (Cells 6 & 7).

Conclusion

- This FGD landfill project will ensure that these long term activities do not delay operation of the Mountaineer FGD project and Mountaineer and Sporn plants.
- The development of the LBR landfill is clearly the most economical solution for disposal of our gypsum and flyash waste.

Additional Information

Associated / Future Projects

- This funding request is for Sporn Plant's (OPCo) portion of the costs for the landfill (71.4% of Sporn's total). Companion CIs for Sporn Plant's (APCo) portion of costs (000011339) and Mountaineer Plant's portion (000011000) are also being routed for approvals.

Regulatory Issues

- The re-permit application for LBR has been submitted to the WVDEP for their approval and acceptance. There is a high level of confidence that this permit will be accepted.

Background Information

- WFGD permitting, engineering, design and subsequent FGD construction are funded under CI# 000007068.
- The initial engineering and design of areas 6 & 7 has been completed under the MT FGD CI. A portion of these costs ($186k) are being transferred to this CI for capitalization purposes.
- Funds are being requested for the completion of this phase of work which is scheduled to be completed 11/08.
- The construction of cells 6 & 7 will provide at least 4 years of disposal capacity for Mountaineer and Sporn plants.
- The LBR landfill is being permitted to accept gypsum from both Cardinal and Mitchell plants.
- Funding for future phases of work will be requested by a CI revision at a later date.

PROJECT APPROVAL REQUISITION

Project Contacts

Contact	Name	Telephone
Project Manager	Robert Cundiff	614-716-2076
Requisition Detail Provider	Robert Cundiff	614-716-2076

Date May 15, 2006

AEP

Company	CI/LI/CPP/Program Number	Version
Indiana Michigan Power	RKIMC0652	

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B PC 5-15-2006	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B PC 5-15-2006

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Torpey		AEG Joint Plant CI# RKAEG0652
2	R. E. Munczinski	for REM	5/15/06
	S. Smith		
	S. Tomasky		
	B. Bond (SWEPCO T&D)		
	M. Heyeck		
	V. McCellon-Allen		
	M. K. Nazar		
	S. N. Smith		
	R. P. Powers		
	H. Koeppel		
	T. M. Hagan		
	J. Hamrock		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	Paula Cahill - 28th floor Ext 2494		
		5-15-2006	Approved in PowerPlant
		6-06	Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: Indiana Michigan Power RKIMC0652 Version .pdf

Please return to Capital Budgeting, 28th Floor 1RP

Date May 15, 2006

AEP

Company	CI/LI/CPP/Program Number	Version
AEP Generating Co.	RKAEG0652	1

Per Scope Review - Capital, Removal, Lease and O&M classifications appear to be appropriate	Reviewed by CP&B	Budget Dollars are in budget and/or budget transfer has been received	Reviewed by CP&B
	PC 5-15-2006		PC 5-15-2006

ROUTING:	NAME	INITIALS & DATE RELEASED	COMMENTS
	R. A. MacPherson		
1	J. Torpey		I&M Joint Plant CI# RKIMC0652
2	R. E. Munczinski	for REM	5/15/06
	S. Smith		
	S. Tomasky		
	B. Bond (SWEPCO T&D)		
	M. Heyeck		
	V. McCellon-Allen		
	M. K. Nazar		
	S. N. Smith		
	R. P. Powers		
	H. Koeppel		
	T. M. Hagan		
	J. Hamrock		
	C. L. English		
	Cecelia Androsky/Buckeye Power Approval		
	M. G. Morris		
3	Paula Cahill - 28th floor Ext 2494		
		5-15-2006	Approved in PowerPlant
		6-06	Month Included in Board Package

Alternate CP&B Contacts:
Bobby Myers - 28th Floor - Ext 2642
Pat Bachman - 28th Floor - Ext 2888

AEP Printing Services:

Scanned File Name: AEP Generating Co. RKAEG0652 Version .pdf

Please return to Capital Budgeting, 28th Floor 1RP

Generation CI/LI Approval Routing Document

Status: Approved

Last populated: 05/05/2006 02:41 PM

Plant	Unit	Funding Project #	Rev. #	Project Type
Rockport	0	RKIMC0652	0	Project
		RKAEG0652	0	

Project Title: RK06 CI Landfill Expansion

Outage Code:
(if necessary)

Brief Description of Project (sufficient to determine that the project is Capital not O&M)
Rockport Landfill Expansion

Company	LEG-9 #	Originated
Indiana Michigan Power Co.	No	05/04/2006
AEP Generating Co.		

Originator	Project Manager	CI Approval Required by
Clyde L Pries	Thomas R Zelina	05/08/2006

Originator Phone No.	Project Manager Phone No.	Amount to be Authorized
8-220-7715	8-200-1246	$998,700.00
614-583-7715	614-716-1246	

Approved by PMRG Board: Not Reviewed

Date Approved by PMRG Board:

Will material become obsolete as a result of this CI? No

If you have questions concerning Obsolete Material, please contact your Supply Chain Representative.

Budget (Direct Costs)	Prior Years	YR1 2006	YR2 2007	YR3 2008	YR4 2009	YR5+ 2010+	Total
Additions - Plant	0	300,000	0	0	0	0	300,000
Additions - FODA	0	0	0	0	0	0	0
Removal - Plant	0	0	0	0	0	0	0
Removal - FODA	0	0	0	0	0	0	0
Total Direct Budget	0	300,000	0	0	0	0	300,000
Associated O&M	0	0	0	0	0	0	0

Project / CPP / Program Amount Being Authorized

	Prior Years	2006	2007	2008	2009	2010+	Total
Additions - Plant	0	817,000	0	0	0	0	817,000
Additions - FODA	0	100,000	0	0	0	0	100,000
Sub-Totals Additions	0	917,000	0	0	0	0	917,000
Removal - Plant	0	0	0	0	0	0	0
Removal - FODA	0	0	0	0	0	0	0
Sub-Totals Removals	0	0	0	0	0	0	0
Total Direct Costs to be Authorized	0	917,000	0	0	0	0	917,000
Additions - Overheads	0	81,700	0	0	0	0	81,700
Removals - Overheads	0	0	0	0	0	0	0
Overheads	0	81,700	0	0	0	0	81,700

AFUDC	0	0	0	0	0	0	0
Amount Being Authorized	0	998,700	0	0	0	0	998,700
Associated O&M	0	0	0	0	0	0	0
Total Capital	0	998,700	0	0	0	0	998,700
Total Removals	0	0	0	0	0	0	0
Associated O&M	0	0	0	0	0	0	0

Ownership Unit Breakdown

Funding # / Company	*	Prior Years	2006	2007	2008	2009	2010+	Total
RKIMC0652	A	0	499,350	0	0	0	0	499,350
	R	0	0	0	0	0	0	0
Indiana Michigan Power - Gen Total		0	499,350	0	0	0	0	499,350
RKAEG0652	A	0	499,350	0	0	0	0	499,350
	R	0	0	0	0	0	0	0
AEP Generating Co. Total		0	499,350	0	0	0	0	499,350

* A = Additions, R = Removals.

Mark A Gray	05/08/2006 02:16 PM EDT
Mark C McCullough	05/11/2006 12:39 PM EDT
John M McManus	05/11/2006 02:32 PM EDT
William L Sigmon	05/12/2006 04:22 PM EDT

Comments

Clyde L Pries - 05/05/2006 03:24:59 PM
PMRG Board approval not required due to authorization limit.

Attachments

RKIMC0652 PMRGApprovalTemplate9-9-05_000.xls

PROJECT APPROVAL REQUISITION

Company: Indiana Michigan Power **Funding Project Number:** 000009289

Authorization Type: X Capital Improvement ___ Lease Improvement

___ Original Version: 00
X Revision Number: 01

Business Line: Generation

Location: Tanners Creek Unit 4

Project Title: TC U4 PRB Fuel Blend Project Phase 2 & 3 Engineering, Procurement, and Construction

Brief Description: Proceed with final engineering, design, equipment and materials procurement, construction, startup and commissioning to convert Tanners Creek Unit 4 fuel from a 40% PRB blend to an 80% design basis PRB blend, with provisions to stage PRB levels up to 100%. Proceed with environmental permit applications. Perform site investigations and underground explorations.

Project Dates:	Start:	Completion:	Authorization Needed by:
	05/17/04	05/31/06	11/15/04

Expenditure to be Authorized (fully loaded)

	Capital	Removal	Total Cost ($)
Previously Approved Amount	$1,495,533	$0	$1,495,533
This Submission	$89,141,950	$0	$89,141,950
Total ($)	**$90,637,483**	**$0**	**$90,637,483**

Note: Amount to be authorized is the total amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W.	[signature]	1/14/05
$ 10m ≤ amt < $20m	Executive Vice President/COO	Powers, R.	[signature]	1/31/05
$20m ≤ amt < $50m	Chairman, President & CEO	Morris, M. G.	[signature]	1·31/05
amt ≥ $ 50m	Board of Directors	Keane, J.		

CP&B Review	Senior VP	Munczinski, R	John Torpey for REM	1/26/05

Budget Availability for this Authorization: X In Budget ___ Offset

Offset (source & amount):

Generation Only: Submission approved by Project Management Review Group? X Yes ___ No
Nuclear Project Review Group? ___ Yes X No

Comments: ______

IT Project Only: ___ $250,000 ≤ $1,000,000 submission approved by EVP or Delegated to SVP only? ___ Yes ___ No
___ > $1,000,000 submission approved by Office of Chairman? ___ Yes ___ No

PROJECT APPROVAL REQUISITION

Project Expenditure Schedule

Year	2003	2004	2005	2006	2007	Future Years	Total ($)
Capital	$0	$1,673,380	$75,698,229	$13,265,874			$90,637,483
Removal	$0	$0					$0
Amount to be Authorized	$0	$1,673,380	$75,698,229	$13,265,874			$90,637,483
Assoc. O & M	$0	$0					$0

Note: Operating & Maintenance dollars are assumed to be in budget or offset in the year spent.

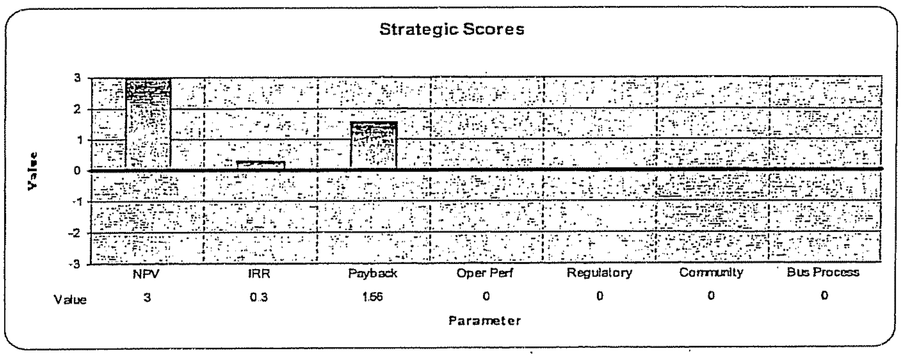
Financial Analysis Summary

Parameter	IRR	NPV	Simple Payback Period	Discount Rate Used
Result	14.5%	$42,400K	6.3 yrs	7.9%

Note: These results must match all background information

Scoring Summary

___ Discretionary _X_ Mandated



Risk Scores	Consequence of not doing project			
		Catastrophic/Severe	Major/Moderate	Minor/ Minimal
Probability	Certain/Probable		S	
	Likely/Possible			
	Rare/Remote			

Risk Type Key: F = Financial, T = Technical, S = Sociopolitical

Please see Project Justification and Glossary for explanation of Scores

Revision 01:
Project Justification & Explanation of Scores

- This revision is requesting funding to proceed with final engineering, design, equipment and materials purchases, permit applications, site investigations, underground explorations, construction, startup and commissioning requested to convert Tanners Creek Unit 4 to an 80% Powder River Basin (PRB) coal blend.
- Based on the results of the Phase 1 engineering, it is estimated that this fuel switch will reduce SO_2 emissions by 21,000 tons per year. Additionally, it will reduce NO_x emissions by 500 tons per Ozone season; particulate emissions will be measurable unaffected due to the low ash content and large precipitator; and fuel costs will be reduced.

Conclusion

- Installation of adequate blending capability to burn 80% PRB coal, and potentially higher PRB blends, at TC4 is recommended, and is part of the overall AEP fleet SO_2 emission optimization plan.
- The Multi-Emissions Compliance Optimization (MECO) computer model has elected to switch to PRB blend at Tanners Creek 4 in all scenarios and sensitivity analyses performed. This project has the advantage of being a relatively "quick" source of SO_2 reductions (within 12 months). In MECO system-wide studies, it is selected in the first year assumed available. The project also provides a positive IRR of 14.5% over 15 years with a simple pay back of 6.3 years.
- This funding request is for Tanners Creek Unit 4. Funding to proceed with detailed engineering, design, equipment and materials purchases, permit applications, site investigations, underground explorations, construction, startup and commissioning is required to support the overall project schedule to commence construction activities in April, 2005 and to complete all work by February, 2006.

Revision 00:
Project Justification & Explanation of Scores

- A computer model, Multi-Emissions Compliance Optimization (MECO), was developed to evaluate fleet emissions compliance. This model identified the Tanners Creek Unit 4 fuel switch as a least cost compliance option based on the projected market and regulatory assumptions along with the estimated project cost.
- In order to meet SO_2 compliance requirements in 2010, funding for a Phase I study is requested to perform preliminary engineering, design, scheduling, and planning to obtain cost estimates to convert Tanners Creek Unit 4 to an 80% Powder River Basin (PRB) coal blend.
- It is estimated that this fuel switch will reduce SO_2 emissions by 25,000 to 30,000 tons per year. Additionally, it will reduce NO_x emissions by 400 to 800 tons per Ozone season; particulate emissions will be measurable unaffected due to the low ash content and large precipitator, and fuel costs will be reduced.
- At the completion of this Phase 1 work, Phase 2 will build upon the conceptual engineering and budgetary cost estimates from Phase 1 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 3 requested labor and material funding.

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 fuel blend project.

- This funding request is for Tanners Creek Unit 4. Funding for Phase 1 engineering, design and environmental assessment for the fuel blend project is required to support development of a Phase 2 CI, to be routed for approval during the fourth quarter of 2004.

Additional Information

Alternatives Considered

- The emissions Compliance Plans have evaluated several alternatives such as the procurement of allowances on the open market and/or SCR and WFGD installations, but these alternatives are more costly.

Regulatory Issues

- Existing regulations under Title IV of the Clean Air Act, as well as regulations currently under development by the U.S. EPA, along with other alternatives to the Clean Air Act being considered by Congress such as Clear Skies and the Carper Bill, will require AEP to reduce emissions of SO_2 in the future. This will trigger the need for installing additional emission control technology on selected plants in the fleet. The U.S. EPA proposed in December 2003 regulation of interstate air quality that, if promulgated, will require significant additional SO_2 and NO_x emission reductions beginning in 2010. The U.S. EPA also proposed in December 2003 regulation of mercury emissions from coal-fired power plants. Mercury emission reductions can be achieved with a combined SCR and FGD system. In addition to these proposed regulations, the existing Title IV acid rain control program will require emission reductions from AEP coal-fired plants prior to 2010 due to the expected decline in the availability of SO_2 emission allowances in the market.

Background Information

- The fuel switch will reduce SO_2 emissions by 25,000 to 30,000 tons per year. Additionally it will reduce NO_x emissions by 400 to 800 tons per Ozone season and will reduce fuel costs.

- A computer model, Multi-Emissions Compliance Optimization (MECO), was developed to guide the selection of methods for fleet compliance under different regulatory scenarios. The model considers power and emission allowance markets, load demand forecast, emission allowance balances, fuel and fuel switching costs, 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 Tanners Creek Unit 4 fuel switch as a least cost compliance option based on the projected market and regulatory assumptions along with the estimated project cost.

Associated / Future Projects

- N/A

Project Contacts

PROJECT APPROVAL REQUISITION

Contact	Name	Telephone
Project Manager	Rodney E. Moore	200-1758
Requisition Detail Provider	Rodney E. Moore	200-1758

Generation Business Unit

AEP® ENVIRONMENTAL PROGRAM

Engineering, Project & Field Services

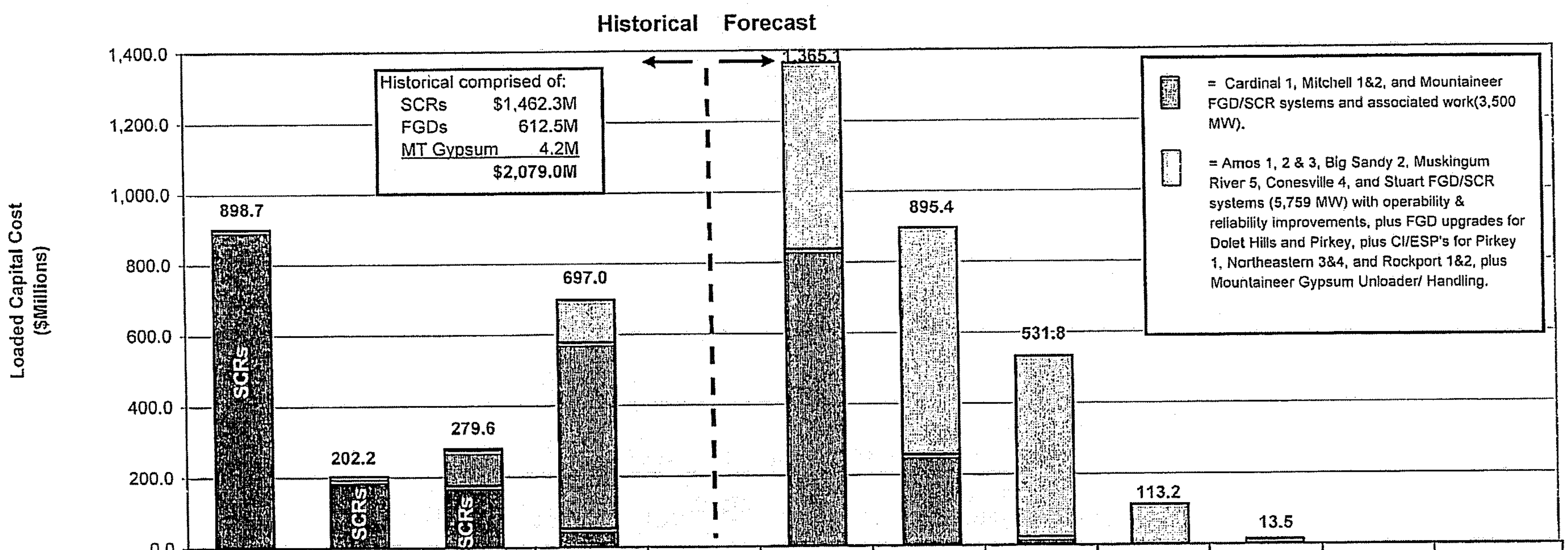
2006-2010 SCR & FGD Long Range Plan – Rev. 6

June 23, 2006

Generation Business Unit

AEP ENVIRONMENTAL PROGRAM

AEP Environmental-Related Capital and Removal Expenditures for SCR and FGD Projects (AEP-Owned Plants)



	1999-2002	2003	2004	2005	Historical Total	2006	2007	2008	2009	2010	2006-2010 Forecast	2004-2010 Environmental Program Total
Tier II CIs	0.0	0.0	3.8	120.4	124.3	528.1	638.1	508.2	113.2	13.5	1,801.1	1,925.3
Tier I CIs	0.0	9.3	100.8	523.5	633.6	837.0	257.3	23.6	0.0	0.0	1,117.9	1,742.2
Total Approved CIs	898.7	192.9	175.0	53.1	1,319.6	0.0	0.0	0.0	0.0	0.0	0.0	228[illegible]
Grand Total All CIs	898.7	202.2	279.6	697.0	2,077.4	1,365.1	895.4	531.8	113.2	13.5	2,919.0	3,895[illegible]

Note: No expenditures for new build or allowances are included in this report. Long Range Plan Rev. 6 is AEP view only; no cash flow is shown for OVEC/IKEC (Kyger and Clifty Creek), Buckeye Power (Cardinal 2 and 3) or CCD portion of Conesville.

Generation Business Unit

AEP

ENVIRONMENTAL PROGRAM

2004-2010 Environmental Program (CapEx Only, Including Overheads and AFUDC)

Plant	Equipment	CI Phase	2004	Long Range Plan 2005	2006	2007	2008	2009	2010	Total
SCR										
In Service Projects	SCR	In-Service	175,069,039	53,135,000	-	-	-	-	-	228,204,039
Mitchell U1	SCR	Phase 3	10,278,843	51,999,021	54,729,080	16,764,479	-	-	-	133,771,424
Mitchell U2	SCR	Phase 3	10,276,302	65,405,942	49,954,094	11,920,455	-	-	-	137,556,793
Conesville U4 @43.5%	SCR	Phase 2	38,101	2,688,276	6,550,786	18,066,499	18,118,834	7,277,080	-	52,739,576
Total SCR's			195,662,285	173,228,239	111,233,960	46,751,433	18,118,834	7,277,080	-	552,271,831
FGD										
Pirkey @85.94%	FGD	Phase 3	176,940	3,880,099	12,032,695	-	-	-	-	16,089,735
Dolet Hills @ 40.23%	FGD	Phase 3	-	-	620,125	437,715	-	-	-	1,057,840
Mountaineer	FGD	Phase 3	31,860,903	122,351,068	200,443,017	6,149,668	-	-	-	360,804,656
Mitchell U1	FGD	Phase 3	21,436,754	106,107,833	89,122,124	26,239,551	-	-	-	242,906,262
Mitchell U2	FGD	Phase 3	20,881,532	104,375,142	92,060,824	18,836,635	-	-	-	236,154,132
Cardinal U1	FGD	Phase 3	5,526,743	35,726,150	89,369,389	79,756,735	6,369,402	-	-	216,746,420
Amos U3	FGD	Phase 3	755,330	29,640,190	134,207,245	131,470,481	54,877,601	-	-	350,950,847
Muskingum River U5	FGD	Phase 2	418,423	11,551,591	59,571,607	121,970,616	83,174,636	-	-	276,686,873
Amos U1 & U2	FGD	Phase 3	857,303	33,876,815	91,481,902	110,654,622	104,763,373	15,833,004	-	357,467,019
Conesville U4 @43.5%	FGD	Phase 2	257,389	3,775,573	13,859,045	37,282,407	44,409,538	12,331,698	-	111,915,649
Big Sandy U2	FGD	Phase 2	-	-	-	-	-	-	13,320,556	13,320,556
Stuart	FGD	Phase 3	-	23,426,000	71,189,000	30,420,000	17,673,500	7,411,560	-	150,120,060
Total FGD's			82,171,318	474,710,462	853,956,973	563,218,429	311,268,050	35,576,262	13,320,556	2,334,222,049
Landfill										
Mountaineer LBR	Landfill		-	7,362,103	11,567,396	10,858,620	11,665,924	-	-	41,454,042
Cardinal U1	Landfill		471,689	455,514	3,309,470	7,224,904	4,241,840	-	-	15,703,417
Amos	Landfill		472,175	1,570,348	12,991,123	10,022,950	8,206,006	12,090,239	-	45,352,841
Muskingum River U5	Landfill		232,806	408,789	4,049,769	8,621,602	15,095,980	-	-	28,408,945
Conesville U4 @ 43.5%	Landfill		64,629	325,515	388,740	182,743	34,987	40,216	165,495	1,202,325
Total Landfills			1,241,299	10,122,268	32,306,497	36,910,818	39,244,738	12,130,456	165,495	132,121,570

Generation Business Unit

AEP

ENVIRONMENTAL PROGRAM

2004-2010 Environmental Program (CapEx Only, Including Overheads and AFUDC)

Plant	Equipment	CI Phase	2004	Long Range Plan 2005	2006	2007	2008	2009	2010	Total
Associated										
Mountaineer	Assoc.	Phase 3	-	17,601,045	99,849,800	17,750,632	-	-	-	135,201,478
Cardinal U1	Assoc.	Phase 3	-	-	16,247,352	51,329,492	1,336,718	-	-	68,913,561
Mitchell U1 & U2	Assoc.	Phase 3	-	12,015,223	130,422,947	10,460,764	-	-	-	152,898,934
Conesville U4 @43.5%	Assoc.	Phase 2	-	431,119	1,682,500	10,156,610	14,051,570	6,918,791		33,240,589
Amos U1 & U2	Assoc.	Phase 3	-	1,751,655	12,890,696	17,551,183	85,587,056	-	-	117,780,589
Amos U3	Assoc.	Phase 3	-	3,623,110	49,606,615	123,909,587	8,475,298	-	-	185,614,610
Muskingum River U5	Assoc.	Phase 2	-	-	2,685,475	17,258,449	19,569,256	-	-	39,513,180
Total Associated			-	35,422,152	313,385,386	248,416,716	129,019,898	6,918,791	-	733,162,942
CI/ESP										
Pirkey 1	ACI/ESP		-	-	-	-	4,880,000	7,320,000	-	12,200,000
Northeastern 3 & 4	ACI/ESP		-			-	7,500,000	11,200,000	-	18,700,000
Rockport 1 & 2	ACI/ESP		-	-	-	-	21,800,000	32,800,000	-	54,600,000
Total CI/ESP's			-	-	-	-	34,180,000	51,320,000	-	85,500,000
Other										
Mountaineer Gypsum Unloader	Other		581,774	1,553,906	10,294,185	7,516	-	-	-	12,437,380
Mountaineer Gypsum Handling	Other		-	1,992,637	43,896,872	41,816	-	-	-	45,931,325
Total Other			581,774	3,546,542	54,191,057	49,332	-	-	-	58,368,705
Grand Total			279,656,676	697,029,663	1,365,073,873	895,346,729	531,831,519	113,222,588	13,486,051	3,895,647,098

Generation Business Unit

AEP®

ENVIRONMENTAL PROGRAM

2006-2010 Long Range (CapEx Only, Including Overheads and AFUDC)

Notes:

1. Based on the March 15, 2006 preliminary P&FS Regulatory MECO model output excluding provisions for CAIR implementation. CAIR needs further analytical evaluation to determine full implementation/compliance requirements. This may result in increased technology deployment.
2. Mercury solutions are preliminary. Carbon injection/ESP's, forecasted at a nominal $21/kw, may be required on additional and/or alternative units. If carbon injection/baghouses are required, overall compliance costs will increase by approximately $120-$140/kw for selected units.
3. Continuing generation optimization efforts related to unit outages may shift cash flow to match generation optimization requirements.
4. Tolerances on scrubber estimates for Muskingum River 5 and Conesville 4 are ±15%, and the Amos 1-3, Mountaineer, Mitchell 1&2 and Cardinal tolerances are +0/-5%.
5. The potential deferral of the MR5 FGD in-service date, including the suspension of all non-essential work, is currently under evaluation.
6. Associated work includes Boiler Modifications, SO_3 Mitigation Systems, Balanced Draft Conversion, Control System Modernizations, Waste Water Treatment and Coal Blending Capability. Tolerances on Associated Work estimates are as depicted in Note 4.
7. Steel and alloy prices escalated substantially in 2004. These increases are reflected in the project cost and a nominal 3% escalation factor for material and field labor has been applied going forward. However, escalation associated with radically changing market conditions and component and labor availability/shortages can not be reasonably predicted at this time. If future unanticipated escalation is incurred, the Long Range Plan will be adjusted accordingly.
8. Cash flows are nominal for a given year and may be re-ordered for optimum construction. Sequencing in later years is for planning purposes only. Individual unit timing may be modified.
9. Total costs reflect the Overhead and AFUDC rates for each Operating Company obtained from Corporate Planning and Budgeting.
10. There are no dollars for plant capacity additions or allowance credits.
11. The impact of natural disaster(s) have not been factored into the cost projections.

Submitted by: Robert L. Walton
Managing Director –Enviro.& Retrofit Projects

Endorsed by: Donald Eng
Don Eng
V.P. – Project & Field Services

Approved by: Michael W. Rencheck
Sr. V.P. – Engineering, Projects & Field Services

Scott N. Smith
V.P. – Generation Business Services

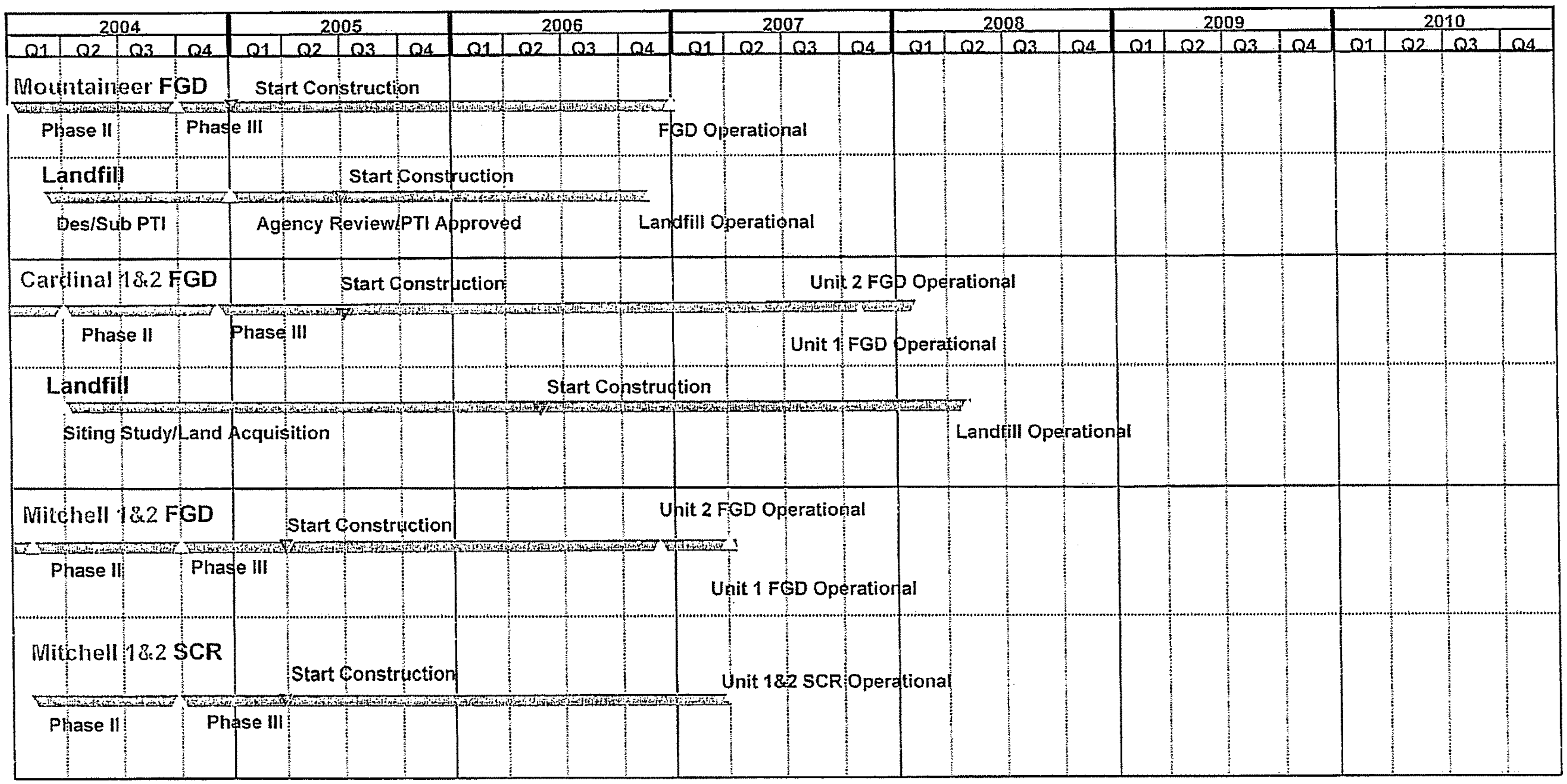
Generation Business Unit

AEP®

ENVIRONMENTAL PROGRAM

Tier 1

Level 1 Schedule



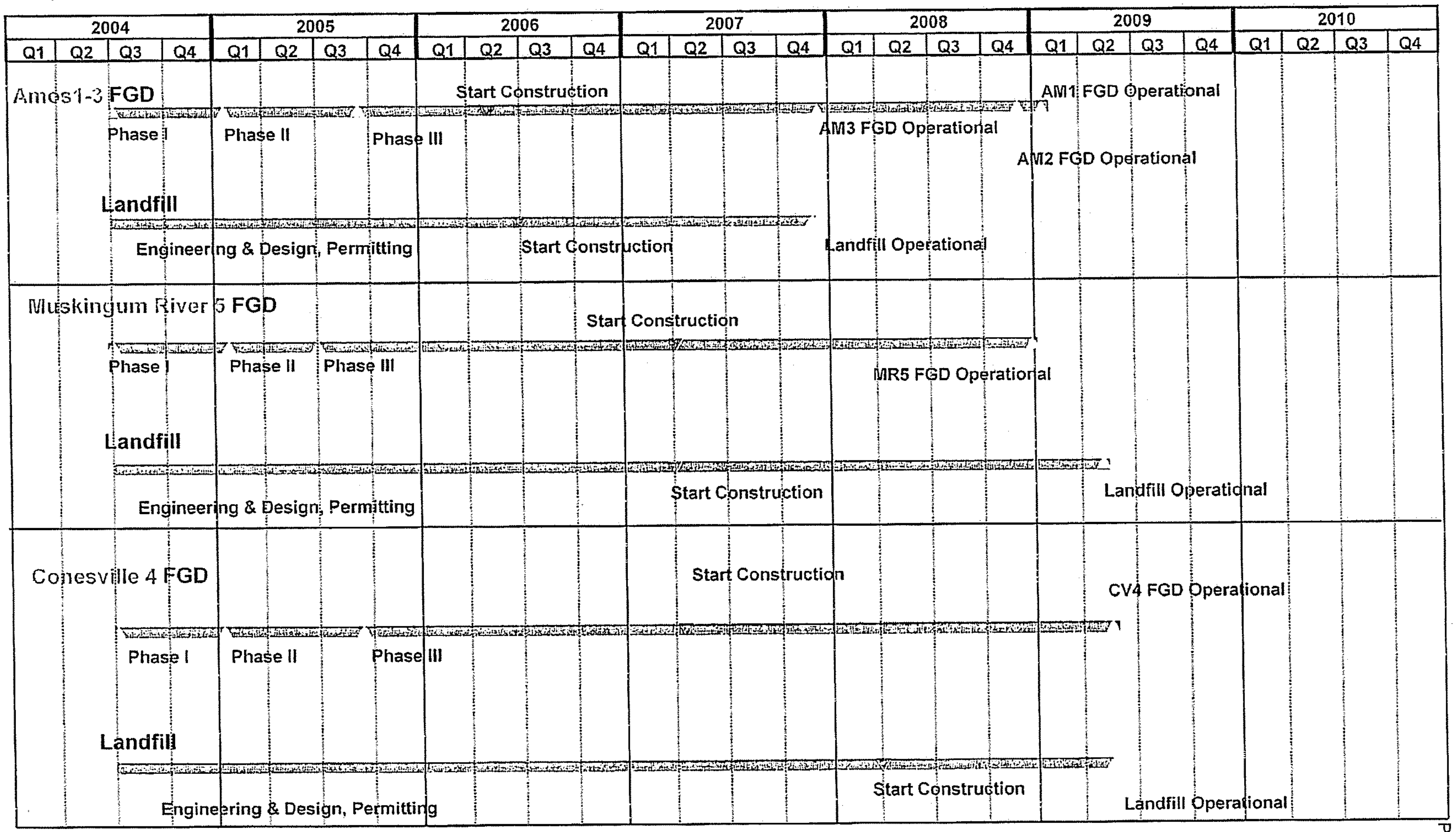
Generation Business Unit

AEP®

ENVIRONMENTAL PROGRAM

Tier 2

Level 1 Schedule



2004-2010 Environmental Program for AEP owned Plants

Long Range Plan Revisions

Plant	December 2005 Rev. 5	Controllable Cost	Non-Controllable Cost	Impact on Forecast	Forecast Rev. 6
SCR					
In Service Projects	228	-	(0)	(0)	228
Mitchell U1	134	0	(0)	(0)	134
Mitchell U2	136	2	0	2	138
Conesville U4 @43.5%	52	0	0	0	53
Total SCR's	550	2	0	2	552
FGD					
Pirkey @85.94%	14	2	0	2	16
Dolet Hills @ 40.23%	4	(3)	(0)	(3)	1
Mountaineer	367	(8)	2	(6)	361
Mitchell U1	230	12	1	13	243
Mitchell U2	226	11	(1)	10	236
Cardinal U1	229	(18)	5	(12)	217
Amos U3	316	36	(0)	35	351
Muskingum River U5	200	62	15	76	277
Amos U1&U2	395	(37)	(1)	(38)	357
Conesville U4 @43.5%	111	(0)	1	1	112
Big Sandy U2	198	(150)	(35)	(185)	13
Stuart	150	-	-	-	150
Total FGD's	2,441	(94)	(13)	(107)	2,334
Landfill					
Mountaineer LBR	39	1	1	3	41
Mitchell Landfill	1	(1)	-	(1)	-
Cardinal U1	19	(4)	1	(3)	16
Amos	42	(1)	4	3	45
Muskingum River U5	24	4	1	5	28
Conesville U4 @ 43.5%	24	(15)	(8)	(23)	1
Big Sandy 2	33	(30)	(3)	(33)	-
Total Landfills	182	(46)	(4)	(50)	132
Associated					
Mountaineer	126	8	1	9	135
Cardinal U1	73	(4)	0	(4)	69
Mitchell U1 & U2	141	12	(0)	12	153
Conesville U4 @43.5%	33	(0)	0	0	33
Amos U1 & U2	156	(40)	1	(38)	118
Amos U3	127	54	5	59	186
Muskingum River U5	60	(20)	(0)	(20)	40
Big Sandy 2	72	(62)	(10)	(72)	-
Total Associated	787	(51)	(3)	(54)	733
ACI/ESP					
Pirkey 1	40	(25)	(3)	(28)	12
Northeastern 3 & 4	-	17	2	19	19
Rockport 1 & 2	78	(20)	(3)	(23)	55
Total ACI/ESP	118	(29)	(4)	(33)	86
Other					
Mountaineer Gypsum Unloader	9	4	0	4	12
Mountaineer Gypsum Handling	41	5	0	5	46
Total Other	50	9	0	9	58
Grand Total	4,128	(209)	(24)	(232)	3,896

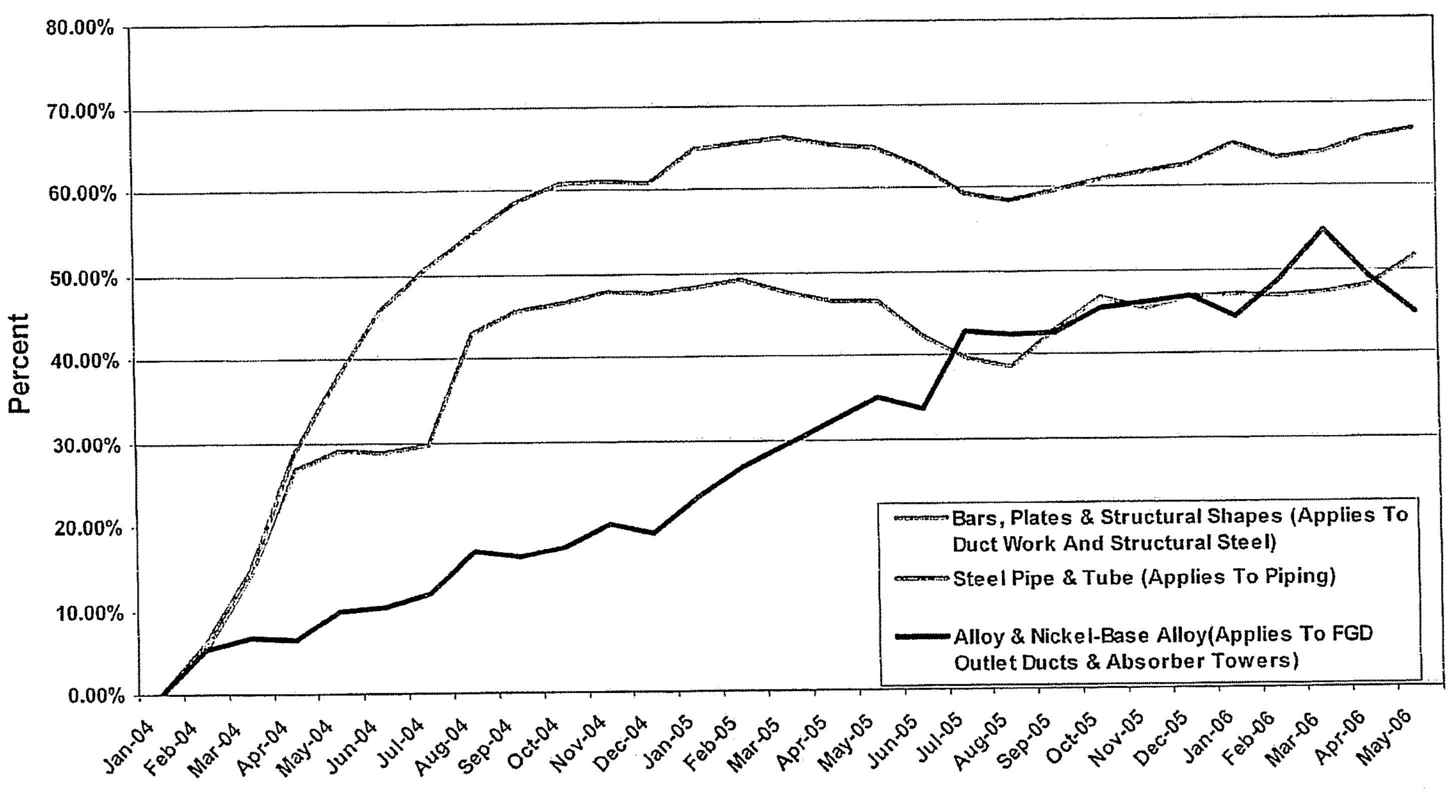
KPSC Case No. 2006-00307
Commission Staff First Set Data Request
Order Dated August 24, 2006
Item No. 4
Page 86 of 173

Generation Business Unit

AEP

ENVIRONMENTAL PROGRAM

Escalation From The Producers Price Index
May 2006



KPSC Case No. 2006-00307
Commission Staff First Set Data Request
Order Dated August 24, 2006
Item No. 4
Page 87 of 173

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	))))	Case No. 04-169-EL-UNC

OPINION AND ORDER

Table of Contents

OPINION AND ORDER

The Commission, having considered the evidence, the arguments of the parties, and the applicable law, hereby issues its opinion and order in this proceeding.

APPEARANCES

Marvin I. Resnik and Sandra K. Williams, 1 Riverside Plaza, Columbus, Ohio 43215-2373, and Daniel Conway, Porter, Wright, Morris & Arthur, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Power Company and Ohio Power Company.

Jim Petro, Attorney General of the state of Ohio, Duane W. Luckey, Senior Deputy Attorney General, by William Wright, Steven Nourse, and Thomas McNamee, Assistant Attorneys General, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Michael R. Smalz, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, and Joseph V. Maskovyak, Legal Aid Society of Columbus, 40 West Gay Street, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

Robert P. Mone, Scott A. Campbell, and Kurt P. Helfrich, Thompson Hine LLP, 10 West Broad Street, Suite 700, Columbus, Ohio 43215-3435, on behalf of Buckeye Power Inc. and Ohio Rural Electric Cooperatives Inc.

Joseph Condo, Calpine Corporation, 250 Parkway Drive, Suite 380, Lincolnshire, Illinois 60069, on behalf of Calpine Corporation.

Stephen J. Smith, Gregory J. Dunn, and Christopher L. Miller, Schottenstein, Zox & Dunn, 41 South High Street, Columbus, Ohio 43215, on behalf of City of Dublin.

Jeanine Amid, City Attorney, and Tom Lindsey, First Assistant City Attorney, 3600 Tremont Road, Upper Arlington, Ohio 43221, on behalf of City of Upper Arlington.

M. Howard Petricoff, W. Jonathan Airey, and Jeffrey Becker, Vorys, Sater, Seymour and Pease LLP, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc.

M. Howard Petricoff, Vorys, Sater, Seymour and Pease LLP, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and Michael D. Smith, Constellation Power Source Inc., 111 Marketplace, Suite 500, Baltimore, Maryland 21202, on behalf of Constellation Power Source Inc.

Evelyn R. Robinson, Green Mountain Energy Company, 5450 Frantz Road, Suite 240, Dublin, Ohio 43016 and Bruce J. Weston, 169 Hubbard Avenue, Columbus, Ohio 43215-1439, on behalf of Green Mountain Energy Company.

Samuel C. Randazzo, Lisa Gatchell McAlister, and Daniel J. Neilsen, McNees Wallace & Nurick LLC, 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users-Ohio.

Michael L. Kurtz, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Ellis Jacobs, Advocates for Basic Legal Equality Inc., 333 West First Street, Suite 500B, Dayton, Ohio 45402, on behalf of Lima/Allen Council on Community Affairs and WSOS Community Action.

Craig G. Goodman and Stacey L. Rantala, National Energy Marketers Association, 3333 K Street NW, Suite 110, Washington, DC 20007, on behalf of National Energy Marketers Association.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, and Colleen L. Mooney, Kimberly J. Bojko, Eric B. Stephens, and Larry Sauer, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential customers of Columbus Power Company and Ohio Power Company.

David F. Boehm and Michael L. Kurtz, Boehm, Kurtz, & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Ohio Hospital Association.

Sally W. Bloomfield and Thomas J. O'Brien, Bricker & Eckler LLP, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Ohio Manufacturers' Association.

David C. Rinebolt, Ohio Partners for Affordable Energy, 337 South Main Street, 4th Floor, Suite 5, P.O. Box 1793, Findlay, Ohio 45839-1793, on behalf of Ohio Partners for Affordable Energy.

Craig A. Glazer and Janine Durand, PJM Interconnection L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497, on behalf of PJM Interconnection L.L.C.

Shawn P. Leyden, 80 Park Plaza, 19th Floor, Newark, New Jersey 07102, on behalf of PSEG Energy Resources and Trade LLC.

Peter J.P. Brickfield and Emily W. Streett, Brickfield, Burchette, Ritts & Stone PC, 1025 Thomas Jefferson Street NW, 8th Floor – West, Washington, DC 20007, on behalf of Wheeling-Pittsburgh Steel Corporation.

OPINION

I. Background

In June 1999, the Ohio General Assembly passed legislation (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly, referred to as SB3) requiring the restructuring of the Ohio electric utility industry and providing for competition for the generation component of electric service. That legislation was signed by the governor in July 1999. Pursuant to SB3, the Commission received and reviewed proposed plans by Columbus Southern Power Company and Ohio Power Company (collectively AEP) to transition from the then-existing regulatory framework to the restructured SB3 framework. *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues,* Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000) and Entry on Rehearing (November 21, 2000).

Ohio electric choice (a short-hand term for the competitive electric generation component in Ohio) began on January 1, 2001. Under Section 4928.40, Revised Code, a period of time was established to allow a competitive electric market to develop for the generation component of electric service (market development period, MDP). The default expiration date of the MDPs was December 31, 2005, unless otherwise determined by the Commission in conformance with certain statutory criteria. Since electric choice began, three competitive retail electric service providers have been certified to serve customers in AEP's service territories, with only one actually serving customers (nonresidential) (Tr. I, 34, 127). There has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). AEP's MDP is currently scheduled to expire on December 31, 2005.

In September 2003, the Commission (while addressing a proposed stipulated plan for the competitive market in The Dayton Power and Light Company service territory) encouraged all other electric distribution utilities (EDUs) in the state to consider continuation of their MDPs, a plan for rate stabilization, and/or a market-based standard service offer as a means for allowing time for their competitive electric markets to grow. *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company,* Case No. 02-2779-EL-ATA, Opinion and Order at 29 (September 2, 2003). Then later that month, the Commission elaborated further that such proposals should balance three objectives: rate certainty, financial stability for the EDU, and further competitive market development. *In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Tariff Adjustments,* Case No. 03-1461-EL-UNC, Entry at 4-5 (September 23, 2003).

On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan (RSP) to follow its competitive electric MDP. AEP proposes a plan to substitute for a post-MDP, market-based standard service offer and to eliminate a competitive bidding process from 2006 through 2008.

Twenty-five entities filed motions to intervene in this proceeding. Those requests were all granted and the intervenors are:

Appalachian People's Action Coalition (APAC)[1]	Buckeye Power Inc.
Calpine Corporation	City of Dublin
City of Upper Arlington	Constellation NewEnergy Inc.[2]
Constellation Power Source Inc.	Green Mountain Energy Company (Green Mountain or GMEC)
Industrial Energy Users-Ohio (IEU-Ohio)	The Kroger Company
Lima/Allen Council on Community Affairs	MidAmerican Energy Company
National Energy Marketers Association (NEMA)	Ohio Consumers' Counsel (OCC)
Ohio Energy Group (OEG)[3]	Ohio Hospital Association
Ohio Manufacturers' Association	Ohio Partners for Affordable Energy (OPAE)
Ohio Rural Electric Cooperatives Inc.	PJM Interconnection L.L.C. (PJM)
PSEG Energy Resources and Trade LLC (PSEG)	Strategic Energy LLC
Wheeling-Pittsburgh Steel Corporation	WPS Energy Services Inc.
WSOS Community Action	

By entry dated March 11, 2004, the Commission established a procedural schedule for this proceeding. A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004. By entry dated April 27, 2004, the examiner slightly modified that procedural schedule, changing deadlines for prefiling expert testimony, discovery cut-off, the local hearing dates (to be held in Canton and Columbus), and the evidentiary hearing date. In May 2004, the parties prefiled their expert testimony under the revised schedule.

Pursuant to the revised schedule, the local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the examiner discovered after that hearing that the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004, and rescheduled the local hearing in Columbus for July 1, 2004.

On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. On May 25, 2004, AEP filed a motion to extend the time to respond to OCC's motion. IEU-Ohio supported an extension of the time to respond to OCC's motion. By

1 Appalachian People's Action Coalition, Lima/Allen Council on Community Affairs, Ohio Partners for Affordable Energy, and WSOS Community Action are collectively referenced in this decision as the low-income advocates or LIA.

2 Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc. are collectively referenced in this decision as the Ohio Marketers Group or OMG.

3 OEG is composed of AK Steel Corporation, BP Products North America Inc., The Procter and Gamble Co., Ford Motor Company, and International Steel Group Inc.

entry dated June 1, 2004, the examiner granted the request to defer a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

The evidentiary hearing began on June 8, 2004, and continued to June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness. At the July 1 and 7, 2004 local hearings, three people provided testimony in opposition to AEP's proposed RSP. The parties filed post-hearing briefs on July 13 and 30, 2004.

II. The Law

Section 4928.14, Revised Code, states in pertinent part:

> (A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified service territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service....
>
> (B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process....At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required in division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

Also relevant, the Commission approved a request filed by AEP to temporarily waive the need for it to propose a market-based standard service offer and/or competitive bidding process (CBP). *In the Matter of the Request for a Temporary Waiver by Columbus Southern Power Company and Ohio Power Company from the Requirements of Chapter 4901:1-35, Ohio Administrative Code*, Case No. 04-888-EL-UNC, Entry (June 23, 2004). The Commission agreed that AEP need not make such proposal(s) until 30 days after the final order is issued in this proceeding.

III. Certain Elements of the Approved Electric Transition Plan

In moving to electric choice in Ohio, the Commission had to address a number of financial and regulatory concerns so that each of the electric utilities could transition into utilities providing monopoly distribution service, while competing to provide the generation component. In the course of making that transition, the bundled rates and services of the electric utilities had to be separated, or unbundled, into generation, distribution and transmission components in the electric transition plan (ETP) proceedings.

Most of the parties to the AEP ETP proceedings agreed upon a resolution of the issues. The Commission reviewed that proposed resolution and approved it, with some minor modifications and with a reservation of a ruling upon the independent transmission plan. For purposes of better understanding the proposed RSP, several relevant components of the ETP are:

(1) All distribution rates effective December 31, 2005 will be frozen through 2007 for Ohio Power and 2008 for Columbus Southern. However, during that period, distribution rates can adjust to reflect costs of complying with certain changes (e.g., environmental, tax and regulatory changes) and for relief from storm damage or emergencies.

(2) Columbus Southern and Ohio Power agreed to absorb the first $20 million of actual consumer education, customer choice implementation and transition plan filing costs, but the remainder of such were permitted to be deferred, plus a carrying charge, as regulatory assets for recovery in future distribution rates (via a rider).

(3) Regulatory asset recovery was approved for the companies' MDP and for the subsequent three years for Columbus Southern and the subsequent two years for Ohio Power. Recorded regulatory assets at the beginning of the MDP, which exceeded specific regulatory asset dollar amounts in the stipulation, were amortized during the MDP and recovered through existing frozen and unbundled rates.

(4) Columbus Southern made available to the first 25 percent of the switching residential customers a shopping incentive. Any unused portion of that incentive as of December 31, 2005, will be credited to Columbus Southern's regulatory transition cost recovery.

(5) AEP reduced by five percent its generation component (including the regulatory transition costs). AEP agreed to not seek to reduce that five percent reduction for residential customers during the MDP. The first 20 percent of Ohio Power residential customer load as of December 31, 2005, that switches will not be charged the regulatory transition charge in 2006 and 2007.

(6) AEP shall transfer, by no later than December 15, 2001, operational control of its transmission facilities to a Federal Energy Regulatory Commission (FERC) approved regional transmission organization (RTO). AEP established a fund (up to $10 million) for costs associated with transmission charges imposed by PJM and/or the Midwest

Independent System Operator (MISO) on generation originating in the service territories of PJM or MISO as such costs may be incurred.

IV. Elements of the Proposed Rate Stabilization Plan

AEP proposes a plan from 2006 through 2008 to substitute for a post-MDP market-based standard service offer and to eliminate a competitive bidding process (Tr. I, 27). The RSP states that all provisions of the approved ETP that are not changed by the RSP will not be changed. The RSP proposal can be quickly summarized as follows:

(1) Keeps distribution rates in effect on December 31, 2005, frozen through 2008, except for changes allowed by 12 categories.

(2) Continues to defer pre-2006 consumer education, customer choice implementation and transition plan filing expenses beyond $20 million. Defer post-2005 consumer education, customer choice implementation and transition plan filing expenses and all RSP filing costs. All will be recovered as distribution regulatory assets, along with carrying charges, after the RSP.

(3) Allows deferral and recovery in RSP distribution rates of: (a) RTO administrative charges from the date of integration in PJM through 2005, along with a carrying cost; (b) full carrying charges for construction expenses in Accounts 101 (electric plant in service) and 106 (completed construction not classified) from 2002 through 2005; and (c) 2004 and 2005 equity carrying charges for expenditures from 2002 through 2005 in Account 107 (construction work in progress).

(4) Increases generation rates for all customer classes by three percent for Columbus Southern and seven percent for Ohio Power each year of the plan. Also, generation rates can be adjusted in the event that any of five situations arise, but the sum of the generation increases shall not be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any one of the years. As an alternative to the increases for residential customers, AEP offers that the Commission can terminate the five percent residential generation rate discount on June 30, 2004 (which will, instead, increase generation rates for residential customers by 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power each year of the plan). These generation rate increases are avoidable for customers who choose another competitive generation supplier.

(5) Allows adjustments of transmission components for changes in costs directly or indirectly imposed on the companies during the RSP.

(6) Recovers amortized generation-related transition regulatory assets under the ETP rates.

(7) Makes the Columbus Southern 2.5 mills per kilowatt-hour (kWh) shopping incentive available during the RSP to the first 25 percent of the Columbus Southern residential load. Any unused portion will not be credited to the regulatory asset charge, but will become income to Columbus Southern. Still for 2006 and 2007, the first 20 percent of Ohio Power residential load that switches will not be charged the regulatory asset charge.

(8) Includes other terms addressing post-RSP Commission action, functional separation, an allowance for AEP to participate in the CBPs of other companies, and minimum stay requirements for all categories of customers.

AEP provided estimated revenue amounts expected from the fixed generation rate increases and the new deferrals to be recovered during the RSP (AEP Ex. 3, at 10):

Company	2006	2007	2008	Total
Columbus Southern	$48 million	$74 million	$100 million	$222 million
Ohio Power	$112 million	176 million	$247 million	$535 million

If the potential four percent generation increase were also added to the calculation, AEP acknowledges that the total estimated revenue amount combined for both companies becomes $1.17 billion (Tr. II, 78).

V. OCC's Motion to Dismiss

As noted earlier, OCC filed, on May 24, 2004, a motion to dismiss the application in this proceeding on two grounds, namely that the application will violate several statutes and it illegally proposes to repudiate the ETP stipulation. In the context of describing the various components of the RSP, we will also explain and address the legal and policy arguments raised by the parties, including the specific arguments made by OCC.

VI. Positions of the Intervening Parties and Commission Discussion

Of the parties who have expressed a position in this proceeding, nearly all agree that a competitive market has not adequately developed in AEP's service territories (AEP Ex. 1, at 4; AEP Ex. 2, at 24; Tr. I, 201; Staff Ex. 2, at 3; Tr. IV, 151; OEG Ex. 2, at 5; Tr. III, 208; GMEC Initial Br. 2, 5; IEU-Ohio Initial Br. 8-10; LIA Reply Br. 2, 9). Moreover, many also believe that some action needs to be taken by the Commission to avoid a "flash-cut" in 2006 to a freely competitive electric generation market (OEG Ex. 2, at 5; Tr. III, 208; 7/7/04 Tr. 6-7, 9; IEU-Ohio Reply Br. 7). Some of these parties openly fear that, without some Commission action, generation rates will escalate and fluctuate dramatically, which could hurt consumers, hurt the development of a competitive market, and harm the market participants (AEP Ex. 1, at 4; Staff Ex. 2, at 7; Staff Initial Br. 1, 12). The disagreement here is over the specific approach that the Commission should take to spur competition in AEP's service territories, while balancing the interests of the different market participants. As already noted, the Commission has determined that the objectives of an RSP are to develop a plan providing for: rate certainty, financial stability for the EDU, and further competitive market development.

A. Market-Based Standard Service Offer and Competitive Bidding Process

AEP has not conducted any studies or surveyed the market to determine the impact of its RSP upon shopping or participation by competitive suppliers (Tr. II, 177; GMEC Ex. 2). However, AEP believes that the proposed rate increases will create some opportunity for increased shopping (Tr. II, 178). Staff also agreed (Tr. IV, 23, 243-244). Moreover in AEP's view, its RSP will cover AEP's need to spend approximately $1.3 billion on environmental controls after 2005 and address AEP's environmental expenditures of roughly $1.0 billion between 2002 and 2004 (AEP Ex. 3, at 8, 11; Tr. I, 234-235). Additionally, AEP states that the RSP addresses transmission expenses, customer switching and future uncertainty (AEP Initial Br. 11). It is for those reasons that AEP believes its RSP is a reasonable proposal and good substitute for a market-based standard service offer and CBP.

AEP's RSP contains no CBP; instead, AEP seeks to substitute its RSP for a CBP. AEP takes the position that a CBP is not practical and not worth the effort (Tr. I, 96-97, 104-105). As noted earlier, the Commission has waived, temporarily, the current requirement for the filing of a CBP while the proposed RSP is under consideration. AEP believes that its proposed increased generation rates are reasonable substitutes for market-based rates. In AEP's view, if the market exceeds those rates, customers will benefit by having a fixed rate and, if the market rates fall below the increase levels, customers can avoid them by switching to another supplier (AEP Initial Br. 23, 65-66). Staff concurs that the generation rates constitute a reasonable proxy of market-based rates because of prices in the current wholesale market, prices in AEP's area, and shopping levels (Tr. IV, 20-21, 26-27, 244; Staff Initial Br. 4, 6). Moreover, staff believes that a next step (RSP) that provides generation rate stability and gradual, predictable increases is the best approach (Staff Reply Br. 3).

OEG and IEU-Ohio agree with the Commission's stated objectives and the concept of an RSP. However, neither agrees with AEP's RSP. Instead, they each advocate that their own proposed rate plan be adopted by the Commission (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18; IEU-Ohio Initial Br. 6, 14, 37-40). OEG's rate plan basically provides: (a) no new transmission and distribution deferrals beyond that authorized in the ETP decision; (b) no transmission and distribution increases except for costs to comply with environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, or an emergency; (c) transmission and distribution rate increases after 2005 only upon a fully evaluated rate case; and (d) fixed generation rate increases after 2005 through a monthly rider designed to recover incremental environmental and governmentally mandated costs that have passed an earnings test (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18). OEG's plan also addresses allowed components of rate base, components of operating expenses and rate of return (OEG Initial Br. 23-26).[4] OEG considers its plan to appropriately balance several things: (a) new environmental and

4 Green Mountain disagrees with OEG's proposed RSP because the increases are cost-based, not market-based (GMEC Reply Br. 6).

generation-related costs are balanced with timely recovery, while the rates increase to reasonable levels based upon earned returns; (b) allows gradual and steady monthly rate increases when needed for financial stability; (c) ensures market development through moderate generation rate increases; and (d) ensures that earned returns do not increase through piecemeal, single-issue, distribution rate increases (*Id.* at 18; OEG Reply Br. 23-24).

IEU-Ohio recommends various modifications to AEP's RSP that focus upon the price certainty and financial stability objectives identified by the Commission (IEU-Ohio Initial Br. 38-40). In particular, IEU-Ohio recommends that: (a) AEP establish its standard service offer prices as the current generation charge[5] of each rate schedule; (b) AEP continue to collect transition costs; and (c) AEP be permitted to seek adjustment of the current generation charges (either as confiscatory or as requiring increases due to increased jurisdictional costs from fuel prices, environmental actions, tax laws, or judicial/administrative orders).[6] In the alternative, IEU-Ohio urges the Commission to consider extending and lowering the current fixed rates, as was found to be acceptable in Virginia (IEU-Ohio Reply Br. 11). AEP responds to both OEG's and IEU-Ohio's proposed plans, stating among other things that those parties simply want to keep AEP's low rates for another period of time and their plans do not take into account all three Commission goals (AEP Reply Br. 14, 25-26).

OCC argues that AEP's proposed RSP does not meet the requirements of Sections 4928.02 or 4928.14, Revised Code, because the RSP is not a market-based standard service offer and/or a CBP (OCC Motion to Dismiss 3-4, 11; OCC Initial Br. 35-36; OCC Reply Br. 22). Thus, in OCC's view, the Commission has no authority to approve the RSP. Similarly, OCC argues that the generation rate component of the RSP is improper because it contains no CBP, as required by Section 4928.14(B), Revised Code (OCC Initial Br. 35). Also, OCC contends that, since the RSP addresses service during the MDP that conflicts with the approved ETP, it violates Section 4928.33(C), Revised Code (OCC Motion to Dismiss 12). OMG, NEMA, PSEG, Green Mountain, and LIA concur with these criticisms (OMG/NEMA Initial Br. 2-6, 15; OMG/NEMA Reply Br. 3-5; PSEG Br. 3-4, 8-9; GMEC Initial Br. 6; GMEC Reply Br. 4; LIA Initial Br. 9-11). In their view, the RSP cannot be an acceptable substitute because it is not based on market prices. OCC, OMG and NEMA acknowledge that the RSP was proposed as an alternative to the market-based standard service offer, but argue that, legally, an alternative cannot be substituted because the statute does not allow for such (OCC Initial Br. 38; OMG/NEMA Initial Br. 5-6; OMG/NEMA Reply Br. 4-5). LIA and Green Mountain state that, instead of illegally seeking RSP proposals, the Commission should have followed the path set forth in Section 4928.06, Revised Code, and provided an evaluation to the legislature (LIA Initial Br. 12-14; LIA Reply Br. 8; GMEC Reply Br. 6). OCC recommends that a CBP be filed as soon as

---

5 In IEU-Ohio's proposal, it references the "little g" instead of current generation charges. When AEP's rates were unbundled prior to the start of electric choice, the amounts that were categorized as generation-related (or the "big G") were the amounts not distribution-related, transmission-related, other unbundled amounts, and tax valuation adjustments. Section 4928.34(A)(4). Revised Code. For AEP, the "little g" is the difference between the "big G" and the amounts allotted for the regulatory transition charge. The "little g" is what is reflected in AEP's charges as the current generation charges.

6 Green Mountain also disagrees with IEU-Ohio's proposed RSP because the MDP rates are not market-based rates (GMEC Reply Br. 5).

possible and recommends a particular format (OCC Ex. 10, at 10, Attach. A; OCC Reply Br. 24-25).

PSEG and OEG argue that the Commission's goals for a RSP are not fulfilled by AEP's proposal. Specifically, PSEG states that rate certainty is not assured because of the many exceptions that are contained in the RSP for possible future events (PSEG Br. 6). OEG states that rate stability is not included in the RSP because the $1.17 billion potential increase cannot constitute stability (OEG Initial Br. 5). Next, they both contend that the RSP really just provides financial stability to AEP and PSEG believes it will benefit AEP's competitive activities, rather than financial stability of its regulated functions (PSEG Br. 7; OEG Initial Br. 5). Moreover, PSEG claims that the RSP will do nothing to foster development of the competitive electric market (PSGE Br. 8). OCC quantifies the impact on the residential class for some of the costs over the three years as $266 million if the additional generation increase is not included and $410 million if it is included (OCC Ex. 5, at 3-4, Schedule FRP-1). OCC recommends that the entire RSP be rejected (OCC Initial Br. 64)

If the RSP is not rejected for failure to use market-based rates, OMG, NEMA and PSEG recommend that the Commission require a competitive bid to test the market (as it did with the FirstEnergy EDUs) and establish a basis for that market's prices (OMG/NEMA Reply Br. 6-8, 11; PSEG Br. 9).[7] Moreover, OMG and NEMA point out that, pursuant to Section 4928.14(B), Revised Code, AEP must either provide for a competitively bid generation service or demonstrate that such would be duplicative to available services. They argue that AEP cannot make such a demonstration and, therefore, a CBP must be scheduled like the Commission has done with other EDUs (OMG/NEMA Reply Br. 8-9). If the Commission decides to require a CBP, Green Mountain advocates a retail CBP (bidding for customers) as done in Pennsylvania, instead of a wholesale CBP (bidding to provide generation) (GMEC Reply Br. 10-12). IEU-Ohio took the opposite position, stating that providing customers with a CBP in the current state of the market would elevate form over substance (IEU-Ohio Initial Br. 40). Instead, IEU-Ohio believes the Commission should ask the legislature to delay the CBP option until the Commission concludes that the market is sufficiently mature to warrant the time and resources needed for CBPs (*Id.*).

<u>Commission Discussion</u>

At the outset, we will note that AEP proposed an RSP because we requested it. All parties to this proceeding are aware of the direction that this Commission has taken and the concerns it has with the post-MDP competitive electric environment. In fact, many of

7 The Commission ordered a CBP for the FirstEnergy EDUs in *In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period,* Case No. 03-2144-EL-ATA (June 9, 2004). On December 8, 2004, the CBP took place (an auction). The Commission concluded, on December 9, 2004, that the CBP auction price should be rejected because the previously approved RSP price is more favorable for consumers than the clearing price of the auction, which represented the best available market-based price to cover FirstEnergy's retail load. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Competitive Bid Process to Bid Out Their Retail Electric Load,* Case No. 04-1371-EL-ATA, Finding and Order.

the parties in this proceeding have participated in several other proceedings involving the MDPs and post-MDP activities for other EDUs. Many of the parties readily acknowledge that a competitive electric generation market has not developed thus far in AEP's service territories and will not adequately develop by the time AEP's MDP expires in December 2005. With so few participants, so very little shopping having taken place in Columbus Southern's territory and no shopping at all having taken place in Ohio Power's territory, we do not want to simply allow market forces to be unfettered. We believe, in AEP's territory, a controlled transition is not only appropriate, but very much needed. We also believe that many, if not all parties, agree with this fundamental starting point.

The difference of opinion occurs with the manner in which to handle the near term. OCC, OMG, NEMA and LIA argue that Section 4928.14, Revised Code, provides the only mechanisms available to the Commission (adoption of a market-based standard service offer and a service developed through a CBP) and the proposed RSP is neither. Even with those two mechanisms identified in Section 4928.14, Revised Code, the parties disagree what should be done. However, AEP, staff, OEG and IEU-Ohio believe greater flexibility is available, namely, the Commission can adopt an RSP. We agree. AEP takes the position that a CBP is not practical and not worth the effort. Staff and IEU-Ohio agreed. We also agree and, as is within our authority, we conclude that a CBP is not warranted for AEP at the conclusion of its MDP. The record reflects that, in the past several years, only three competitive suppliers have been certified to provide competitive electric service in AEP's territory and only one is actually serving customers (Tr. I, 34, 127). Plus, there has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). This level of inactivity leads us to seriously doubt the efficacy of initiating a competitive bid. Instead, we conclude that an RSP (and in particular the one we adopt today) will accomplish, generally, the same as a CBP for customers and provide a reasonable means for customers to participate in that competitive environment as it continues to develop. As further explained in this decision, we agree to increase generation rates (which are avoidable to customers who choose another competitive generation supplier). These components of the RSP, along with continuation of the unaffected provisions of the ETP, we believe will prompt the competitive market and continue to provide customers a reasonable means for customer participation. Therefore, we conclude that, at this time, a CBP is not required for AEP between 2006 and 2008.

Many parties argue that AEP's proposed RSP is not a market-based standard service offer because it is not based upon the market. OMA and NEMA have argued that the RSP is not based upon a willing buyer and a willing seller. AEP proposes its RSP as a substitute for a market-based standard service offer (Plan at 3). Staff presented evidence that the RSP is a reasonable proxy of market-based rates based upon its evaluation (Tr. IV, 20-21, 26-27, 244). OCC's witness acknowledged that the Commission has the discretion to determine an appropriate proxy for a market-based standard service offer, given that both the retail electric choice market and the wholesale market have not sufficiently developed (Tr. III, 147). For the period involved (2006 through 2008), we conclude that the generation rates that we approve in this RSP today will constitute an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code. We will evaluate any subsequent, additional generation rate adjustments (which are limited to only the enumerated categories). Additionally, we conclude that the RSP that we approve today complies with the requirements of Section 4928.14, Revised Code. None of the arguments raised to the contrary convinces us otherwise. Finally, we note that there is greater flexibility under Section 4928.14, Revised Code, than what some parties have advocated in this proceeding. The Ohio Supreme Court recently recognized, in *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, ____ Ohio St.3d ___, 2004-Ohio-6767 (December 17, 2004), that an RSP could satisfy Section 4928.14, Revised Code.

Next, we conclude that our decision today will fulfill our previously identified RSP goals. Throughout this decision, as we address the various components of the proposed RSP, we specifically explain how and why we believe that various approved components are acceptable, including how they meet or fulfill our intended goals.

B. Generation Rates and Charges (Provisions Two and Three of the RSP)

1. Three and Seven Percent Increases

AEP proposes in the RSP that, for all customer classes, the generation rates will increase each year (2006, 2007, and 2008) by three percent for Columbus Southern and by seven percent for Ohio Power. These increases will generate $151 million for Columbus Southern and $376 million for Ohio Power (AEP Ex. 3, at 10). AEP contends that the three and seven percent generation rate increases are reasonable to address the Commission's three objectives of a RSP. These generation rate increases are based upon the companies' judgment (AEP Ex. 2, at 12). Given that AEP has low generation rates currently, AEP contends that fixed increases will spur market competition and be preferable to customers, rather than imposition of full market-based rates (*Id.* at 13). AEP further notes that the generation rate increases complement the companies' substantial investments to comply with environmental requirements. AEP noted that it plans to spend $1.3 billion beyond normal capital expenditures after 2005 on generation-related environmental controls (AEP Ex. 2, at 14; AEP Ex. 3, at 11). Next, AEP points to other EDU generation rates and contends that its increased rates would still be below the current lowest average residential generation rates of those EDUs (AEP Ex. 5, at 13; Tr. III, 31).[8] When that comparison is made, AEP argues that its proposed generation rate increases are reasonable (AEP Ex. 5, 13; AEP Initial Br. 24, 67-68).

Staff supports the fixed generation rate increases as reasonable in magnitude and because they are completely avoidable if a competitor can beat the price and customers shop (Staff Ex. 2, at 8; Tr. IV, 152, 154-155, 163-164, 248-249; Staff Reply Br. 4). Staff evaluated this portion of the plan in the context of the current market, the expectation that generation rates will rise and the magnitude of the proposed numbers for company financial integrity (Tr. IV 156, 158; Staff Ex. 2, at 8). Moreover, staff noted that AEP's rates are low compared to the Ohio market and keeping them frozen would impede supplier entry in the territory (Tr. IV, 248).

8 Staff notes that AEP is distinguishable from other EDUs in Ohio because it has lower cost generation supplies and has an infrastructure to allow it to move power within a seven-state region (Staff Initial Br. 4). Staff suggests that AEP's proposal here should be evaluated separately from the other RSPs (*Id.*).

OEG, Green Mountain, LIA, OCC, and IEU-Ohio disagree with the proposed fixed, generation rate increases. OEG and IEU-Ohio object to the three and seven percent generation rate increases on the ground that they will generate excessive earnings, while AEP has been already receiving very healthy returns (OEG Ex. 2, at 14-16; OEG Reply Br. 4, 6; IEU-Ohio Initial Br. 7). OEG contends that the fixed generation increases will engender 3.6 times more revenues than the companies' projected costs for the environmental expenditures identified (OEG Ex. 2, at 15). OEG and OCC are also skeptical that customers will really avoid the increased generation rates on the ground that the market is defective now and even AEP anticipates that it will remain defective for a period of time (OEG Reply Br. 22-23; OCC Reply Br. 20). Thus, in OEG's and OCC's view, customers will only have an option to shop in a defective market or take generation service from AEP at increasing rates (*Id.*). Moreover, OCC highlights that the identified projected costs for the environmental expenditures are not costs just for these companies; rather, they will be allocated throughout the entire AEP system, but AEP did not account for such allocation (Tr. I, 79; OCC Ex. 10, at 8; OCC Initial Br. 28). AEP and staff respond that, after the MDP, generation service is no longer subject to cost-based regulation and, thus, AEP's generation rates and charges need not be cost-based (AEP Initial Br. 31; Staff Initial Br. 4; Tr. IV, 154, 158, 165-166, 245). OEG counters by noting that AEP justified many aspects of the proposed RSP by relying solely on the cost of service for those items (e.g., additional generation-related expenses to be recovered through generation rate increases and deferrals) (OEG Reply Br. 17-18).

Green Mountain argues that the RSP's rates are below market (GMEC Initital Br. 8). Green Mountain further argues that AEP should be required to prove the cost basis of its generation rates (and distribution and transmission rates) since AEP has justified its RSP by pointing to various costs/expenses and Section 4905.33(B), Revised Code, prohibits service for less than actual cost for purposes of destroying competition (*Id.* at 18).

IEU-Ohio contends that justification for the fixed generation rate increases is weak because it is not clear that AEP will spend all estimated amounts on environmental compliance, the estimated expenditures only modestly affect production costs during the RSP period, and those expenditures will be allocated among the various operating companies as production costs (Tr. I, 58-60; IEU-Ohio Initial Br. 5-6). IEU-Ohio points out that the proposed fixed generation rate increases will allow AEP to collect $527 million more than current generation rates allow, in addition to the $702 million in transition costs allowed under the ETP decision (IEU-Ohio Initial Br. 3). IEU-Ohio points out that this RSP asks the Commission to approve generation rate increases on the basis that the current generation rates are below market, while in 1999, AEP claimed that the generation component was at above-market prices and, therefore, asked for regulatory transition costs (IEU-Ohio Initial Br. 17-18, 22; IEU-Ohio Reply Br. 7).

IEU-Ohio acknowledges that electric generation service (after the MDP) shall not be subject to traditional cost-of-service supervision or regulation, but it also believes that the Commission has a duty to ensure that the standard service offer prices are just and reasonable (IEU-Ohio Initial Br. 25-29; IEU-Ohio Reply Br. 3-5). In IEU-Ohio's view, the RSP's proposed generation rates are too high and not reasonable, particularly since AEP's financial condition has been very favorable over the last few years. Next, IEU-Ohio contends that these rate increases will simply fund investments and growth on earnings and are not necessary for financial stability (IEU-Ohio Initial Br. 30-31). IEU-Ohio also noted that, in Virginia, price caps have been extended and Ohio should realize that raising retail prices in Ohio (while other states extend rate caps) will not benefit Ohio as it strives to compete in the global economy (IEU-Ohio Reply Br. 8).

OCC argues that this portion of the RSP violates Section 4928.38, Revised Code, because it seeks recovery of additional generation-related costs not authorized in the ETP at the time when AEP is supposed to be on its own with respect to recovery of generation-related costs (OCC Motion to Dismiss 5). OCC further argues that these fixed generation rate increases are not cost-based or justified because a complete picture of current costs has not been made (some prior costs may no longer exist, while some new costs and benefits have developed) (Tr. I, 173-174, 222; OCC Initial Br. 28-31; OCC Reply Br. 16, 17). OCC supports OEG's estimated rates of return and argues that they demonstrate that the fixed generation rate increases alone will cause extremely high returns for AEP that should not be permitted (OCC Initial Br. 32, 39; OCC Reply Br. 16-17). In other words, OCC states that AEP should not be earning higher returns on equity than they could possibly be allowed in a regulatory environment when a developed competitive market is absent (*Id.* at 39).

LIA also disagrees with the generation rate increases in the RSP (LIA Initial Br. 16). On legal grounds, LIA argues that, since the RSP involves an increase in rates, AEP has violated Sections 4909.17 and 4909.19, Revised Code, by not following rate increase procedures (*Id.* at 9). Moreover, LIA contends that AEP's actions/inactions regarding RTO membership have caused a competitive market to not develop and, therefore, AEP does not have "clean hands" and should not be rewarded with excessive increases in rates (LIA Reply Br. 2). From a public policy perspective, LIA contends that the companies already have high profit margins and do not need rate increases, and yet do not propose any programs to mitigate the impact of the RSP on low-income customers (LIA Initial Br. 16, 20, 31; LIA Reply Br. 3-4, 6). LIA notes that AEP is the only Ohio utility to ever terminate funding for low-income energy efficiency programs (APAC Ex. 1, at 7; Tr. IV, 182; LIA Initial Br. 32). LIA further contends that the RSP will exacerbate the already high amounts of percentage of income payment plan (PIPP) arrearages for AEP customers (*Id.* at 26). If the Commission proceeds with an RSP, LIA and OCC argue the Commission must consider the impact of the RSP on the low-income consumers and vulnerable populations in order to promote rate stability and certainty (*Id.* at 20, 34; OCC Initial Br. 62). Specifically, LIA urges: (a) the Commission to allow PIPP customer pools to participate in CBPs during the RSP; (b) AEP to negotiate with the Ohio Department of Development, Commission staff, and low-income intervenors to develop "an approach to arrearages that reinforces good payment behavior by PIPP program participants and reduces the PIPP debt to a manageable level that can conceivably be repaid"; and (c) the Commission require funding by AEP of $1.5 million per year for a low-income energy efficiency program in AEP's service territory (APAC Ex. 1, at 8, 12; Tr. IV, 197, 201; LIA Initial Br. 29, 32; LIA Reply Br. 7-8). OCC supports these three recommendations (OCC Initial Br. 62).

Commission Discussion

Certainly, to some extent, the generation rate increases will provide additional funds to the companies and assist in their financial stability. As noted, AEP will be incurring large generation-related expenses above normal capital expenditure levels during the RSP period. However, we also believe that the RSP package as a whole supports our goals of helping to develop the competitive market and providing some rate stability. We reach this conclusion because we believe that the generation rate increases are a reasonable approximation of the future market conditions. With the RSP's structured, periodic generation rate increases, customers will not be subjected to significant swings in generation rates in an emerging competitive market for AEP. We believe this provision is not only very important to spurring a competitive market, but also to protecting customers from the risks and dangers associated with price volatility and a nascent competitive market.

We also accept our staff's conclusion that the percentage increases are reasonable in magnitude. Many of the parties object to this provision because they contend that AEP is already earning too much. However, these parties seem to forget that, with the expiration of the MDP, generation rates are subject to the market (not the Commission's traditional cost-of-service rate regulation) and that the plan was an option that AEP voluntarily proposed. Section 4928.05(A)(1), Revised Code. We make this observation to point out that, under the statutory scheme, company earnings levels would not come into play for establishing generation rates - market tolerances would otherwise dictate, just as AEP argued (AEP Reply Br. 26-27). We are strongly committed to encouraging the competitive market in AEP's service territories as it is the policy of this state, per Section 4928.02, Revised Code. Given that commitment, we do not feel that the earnings levels evidence or cost-based analyses and arguments presented by OEG, OCC, IEU-Ohio or LIA justify rejection of this provision. We believe that this provision will establish generation rates that are appropriate for the RSP period, spur the competitive market, and also protect customers from dramatic or volatile generation rate price changes. We do not agree that this provision violates any of the cited statutes.

While we have found the proposed generation rate increases to be reasonable, both in concept and in number, it is also appropriate to point out that these increases will be avoidable during the rate stabilization period. Customers who choose another competitive generation supplier can avoid AEP's increased generation rates (because those customers will pay, instead, the rates of their chosen supplier). We believe this is an important point to note.

We do realize that rate increases can be difficult for some customers to handle, as LIA has argued. We are not ignoring these concerns. In fact, we believe that the structured nature of the generation rate increases will be more helpful to the low-income customers in AEP's territory than would otherwise likely occur without the RSP. Ideally, we agree that rate increases are not preferred, but we are weighing and balancing several competing interests and we believe that the proposed generation rate increases will result in the most balanced and reasonable generation rates for all customers in AEP's service territories during the three years following the MDP. For these additional reasons, we accept this provision. Despite that conclusion, we agree that low-income customers, in particular, can be disproportionately affected by the RSP. To alleviate that concern, we conclude that low-income customers should receive some additional assistance. Therefore, we have provided for additional funding of low-income and economic development programs during the RSP period as set forth in Section VI.G of this decision.

2. Elimination of Five Percent Residential Discount

For all residential customers, AEP proposes an additional generation rate increase each year of 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power, if the five percent generation discount terminates on June 30, 2004. This would end the five percent residential rate reduction 18 months earlier than what was agreed upon in the ETP stipulation (Tr. I, 28). If elimination of the five percent discount to residential customers is included, AEP calculates that the generation rate increases will be 8.5 percent for Columbus Southern residential customer and 13.2 percent for Ohio Power residential customers in 2006 (AEP Ex. 2, at 11). This would amount to roughly a $6 million increase for residential rates (Tr. I, 29). AEP supports this proposal by noting that Section 4928.40(C), Revised Code, allows the Commission to terminate the discount if it is "unduly discouraging market entry by [...] alternative suppliers." Despite the proposed June 30, 2004 date having passed, AEP has noted that the alternative is still viable, but the later termination of the discount (still prior to the end of the MDP) will result in reduced fixed increases for residential customers (AEP Initial Br. at footnote 11). AEP, staff and Green Mountain believe that the current generation rates, along with the existing temporary discount, unduly discourages market entry because of the small price differential between AEP's generation rates and others' generation supplies (AEP Ex. 2, at 12; Tr. IV, 23; GMEC Br. at 16-17). Staff and Green Mountain urge the Commission to eliminate the temporary discount (Staff Ex. 2, at 9; GMEC Initial Br. 17).

OCC opposes elimination of the five percent discount on the ground that the ETP stipulation requires the companies to retain the discount for residential customers through the MDP (OCC Initial Br. 32; OCC Reply Br. 17).[9] The ETP stipulation states that the companies will "not seek to reduce the [five percent] reduction in the generation component rate reduction for residential customers during the market development period" (OCC Ex. 1, at 6). OCC also contends that AEP has not demonstrated that the discount is unduly discouraging market entry, as required by Section 4928.40(C), Revised Code (OCC Ex. 10, at 5; OCC Reply Br. 18). In fact, AEP could not say that elimination of the discount would result in suppliers entering the residential market (AEP Ex. 2, at 12; Tr. I, 137-138). AEP contends that its RSP does not ask to remove the five percent discount during the MDP; it only noted that it was an option that the Commission could consider in the context of the RSP's proposed generation rate increases (AEP Initial Br. 27-28, 68, 78).

IEU-Ohio states that the Commission should consider elimination of AEP's five percent residential discount in a "stand-alone" proceeding that is "focused on the

9 OCC argues that the Commission lacks authority to approve any portion of the RSP that impacts any term in the ETP decision (OCC Motion to Dismiss 2; OCC Initial Br. 2-3). Staff disagrees with that argument because the Commission retains ongoing jurisdiction over its orders, including the authority to change or modify its earlier decisions as it deems necessary in the best interests of the utility and customers (Staff Initial Br. at footnote 1).

residential customer sector and the full range of conditions that are affecting market entry by alternate suppliers" (IEU-Ohio Initial Br. 41).

Commission Discussion

OCC correctly cites the ETP stipulation. We also believe that AEP's argument that its RSP does not ask to remove the five percent discount is an attempt at "hair-splitting". AEP's RSP proposed eliminating the five percent discount and it previously agreed that it would not make such a request during the MDP.

Notwithstanding the language in the ETP stipulation and our acceptance of that stipulation, we have the ability to evaluate the impact of the five percent residential discount under Section 4928.40(C), Revised Code. Section 4928.40(C), Revised Code, gives the Commission the flexibility to eliminate the five percent residential discount if it unduly discourages market entry in AEP's service territories. We believe that an early ending to the discount is not warranted and, rather, it is appropriate that the five percent residential discount in both companies' territories, end effective December 31, 2005. We further note that ending the five percent residential discount on December 31, 2005, is in keeping with SB3 (including Section 4928.40, Revised Code) and is consistent with the timing required of the residential discounts of four other EDUs. *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 24-25 and *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period*, Case No. 03-93-EL-ATA, Opinion and Order at 36-37 (September 29, 2004).

3. Additional Generation Rate Increases

AEP's RSP allows generation rates to further increase, after a Commission hearing, for: (a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes, and new generation-related regulatory requirements imposed by statute/rule/ regulation/administrative order/court order; or (b) customer load switches that materially jeopardize either company's ability to recover the anticipated generation revenues. Total generation rate increases cannot be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any given year (if the five percent residential discount is not eliminated).[10] The additional generation adjustments are effectively capped at four percent. The RSP proposes a 90-day time frame, after which the proposed increase will become effective on an interim basis until the Commission's final order is implemented.

AEP points out that this aspect of the RSP only gives the company the flexibility to ask for additional, limited generation rate increases in the event of changes in the two enumerated categories; it does not pre-approve or guarantee rate increases (AEP Ex. 2, 16-

10 If the five percent residential discount would have been eliminated as of June 30, 2004, any additional generation rate increases would be at most four percent above the residential customers' fixed annual increase, which would be at most 5.6 percent for Columbus Southern residential customers and 9.7 percent for Ohio Power residential customers (AEP Ex. 2, at 18).

17; AEP Initial Br. 35). AEP characterizes this provision as a means to manage the risk it faces relative to the fixed generation rate increases (AEP Reply Br. 28). At this point in time, AEP does not expect to ask for additional rate increases (Tr. I, 198). Also, AEP mentions that any additional increases that might be authorized by the Commission could be avoided for customers who choose another competitive supplier (AEP Initial Br. 35).

Staff, Green Mountain and IEU-Ohio do not fully support or fully object to this provision. They believe that any request for additional generation rate increases should be evaluated by looking at the company's overall financial health (not just the events that triggered the proposed further increase) and not be limited to four percent (Staff Ex. 2, at 9-10; GMEC Reply Br. 12-13; IEU-Ohio Initial Br. 42; Tr. IV, 33, 153, 231, 245). Staff recognizes that the proposed additional generation increases would be sought for many of the same reasons that AEP had based its proposed three and seven percent increases and, thus, believes automatic additional increases should only be considered after looking at the whole company (Tr. IV, 153, 245-247). AEP responded by stating that a look at the overall financial health of the company is contrary to Section 4928.05(A)(1), Revised Code, because generation pricing will not be subject to cost-of-service ratemaking principles (AEP Initial Br. 38). Additionally, AEP predicts that holding generation rates down because of a strong "wires business" is likely to result in rate shock in 2009, which is what the Commission is trying to avoid today (*Id.*; Tr. I, 247).

OCC argues that the proposed four percent additional increase does not result from changes in market prices and, thus, is not market-based (OCC Ex. 10, at 9). Like staff, OCC characterizes this provision as improper single-issue ratemaking and also criticizes the ambiguity of the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues" (*Id.*).

OEG worries that this portion of the RSP could permit recovery twice for the same expenses; essentially that the same costs used to justify the fixed increases arguably could justify the proposed additional increases (OEG Ex. 2, at 16-17). Plus, because the companies will continue to have very high earnings, OEG believes that the additional generation rate increases are not needed to maintain financial stability (OEG Initial Br. 8). AEP notes that this criticism is really a concern over the Commission's ability to judge any proposed additional generate rate increase and not a sufficient basis for rejecting this portion of the RSP (AEP Initial Br. 39).

<u>Commission Discussion</u>

We find this portion of the RSP to be acceptable. We agree with AEP that this portion of the RSP will allow AEP to seek additional generation rate increases; it does not pre-approve them (although it does limit any approved amount). We understand staff's and IEU-Ohio's preference that subsequent generation rate increases be viewed in the context of the company's overall financial health, but that position ignores the requirements of Section 4928.05(A)(1), Revised Code. Thus, we find this portion of the RSP to appropriately temper potentially large generation rate increases (by limiting the dollar amounts), while also recognizing AEP's interest in financial stability. This provision is a compromise position that takes into consideration the competing interests. We understand the criticism raised with the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues." In the event that further increases are requested by AEP, we will evaluate this. Similarly, we understand OEG's concern that AEP could request further generation-related rate increases for items that it is already recovering. But, as AEP states, the concern does not justify rejecting the provision; it is really a question of whether the proposed further increase is properly evaluated. For these reasons, none of the comments raised in this proceeding convinces us that this portion of the RSP should be rejected.

C. Distribution Rates and Charges (Provision One of the RSP)

Under the RSP, AEP distribution rates and charges in effect on December 31, 2005, would remain in effect through 2008 (except for the universal service fund rider, energy efficiency fund rider, and certain cost-based charges such as right-of-way charges). These "frozen" distribution charges could be also adjusted in the event of an emergency, changes in transmission/distribution allocations under the FERC's seven-factor test, or if the companies experience increased distribution-related expenses due to: (a) changes in laws/rules/regulations related to environmental requirements; (b) security; (c) taxes; (d) O&M due to new requirements imposed by federal or state legislative or regulatory bodies after March 31, 2004; and (e) major storm damage service restoration. Furthermore, the "frozen" distribution rates will be adjusted, if the Commission approves, to recover certain deferred RTO administrative costs (deferred in 2004 and 2005) plus carrying costs and certain deferred carrying costs on certain environmental expenditures since 2002, plus carrying costs.

AEP points out that the RSP only freezes distribution rates for an additional one-year period for Ohio Power, because the ETP froze them previously (AEP Ex. 2, at 5). AEP acknowledges that, in addition to what is contained within the ETP, the RSP would add some additional categories for which the "frozen" distribution rates would/could be adjusted (*Id.*; Tr. I, 31-32). AEP contends that, at least with the proposed adjustments for security expenses and the specified O&M expenses, they are justified because of the unforeseen security issues that previously developed and the likelihood that O&M expenditures will be needed since the ETP was approved (AEP Ex. 2, at 6).

Staff, IEU-Ohio and OEG state that a distribution rate case should be conducted, instead of freezing distribution charges from 2006 to 2008 (Staff Ex. 2, at 7-8; Tr. IV, 230; IEU-Ohio Initial Br. 42; OEG Ex. 2, at 22-23). They reach this conclusion because these distribution rates were established in 1991 and 1994 rate cases (Staff Ex. 2, at 8). More specifically, OEG believes that AEP's returns on common equity have been very high over the last several years and the proposed RSP will only perpetuate them (OEG Ex. 2, at 11-14). AEP took issue with OEG's rate of return calculations, alleging a number of errors (AEP Initial Br. 31-35).

OCC also opposes this provision. OCC contends that the additional exceptions to the distribution rate freeze (security and O&M expenses) are unwarranted (OCC Ex. 10, at 6). In OCC's view, AEP accepted the risk that increasesd expenses for these two items would occur when it signed the ETP stipulation and AEP should not now be permitted to illegally attempt to modify the ETP or violate Sections 4909.18 and 4909.19, Revised Code

(OCC Ex. 10, at 6-7; OCC Motion to Dismiss at 9).[11] Moreover, OCC contends that these exceptions to the distribution rate freeze constitute single-issue ratemaking, which is not appropriate public policy because the exceptions do not recognize other cost-related changes (OCC Ex. 10, at 6-7; Tr. III, 187-188). In response, AEP states that OCC's position conflicts with its position that the Commission set a post-MDP generation rate at something other than market levels (AEP Initial Br. 14).

LIA disagrees with the distribution rate provision in the RSP because it will also allow rate increases (LIA Initial Br. 16).

Commission Discussion

We find that Provision One of the RSP is acceptable. The additional exceptions to the distribution rate freeze are, in the context of considering the RSP as a package, reasonable. We understand OCC's contention that the additional exceptions to the rate freeze can be considered single-issue ratemaking, but we also must point out that OCC previously agreed to other exceptions to the distribution rate freeze, which can also be considered single-issue ratemaking. The next question then is whether the additional exceptions are justified. We do accept AEP's contention that, in 1999 and 2000, security expenses and the specified O&M expenses were not fully foreseeable. In this respect, we believe that allowing for these additional exceptions to the distribution rate freeze during the RSP is acceptable. We view the extension of the distribution rate freeze as a positive aspect of the RSP, which meets our goal of fostering a competitive market and still balancing rate stability with financial certainty for AEP.

We appreciate the position taken by staff, IEU-Ohio and OEG about the need for a distribution rate case. They have correctly noted that a rate proceeding has not taken place for either company for a period of time. AEP believes that, after the RSP, it would be appropriate for the Commission to initiate rate proceedings (Tr. I, 102). AEP explained that a rate proceeding at this point would frustrate the Commission's goals of rate stability and financial stability over the next few years (*Id.*). We agree that embarking on a rate proceeding at this point could run counter to our ultimate goals. Therefore, we do not accept that position.

D. Deferral Requests (Provisions One, Five and Six of the RSP)

The companies propose to defer the costs of several items during the RSP (AEP Ex. 2, at 8-9; AEP Ex. 4, at 4-6, 10-12). These items are:

(a) RTO administrative charges (adjusted for net congestion costs) from the time of integration into PJM[12] through 2005, plus a carrying charge (based on the weighted average cost of capital).

(b) The 2004 and 2005 equity carrying charges on expenditures begun in 2002 through 2005 for expenditures located in Account 107, construction work in process (CWIP).

---

[11] OCC contends that, after the MDP, EDU distribution rates can only be adjusted through properly filed applications under Chapter 4909, Revised Code (OCC Motion to Dismiss 10).

[12] AEP integrated into PJM on October 1, 2004.

(c) The full carrying charges (based on the weighted average cost of capital) on expenditures begun in 2002 through 2005 for all functions in Accounts 101 (electric plant in service) and 106 (completed construction not classified), except line extension expenditures, which are already subject to carrying cost deferrals.

(d) Consumer education, customer choice implementation, and transition plan filings through 2005, plus a carrying charge.

(e) Consumer education, customer choice implementation, and transition plan filing costs incurred after 2005, and all RSP filing costs, plus a carrying charge.

Most of the expenditures in the second and third categories are associated with environmental control equipment (nitrogen oxide burners, flue gas desulphurization, and selective catalytic reduction) for generation facilities (Tr. II, 14-18; OCC Ex. 3). AEP estimated the total amounts of these proposed deferrals over the RSP as follows (AEP Ex. 4, at 3, 6-7; AEP Ex. 3, at 4-5, 7; AEP Ex. 2, at 8):

Proposed Deferral	Columbus Southern	Ohio Power
RTO Admin. Costs[13]	$11.9 million	$15.6 million
RTO Admin. Costs Carrying Costs	2.5 million	3.2 million[14]
CWIP Carrying Costs	1.0 million	9.0 million
In-Service Plant Carrying Costs	13.0 million	50.0 million
Addl. Carrying Costs for CWIP and		
In-Service Plant	2.0 million	9.0 million[15]
Pre-2006 Education, Choice		
Impl. and Transition Plan		
Filing Costs[16]	40.6 million	45.5 million
Post-2005 Education, Choice		
Impl., Transition Plan Filing		
and all RSP Filing Costs[17]	18.2 million	19.7 million
Total	$89.2 million	$152 million

13 These estimates do not include an adjustment for congestion costs, as those are unknown (AEP Ex. 3, at 3; AEP Ex. 2, at 8).

14 AEP's estimate of the RTO administrative costs totaled $14.4 million for Columbus Southern and $18.8 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $48 million for Columbus Southern and $60 million for Ohio Power (AEP Ex. 3, at 7, 10). However, we note that AEP's brief reflects instead that the anticipated revenues to be produced by this aspect of the RSP will be $16.8 million for Columbus Southern and $20.7 million for Ohio Power (AEP Initial Br. Attachment A at 3 and Attachment B at 3).

15 AEP's estimates of the carrying costs of the CWIP and in-service plant totaled $16 million for Columbus Southern and $68 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $23 million for Columbus Southern and $99 million for Ohio Power (AEP Ex. 3, at 7, 10).

16 These estimates were made by AEP in May 2000 (OCC Ex. 1, at 4). They do not include carrying charges. No updated estimates were presented as evidence in this proceeding.

17 The companies did not estimate RSP filing costs (AEP Ex. 3, at 5).

In AEP's view, these are new, significant costs that cannot be capitalized and were not built into current rates (AEP Ex. 4, at 7). It should be noted, however, that AEP would amortize these new deferrals over the three-year RSP and begin recovering those amounts as regulatory assets through distribution charges in 2006, except for the consumer education, customer choice implementation, transition plan filing costs incurred, and all RSP filing costs, plus a carrying charge (AEP Ex. 2, at 21; AEP Ex. 4, at 4).

1. Regional Transmission Organization Administrative Costs

Staff calculated an average of the RTO deferral rider to be .27 mills/kWh for both companies and found it to be a reasonable level for what it considers to be a new service (Tr. IV, 63-64, 67-68, 112, 253). OMG and NEMA do not fully object to this proposed deferral, but contend that recovery of it during the RSP will cause some shopping customers to be charged twice for those same costs (OMG/NEMA Initial Br. 9-11). OCC also agrees with this criticism, but still otherwise objects to the deferral, as detailed further below (OCC Initial Br. 8-9; OCC Reply Br. 8). More specifically, OMG and NEMA explain that any shopping customer will pay the pre-2006 RTO administrative charges to his/her generation supplier as part of the cost of receiving that generation supply and, then, also pay AEP when it assesses the deferral during the RSP. OMG and NEMA state that an easy solution is to require that AEP customers who shop after October 1, 2004, get a credit for PJM administrative charges until the end of the MDP, but impose the deferrals upon them during the RSP (OMG/NEMA Initial Br. 11-12). Green Mountain agrees (GMEC Reply Br. 9). AEP responds to this suggestion, stating that it is impossible to segregate how much each customer's bill will recover the deferral and, thus, the suggestion is not possible (AEP Reply Br. 19-20).

OCC objects to the RTO administrative cost deferral for several other reasons. OCC first contends that this proposed deferral should be rejected because it violates the intent of the distribution service rate cap (set forth in Section 4928.34(A)(6), Revised Code); it is simply an attempt to recover costs that were to be recovered by the capped distribution rates (OCC Ex. 10, at 7; OCC Initial Br. 5-6, 9; OCC Reply Br. 2-3; OCC Motion to Dismiss 7). OCC also considers this provision to violate the part of the ETP decision which freezes distribution rates beyond the MDP. OCC points out that a utility can recover transmission costs through an increase to the transmission component, which will correspondingly decrease the distribution component during the MDP (OCC Initial Br. at 6). AEP even acknowledged this possibility (Tr. I, 171). Second, OCC argues that AEP is proposing single-issue ratemaking contrary to Chapter 4909, Revised Code (OCC Initial Br. 7; OCC Reply Br. 12-13). OCC does not believe that the Commission should consider this single ($33.2 million) charge in isolation of overall transmission rates.

OCC next contends that the proposed deferral of the RTO administrative charges would improperly allow AEP to recover transmission-related expenses through nonbypassable distribution rates (OCC Reply Br. 7-8). AEP acknowledges that the RTO administrative charges are transmission-rated (AEP Ex. 2, at 7; AEP Ex. 4, at 16; Tr. I, 240). However, AEP contends that these costs benefit all customers (switching and non-switching customers) because all customers benefit with AEP's participation in an RTO. AEP explains that the only means to allocate cost recovery among all customers in a competitively neutral fashion is a nonbypassable distribution charge (AEP Ex. 2, at 7; AEP Ex. 4, at 18). AEP also explained that, without the requested authority or FERC authority, the RTO administrative charges would not be recovered (Tr. I, 237). Moreover, AEP stated that, while the RTO administrative costs could be recovered via a change in state transmission charges (and thereby reduce distribution rates), AEP would effectively not be able to recover those transmission expenses (Tr. I, 238). Finally, in OCC's view, it "strains credibility that the companies did not know there would be RTO administrative costs when they agreed to join an RTO in the ETP stipulation" (OCC Initial Br. 10). OCC also does not consider the RTO administrative costs to be a new service, as staff indicated, or rate stabilization charges. OCC believes these are MDP-incurred transmission charges proposed to be recovered through a distribution rider after the MDP (*Id.*).

LIA argues that a deferral of the pre-2006 RTO administrative costs is tantamount to an increase in the MDP-capped distribution rates (LIA Initial Br. 4, 6). LIA states that Section 4928.38, Revised Code, prohibits the creation of new deferrals associated with distribution service construction, and Section 4928.34(A)(6), Revised Code, and the ETP decision are also violated (*Id.* at 5, 7). In LIA's view, this deferral constitutes a "back door" attempt to raise distribution rates, regardless of when the deferral is collected (*Id.* at 6).

OEG contends that the RTO administrative cost deferral proposes to adjust frozen distribution rate under circumstances not permitted by the ETP decision (OEG Initial Br. 13). OEG also believes that the effect of the deferral request is to avoid a rebalancing of transmission and distribution rate levels, which is required by Section 4928.34(A)(1), Revised Code, to remain at the MDP levels (*Id.*). Next, OEG takes issue with the dollar amounts in this proposed deferral for two reasons. OEG points out that AEP does not plan to recognize, in the amount of RTO administrative deferrals, the benefit that AEP will receive from making additional off-system sales as a member of PJM (Tr. I, 173). Further, OEG highlights that these administrative costs will include costs related to the companies' efforts to participate in the MISO (Tr. I, 248; OEG Initial Br. 14).

IEU-Ohio states that these RTO administrative costs were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that the proposed deferral should be denied. IEU-Ohio also noted that, in July 2004, an AEP affiliate in Virginia agreed to forego recovery of RTO administrative costs, certain congestion costs, and ancillary service cost increases, except through a base rate case (IEU-Ohio Reply Br. 7-8, Attachment). That affiliate also agreed to not seek to defer such Virginia-specific costs. Furthermore, that affiliate agreed to not seek to recover development and implementation costs that were then being deferred, other than through a base rate case. IEU-Ohio makes the point that other treatment of RTO administrative costs has been agreeable to an AEP company.

Commission Discussion

The RTO administrative charges involved in this proposed deferral will be charges incurred from October 2004 through 2005. We do not believe that this proposed deferral is a rate increase. Accord, *Consumers' Counsel v. Pub. Util. Comm.* (1983), 6 Ohio St.3d 377. Recovery of the deferred RTO administrative charges would be based upon accruals during AEP's MDP. As a result, we will not approve the proposed deferral of 2004 and 2005 RTO administrative charges.

The Commission recognizes that AEP's expenditures for RTO membership during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its provider of last resort (POLR) responsibilities during the rate stabilization period. AEP is required to provide that function after the MDP. Section 4928.14(A) and (B), Revised Code. The Commission has also recognized in other cases that the POLR responsibility of the EDU is one for which the EDU incurs necessary costs and which warrants compensation during rate stabilization periods. See, *Dayton, supra* at 28, and *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 23-24. The Supreme Court of Ohio recently upheld an earlier Commission conclusion that the existence of POLR costs makes it reasonable to apply a charge to customers during a RSP period. *Constellation, supra.* Our staff also made this argument in this proceeding (but in relation to the CWIP and in-service plant deferrals). We believe the proposed RTO administrative charge amounts for collection during the rate stabilization period constitute reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. This POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

We reach this conclusion based upon the specific circumstances before us in this proceeding. Nothing in this decision is intended to be precedent-setting or to be construed as ruling upon the other RTO charge-related deferral requests that we have recently received from other EDUs. See, *In the Matter of the Application of The Dayton Power and Light Company for Authority to Modify its Accounting Procedures*, Case No. 04-1645-EL-AAM, and *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company to Modify their Accounting Procedures*, Case No. 04-1931-EL-AAM.

2. Carrying Costs of Construction Work in Progress and In-Service Plant Expenditures

Staff supports the CWIP and in-service plant deferrals as well (Staff Ex. 2, at 11). Staff considers such deferrals to be equivalent to POLR charges (Tr. IV, 108-109, 147, 148, 171). Staff reaches this conclusion because the RSP is providing an option to switch and avoid charges for AEP customers and creating a risk for AEP that customers will switch, for which it is reasonable, in staff's view, for AEP to collect POLR charges (Tr. IV, 149-150). AEP concurs that these costs function as POLR costs (AEP Initial Br. 47, 79; AEP Reply Br. 16). Moreover, staff noted that, when compared to similar charges proposed by other EDUs, staff felt that AEP's proposed levels were reasonable (*Id.*). Staff calculated the amounts per kWh to be .38 mills for Columbus Southern and 1.16 mills for Ohio Power, for an average of .84 mills (Tr. IV, 108-109). Staff also stated that allowing AEP to recover a part of what it would be able to obtain under traditional regulatory process when competition has not really arrived is reasonable (Staff Ex. 2, at 11). Staff further acknowledges that, if these costs are allowed as rate stabilization charges, it is fair for the charges to be bypassable (that is to say, a customer who chooses another supplier and is not returning would not be subject to the charge while purchasing another's generation) (Tr. IV, 254-255).

OCC objects to this portion of the RSP for a host of reasons. OCC argues that, if these generation-related deferrals are permitted for recovery after the MDP, then the rate freeze is meaningless (OCC Initial Br. at 14, 51; OCC Reply Br. 2-3). OCC believes that, after the MDP, new distribution deferrals are not permitted under Ohio law because distribution rates are subject to rate regulation under Chapter 4909, Revised Code (OCC Initial Br. 14-15, 52). Additionally, OCC contends that AEP assumed the risk of these expenditures when it agreed to freeze distribution rates in the ETP proceeding (*Id.* at 15, 17-19). OCC points to OEG's evidence that AEP does not need the deferrals to provide financial stability. OCC also claims that distribution rates should not be increased to recover generation costs, per the ETP decision and Sections 4928.15, 4928.17(A), 4928.34(A)(6) and 4928.38, Revised Code (*Id.* at 15-16; OCC Motion to Dismiss 8; OCC Reply Br. 10-11). Like the RTO administrative costs, OCC contends that the Commission should not approve these single-issue ratemaking deferrals without looking at the full picture and because shopping customers will then pay a portion of AEP's generation costs even though they will be taking generation service from a competitor (OCC Initial Br. 15, 22; OCC Reply Br. 12-13).

OEG and OCC argue that these deferrals constitute retroactive ratemaking (a rate increase during the MDP) because the deferral relates to amounts in existence prior to the date of the decision in this case (OEG Ex. 2, at 18-19; OCC Initial Br. 17-19). Also, OEG and LIA contend that these two deferrals take away one of the primary incentives of implementing electric choice in Ohio (a cap on distribution rates during the MDP) contrary to Section 4928.34(A)(6), Revised Code (OEG Initial Br. 9-11; LIA Initial Br. 4). Further, OEG, LIA and OCC believe these deferrals violate the ETP decision because they are generation-related expenses used to adjust distribution rates during the period allowed by the ETP decision for frozen distribution rates (LIA Initial Br. 5, 7; OEG Initial Br. 12-13; OCC Initial Br. 16). AEP disagrees, noting that the Commission has allowed deferrals for periods that precede the date of a decision (AEP Initial Br. 46). Also, AEP argues that accounting deferrals are not rate increases and, thus, cannot constitute retroactive ratemaking (*Id.*; AEP Initial Br. 70; AEP Reply Br. 17).

OEG also argues that these deferrals do not recover distribution-related costs and should not be deferred for recovery in distribution charges (OEG Ex. 2, at 20-22). AEP agrees that these deferrals are not recovering distribution costs and, thus, argues that the distribution rate freeze cannot preclude them (AEP Initial Br. 47). In AEP's and staff's view, recovery of these deferrals will function as POLR charges, not distribution service charges (*Id.*; AEP Reply Br. 16; Tr. IV, 108, 147).

Green Mountain has a different point of view. It argues that generation-related increases should not be as limited as set forth in the RSP (GMEC Initial Br. 15-16). Instead, Green Mountain contends that any generation-related costs that AEP seeks to recover should be included in generation rates. However, if the Commission accepts another recovery mechanism (such as the proposed deferrals), then the established recovery mechanism should be bypassable (*Id.*; GMEC Reply Br. 9).

IEU-Ohio states that these CWIP and in-service plant expenditures were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that these proposed deferrals should be denied.

Commission Discussion

Similar to our reasoning for the RTO administrative charges, we do not believe that this proposed deferral is a rate increase. However, recovery of the deferred CWIP and in-service plant carrying charges would be based upon accruals during AEP's MDP. The Commission recognizes that AEP's expenditures for CWIP and in-service plant during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its POLR responsibilities during the rate stabilization period, which warrants compensation during rate stabilization period. Section 4928.14(A) and (B), Revised Code, requires AEP to provide that function after the MDP. We believe these carrying charge amounts proposed for collection during the rate stabilization period constitute a reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. As noted earlier, this POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

3. Consumer Education, Customer Choice Implementation, Transition Plan Filing Costs, and all Rate Stabilization Plan Filing Costs

Staff supports this deferral provision (Staff Ex. 2, at 10). IEU-Ohio does not believe that the Commission needs to address most of this deferral because it was already addressed in the ETP decision (IEU-Ohio Initial Br. 43). Also, IEU-Ohio does not believe that the Commission should authorize increases for isolated categories of costs, even if expected (*Id.* at 44). OCC argues that, aside from the agreement in the ETP decision to allow some of these deferrals, the Commission should reject additional deferrals in this case (OCC Initial Br. at 52). OCC reaches this conclusion because new distribution deferrals and rate riders for single issues have no basis in Ohio law; the Commission can only adjust regulated distribution rates through a properly filed rate case.

Commission Discussion

We already allowed deferral for most of the costs in this category (in the ETP proceeding). This RSP provision would further defer those costs and also allow deferral of the RSP filing costs. In the context of considering the RSP package and our stated RSP goals, we are willing to accept this provision of AEP's plan.

E. Transmission Rates and Charges (Provision Four of the RSP)

This part of the proposed RSP states the AEP may adjust state transmission charges (attributable to the applicable company, affiliated company or RTO open access transmission tariff [OATT]) to reflect FERC-approved rates and charges during the RSP, whether imposed directly on the companies or through an approved RTO. These include RTO administrative changes imposed, amortization of RTO start-up costs, and/or surcharges for recovery of lost transmission revenues. Such rate changes would be effective 30 days after filing, unless delayed by the Commission (but no longer than a period of 60 days).

AEP characterizes this portion of the RSP as an affirmation of the companies' existing right to make a filing for recovery of FERC-approved costs (AEP Initial Br. 40, 60). AEP believes the proposed expedited review process of such applications is warranted because the Commission should look at new transmission charges and should allow the pass-through of FERC-approved transmission charges (Tr. I, 242-243). Furthermore, AEP believes these costs will be significant, new costs, which are not currently in rates (AEP Ex. 3, at 4; AEP Initial Br. 40). A preliminary estimate of at least some of the anticipated costs in this area is $10.4 million per year for Columbus Southern and $13.1 million per year Ohio Power (AEP Ex. 3, at 4).

Staff expressly supports this provision of the RSP (Staff Ex. 2, at 10). IEU-Ohio recommends that this provision be rejected because transmission costs were taken into consideration when the ETP decision was issued and there are indications that AEP's integration into PJM will create additional transmission revenues. Thus, IEU-Ohio believes that there is no need for this provision (IEU-Ohio Initial Br. 43). Similarly, OEG and OCC argue that this provision will allow AEP to be reimbursed for RTO expenses, but it does not take into account certain savings that will simultaneously be realized, e.g., off-system sales (OEG Reply Br. 19; OCC Reply Br. 13-14). OEG contends that the corresponding savings should be recognized so that the provision is truly a "pass through" (*Id.*). Also, OCC contends that there should be no authorization for additional transmission charges that have not been authorized by FERC or that AEP selects apart from charges in the PJM RTO OATT (OCC Initial Br. 46).

Commission Discussion

We find that this provision of AEP's RSP is reasonable, except as discussed below. In concept, any FERC-approved transmission rates and charges during the RSP should be passed through. We will look at them and ensure that "pass through" is appropriate. Despite IEU-Ohio's, OEG's and OCC's comments, we believe this aspect of Provision Four is appropriate. We do, however, have concerns with the Commission review process set forth in Provision Four. If viewed in isolation, we would not necessarily believe that the 30-day/60-day automatic process was problematic. However, we and our staff will be receiving similar types of applications from more than just AEP. For that reason, we believe that the time period proposed is not as workable as it should be. Therefore, we conclude that the applications to adjust state transmission charges (attributable to the applicable company, affiliate company or RTO OATT) to reflect FERC-approved rates and charges during the RSP (whether imposed directly on the companies or through an approved RTO) shall be automatically approved on the 61st day after filing, unless the Commission rejects, modifies or suspends the filing. We believe this approval process fairly and adequately balances: (1) the desire for a definitive conclusion from the Commission in a prompt manner, (2) the ability of other interested persons to participate, and (3) the concerns for adequate amounts of time to review the anticipated applications in the context of other Commission work.

F. Current Regulatory Asset Recovery (Provision Five of the RSP)

The RSP proposes that AEP continue to recover amortized generation-related transition regulatory assets under the approved ETP. Staff accepts this provision, describing this term as simply continuing practices established in the ETP decision (Staff Ex. 2, at 10). OCC supports this portion of the RSP because it continues one part of the ETP decision. However, OCC does argue that, if the Commission will not require AEP to keep the rest of the ETP bargain, the Commission should revisit this and other aspects of the ETP decision (OCC Ex. 10, at 4; OCC Initial Br. 47). To this argument, AEP contends that an examination of the regulatory assets recovery should not be a consequence of filing the RSP as requested (AEP Reply Br. 42). OCC notes that the bulk of the transition regulatory assets for Ohio Power (associated with mining operations) may no longer represent a liability to Ohio Power (Tr. II, 27, 36). IEU-Ohio is not opposed to this provision, if the Commission accepts its proposed RSP (IEU-Ohio Reply Br. 10, Footnote 11).

Commission Discussion

We also agree with Provision Five and find it appropriate to allow AEP to continue to recover amortized generation-related transition regulatory assets under the approved ETP. We note that no direct opposition to this portion of the RSP was raised by any of the parties.

G. Shopping Incentives and Credits (Provision Seven of the RSP)

AEP proposes in the RSP that Ohio Power will still not charge the regulatory asset charge rider, from January 1, 2006 to December 31, 2007, to the first 20 percent of the Ohio Power residential customer load that switches, as was agreed in the ETP stipulation.[18] Columbus Southern will, through the MDP and 2008, make available to the first 25 percent of the residential class load an incentive of 2.5 mills/kWh that the qualifying customers will receive as a credit. Any unused amount of the incentive money at December 31, 2005, will not be credited to regulatory asset charge recovery. Thus, as proposed under the RSP, Columbus Southern will receive as income any unused shopping incentive balance and not offset the incentive balance against the transition regulatory asset.

---

18 Although both the ETP stipulation and the RSP state that there will be no shopping incentive for Ohio Power customers, the provision to not charge certain shopping Ohio Power customers the regulatory asset charge rider was included in the RSP's Provision Seven under the heading "Shopping Incentives". Nothing in our decision should be construed as converting that term into a shopping incentive or characterizing it otherwise. We have simply chosen to discuss the entirety of Provision Seven at one time.

Columbus Southern's unused shopping incentive through January 2004 was roughly $12.9 million (Tr. II, 108; OCC Ex. 4). The RSP extends the Columbus Southern shopping incentive through 2008. As a trade off, AEP also proposes to alter the manner in which the unused portion of Columbus Southern's shopping incentive is handled (AEP Ex. 2, at 23-24; AEP Ex. 4, at 5; Tr. I, 33). To be clear, AEP's proposal to extend this shopping incentive is tied to the new proposed treatment of its unused balance (AEP Reply Br. 32). AEP argues that the extended shopping incentive, along with increased generation rates, should result in more shopping (AEP Initial Br. 48).

Staff believes that the unused Columbus Southern shopping incentive should be treated as a regulatory liability and flowed back to customers (Staff Ex. 2, at 12). IEU-Ohio concurs (IEU-Ohio Initial Br. 45). AEP believes that this position does not adequately acknowledge that the companies are proposing to extend the shopping incentive (AEP Initial Br. 49).

OCC believes Provision Seven of the plan violates the ETP decision by altering the treatment of the unused Columbus Southern shopping incentive (OCC Ex. 10, at 8; OCC Initial Br. 53). AEP points out that the effect of OCC's position is that no shopping incentive would be available to Columbus Southern residential customers during the RSP (AEP Initial Br. 49).

Green Mountain contends that the RSP's shopping incentive will be inadequate to spur shopping. AEP calculated that the average residential price to compare for the generation component (under the RSP and its shopping incentive terms) will be as follows (GMEC Ex. 5, at fourth set discovery request 1):

Company	2006	2007	2008
Columbus Southern			
With Three Percent Increase	4.26	4.38	4.51
With Termin. of Resid. Discount	4.20	4.27	4.33
Ohio Power			
With Seven Percent Increase	3.73	3.98	3.94
With Termin. of Resid. Discount	3.69	3.89	3.79

In Green Mountain's view, the residential incentive values may be at their highest during the RSP, but they will still not spur shopping (GMEC Initial Br. 10; GMEC Reply Br. 8). In addition to greater shopping incentives, Green Mountain also advocates for shopping credits (avoidable charges) set at market prices (GMEC Initial Br. 11). Green Mountain further advocates that the $10 switching fees be waived, market support generation be provided, a voluntary enrollment process be instituted, new partial payment priority changes be made, and reasonable/nondiscriminatory credit arrangements be created (*Id.* at 10-15, 19-20). AEP states in response to these additional requests that there is no evidence to support them and they should be rejected (AEP Reply Br. 40-14).

Commission Discussion

First, we accept again the term of this provision related to Ohio Power's residential customers who shop in 2006 and 2007. We continue to believe that this term will be beneficial to Ohio Power customers in the near future. No arguments were raised against this part of Provision Seven, except those raised by Green Mountain (in relation to the amount and impact), which we address further below.

The first criticism raised about Provision Seven of the RSP is that AEP proposes to not credit the unused Columbus Southern shopping incentive to regulatory asset charge recovery (and instead extends the incentive through 2008, with any remaining amounts becoming income to Columbus Southern). AEP correctly notes that, if the Commission does not accept this aspect of Provision Seven, there will be no shopping incentive for Columbus Southern's residential customers. Shopping credits and incentives were established to promote customer switching and effective competition. Sections 4928.37 and 4928.40, Revised Code. Accord, *Constellation, supra.* Shopping credits and incentives are not mandated by statute after the MDP. Certainly, however, the idea of having a Columbus Southern shopping incentive during the RSP is attractive, particularly since we are trying to spur further development of the competitive market in AEP's service territories. However, we must weigh that against AEP's clear statements that its proposed extension of the Columbus Southern shopping incentive is contingent upon any remaining amounts at the end of the RSP becoming income to Columbus Southern.

We do not agree that the unused amount of the Columbus Southern shopping incentive at the end of the RSP should become income to that company on the basis that it is a fair trade-off to offering to extend that incentive during the period, as AEP has argued. Under the ETP, Columbus Southern was not going to receive income if that shopping incentive was not completely used during the MDP. Instead, AEP previously agreed to flow those dollars back to customers (by making a reduction to the remaining regulatory asset amounts equivalent to the amount of the unused shopping incentive). Moreover, we do not believe that Columbus Southern should earn income when customers have not shopped sufficiently to utilize the same shopping incentive over an extended period. Furthermore, as explained below, we do not believe that the RSP must include a shopping incentive for Columbus Southern customers either. Therefore, the proposed Columbus Southern shopping incentive portion of Provision Seven of the RSP is rejected.

As previously noted, the ETP decision requires that the unused balance of the Columbus Southern shopping incentive at the end of the MDP be credited back to Columbus Southern customers (via an adjustment to the level of regulatory asset recovery). We agree that customers should benefit in the event that Columbus Southern customers do not shop sufficiently by the end of this year (which is the end of the MDP). We believe that most parties, if not all, would agree that sufficient shopping is very unlikely to occur by the end of the MDP and, thus, an unused dollar amount will exist. However, we conclude a redirected application of the unused shopping incentive monies is more appropriate, while yet still in line with the goal of benefiting customers. LIA and OCC have asked in this proceeding for specific dollars targeted to low-income customer issues because that segment of the customer base may be disproportionately affected by the RSP. As we noted in section VI.B.1 of this decision, we believe that it is appropriate to assist the AEP low-income customers. Therefore, we conclude that $14 million should be should be allotted by AEP for the benefit of the Columbus Southern and Ohio Power low-income customers, as well as for economic development during the RSP period. We will require AEP to work with our Service Monitoring and Enforcement Department staff to develop the details for the use of those sums. Our staff will consult with the Ohio Department of Development in relation to the use of that money in AEP's service territories.

Green Mountain has alleged that the shopping incentives (as identified for Columbus Southern customers above and a zero incentive for Ohio Power customers) will not be sufficient to spur shopping in either company's territory. As we have already noted, shopping incentives are not mandated after the MDP. In any event, the shopping incentives are only one manner of further developing the competitive market and we believe that, in the full context of the proposed RSP, our decision to require monetary assistance for low-income and economic development issues is an appropriate conclusion. With regard to Green Mountain's argument related to partial payment priority, the Commission is not willing to alter its established payment priority scheme just because AEP is seeking to establish a RSP. Green Mountain has also asked for several other specific alterations (establish other credits via avoidable charges, waiver of the $10 switching fees, provision of market support generation and institution of a voluntary enrollment process). We do not believe that these items are needed at this point. Accordingly, we will not adopt them.

H. Other Items (Provisions Eight through Eleven of the RSP)

1. Additional Future Proceedings

AEP recommends (in Provision Eight) that the Commission conduct a proceeding to determine the "manner in which electric generation service should be provided to the companies' customers" after the RSP and report the results to the legislature by December 31, 2005. AEP explains that this provision is intended to avoid facing the same situations at the end of the RSP as we face today (AEP Ex. 2, at 24-25). Staff and IEU-Ohio agree (Staff Ex. 2, at 13; IEU-Ohio Initial Br. 45). OMG and NEMA also appear to agree. Specifically, OMG and NEMA state that, if the Commission approves a RSP for AEP, it should establish a re-opener during 2007 in order to make adjustments to assist market development and to plan for the end of the rate stabilization period (to meet the statutory goals of market-base rates) (OMG/NEMA Initial Br. 12). OCC disagrees that the Commission should complete a report by 2005, arguing that any report completed by that date will not likely provide any valuable information for the post-RSP period (OCC Initial Br. 55-56).

Commission Discussion

This provision of the RSP is acceptable as a recommendation on steps the Commission should consider by the end of the RSP period. The Commission has a mandate to consider all possible options for implementation at the end of the rate stabilization period.

2. Functional Versus Structural Separation

In Provision Nine, the companies would continue functional separation (one corporate entity with separate groups to handle each function). AEP explained that it has not yet received authorization from the Securities and Exchange Commission to structurally separate, although AEP has made that request (AEP Ex. 2, at 25-26). At this point, AEP "does not contemplate structurally separating" the generation assets (*Id.*) because restructuring has slowed down. Staff concurs with this provision, particularly since structural separation could limit or preclude options in the future (Staff Ex. 2, at 13; Tr. IV, 250). IEU-Ohio does not oppose this provision (IEU-Ohio Initial Br. 45).

OCC, OMG, NEMA and Green Mountain state that AEP must structurally separate per Section 4928.17, Revised Code (OCC Initial Br. 56; OMG/NEMA Initial Br. 13-14; GMEC Initial Br. 21). PSEG states that it makes little sense for the Commission to approve the RSP based upon risks/volatility of the competitive market and not protect customers by requiring AEP to implement corporate separation (PSEG Br. 7-8). Green Mountain argues that to continue functional separation seeks something that AEP never lawfully had (because the ETP approved only structural separation) (GMEC Initial Br. 21). Green Mountain states that the Commission should not permit AEP to continue functional separation if the RSP is not implemented (*Id.*).

Commission Discussion

We are willing to accept this term of the RSP for several reasons. First and foremost, AEP has been unable to structurally separate, as it had planned, because it does not have the necessary federal authority to do so. We simply cannot force structural separation when other agencies also must give their approval and that approval has not been forthcoming. Second, we would be remiss if we did not recognize that many expectations surrounding a competitive electric market in Ohio and around the country have changed from 2000, which is when we approved AEP's plan in its ETP proceeding to structurally separate its generation functions from the remainder of its functions. Third, Sections 4928.17(C) and (D), Revised Code, allow the Commission to modify a previously approved corporate separation plan. OCC, OMG and NEMA seem to have overlooked that aspect of the corporate separation statute. More specifically, we conclude that good cause has been shown to allow AEP to operate on a functional separation basis for the RSP period and such functional separation can still provide compliance with the state's policies associated with competitive retail electric service, as enumerated in Section 4928.02, Revised Code.

3. Participation in Other CBPs

Provision 10 of the RSP allows the companies to submit bids in other EDU's CBPs. AEP argues that Section 4928.14(B), Revised Code, compels the Commission to grant this provision of the RSP and the Commission has acknowledged such previously (AEP Initial Br. 52). Staff agrees with this provision and IEU-Ohio believes current law already allows AEP to participate in the CBPs of other EDUs (Staff Ex. 2, 13; IEU-Ohio Initial Br. 46).

Green Mountain contends that AEP should not be permitted to participate in other CBPs until it has structurally separated (GMEC Initial Br. 21-22).

Commission Discussion

AEP correctly notes that we have refused to limit participation in CBPs to non-EDU affiliate participants because of the language in Section 4928.14(B), Revised Code. *In the Matter of the Commission's Promulgation of Rules for the Conduct of a Competitive Bidding Process for Electric Distribution Utilities Pursuant to Section 4928.14, Revised Code*, Case No. 01-2164-EL-ORD, Finding and Order at 9 (December 17, 2003). We find this provision of the RSP to be reasonable. Nothing that Green Mountain has argued on this provision convinces us that this aspect of the RSP should not be approved.

4. Minimum Stay Requirements

Also, the RSP addresses in Provision 11 the topic of minimum stay. It provides that, during the RSP, residential and small commercial customers that return to the standard service must remain through April 15 of the following year, if the customer took generation service from the company between May 16 and September 15. During the RSP, a 12-month minimum stay would be required for large commercial and industrial customers that return under the standard service tariff.

This RSP provision corresponds with AEP's current minimum stay tariff provisions, but those tariff provisions have not been in effect due to a Commission moratorium.[19] AEP believes that minimum stay requirements are needed to avoid seasonal impacts of switching when AEP's prices are essentially annual average rates (AEP Ex. 5, at 5). Staff finds AEP's approach to be reasonable, but also recommends that the alternative mentioned in those tariffs be more fully detailed (Staff Ex. 2, at 14).

OMG and NEMA argue that, before the minimum stay provisions are triggered, the Commission should require that shopping customers be able to return to the standard service offer three times (OMA/NEMA Initial Br. 15). They note that AEP agreed to such a term in its ETP and, since no real shopping has taken place, it makes sense to require this term during the RSP (*Id.*). AEP points out that the Commission did not accept this part of the ETP settlement and nothing was presented in this proceeding to warrant its acceptance now (AEP Reply Br. 39).

IEU-Ohio contends that this topic should be addressed by the Commission on a generic basis, not in this RSP proceeding (IEU-Ohio Initial Br. 46). OCC contends that AEP has not demonstrated a need for the minimum stay or any harm from the moratorium (any alleged harm will only occur if customers actually shop and then return to AEP) and, therefore, the moratorium should remain in place (OCC Initial Br.60).

---

19 The Commission issued a moratorium on any minimum stay requirements for residential and small commercial customers on March 21, 2002, in *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the Electric Utility Industry*, Case No. 00-813-EL-EDI. That moratorium has continued indefinitely. While another proposal is pending before the Commission on the matter, we have not issued a definitive ruling on the matter.

Commission Discussion

We are willing to accept this provision of the RSP. We realize that we still have not addressed the pending minimum stay proposal (which differs from AEP's minimum stay requirements) in the generic proceeding. For the short three-year period of the RSP, we are willing to allow AEP to implement these minimum stay requirements. It will allow us the opportunity to evaluate participation, gaming of enrollments, and the impact of our originally approved minimum stay requirements. We consider this approval to essentially test the debate that has been raised with us for quite a period of time.

VII. Conclusion

Based upon the foregoing, we conclude that the proposed RSP should be adopted (with the exception of the RSP's proposed elimination of the five percent residential discount in Provision Two, the proposed deferral of RTO administrative charges, the proposed deferral of CWIP and in-service plant carrying charges, the proposed review period associated with FERC-approved transmission rate changes, and the proposed treatment of the Columbus Southern shopping incentive) for the reasons set forth herein. We also conclude that OCC's motion to dismiss the application should be denied. Additionally, we conclude that, AEP shall allot $14 million for low-income customers and economic development, and work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars. AEP is, furthermore, allowed to establish a POLR charge.

As we have already mentioned, we believe certain changes are warranted as the MDP ends for AEP. This decision will move AEP to market-based rates for the 2006-2008 period in an appropriate and balanced fashion and conforms with the state's electric policy (Section 4928.02, Revised Code) and this Commission's stated goals. Circumstances are not the same as when we issued our ETP decision and we recognize that fact and have reached conclusions today that we believe are most appropriate for the 2006-2008 period. To the extent any arguments were raised in this proceeding and they are not expressly addressed in this decision, they have been rejected.

As noted earlier in this Order, AEP will be held forth as the POLR to consumers who either fail to choose an alternative supplier or who choose to return to AEP's system after taking service from another energy company. Consistent with Ohio law, the POLR designation places expectations upon EDUs; the companies must have sufficient capacity to meet unanticipated demand. Additionally, the Commission is among many state agencies that have been charged by the Governor to enhance the business climate in Ohio as it competes on a regional, national, and global basis for economic development projects. One of the Commission's roles in this endeavor has been to focus on reliable energy. We believe that, consistent with Section 4928.02, Revised Code, Ohio consumers are entitled to a future secure in the knowledge that electricity will be available at competitive prices. We also feel strongly that electric generators of the future should be both environment-friendly and capable of taking advantage of Ohio's vast fuel resources. With the recognition that new technologies must be forthcoming to replace the utilities' aging generation fleet, we urge AEP to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio. AEP should engage the Ohio Power

Siting Board in pursuit of such a plant. We are encouraged by emerging information that suggests that the IGCC technology will be economically attractive. It is worth noting that the Commission is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan for the period 2006 through 2008.

(2) Twenty-five entities filed motions to intervene in this proceeding. All those requests were granted.

(3) A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004.

(4) A local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004 and rescheduled the local hearing in Columbus, Ohio, for July 1, 2004. At the July 1 and 7, 2004 local hearings, three people provided testimony.

(5) On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. By entry dated June 1, 2004, the examiner deferred a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

(6) The evidentiary hearing began on June 8, 2004, and continued through June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness.

(7) The parties filed post-hearing briefs on July 13 and 30, 2004.

(8) AEP's MDP will end on December 31, 2005.

(9) AEP's proposed elimination of the five percent residential discount in provision two is precluded by the ETP decision.

(10) OCC's motion to dismiss the application should be denied.

(11) We adopt all provisions of the proposed RSP with the exception of the:

(a) RSP's proposed elimination of the five percent residential discount in Provision Two,
(b) Proposed deferral of RTO administrative charges in Provisions One and Six,
(c) Proposed deferral of CWIP and in-service plant carrying charges in Provisions One and Six,
(d) Proposed review period associated with FERC-approved transmission rate changes in Provision Four, and
(e) Proposed treatment of the Columbus Southern shopping incentive in Provision Seven.

(12) Our adopted provisions of the proposed RSP, our decision to require AEP to allot $14 million for low-income customers and economic development, our decisions to require AEP to work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars, and our decision to allow AEP to establish a POLR charge, taken together, appropriately balance three objectives: (a) rate certainty, (b) financial stability for AEP, and (c) the further development of the competitive electric market. Moreover, the combination of the approved components of the RSP, along with the additional conditions of our decision and continuation of the unaffected provisions of the ETP, will prompt the competitive market and continue to provide customers a reasonable means for customer participation in the electric competitive market.

ORDER

It is, therefore,

ORDERED, That OCC's motion to dismiss this application is denied. It is, further,

ORDERED, That AEP's application is approved, subject to the modifications set forth in this decision. It is, further,

ORDERED, That AEP work with our Service Monitoring and Enforcement staff to work out the details for the allotted low-income and economic development dollars. It is, further, ORDERED, That a copy of this opinion and order be served upon all 28 parties to this proceeding and any interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GLP;geb

Entered in the Journal

JAN 26 2005

Reneé J. Jenkins
Secretary

051278comcf072606.wpd

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the Public Service Commission of West Virginia, in the City of Charleston, on the 26th day of July, 2006.

CASE NO. 05-1278-E-PC-PW-42T

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, both dba
AMERICAN ELECTRIC POWER

Rule 42T application to increase electric rates and charges; request for reactivation and modification of the Expanded Net Energy Cost mechanism; proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance; request for implementation of a System Reliability Tracker mechanism; and request for waiver of certain provisions of the Commission's Rules.

COMMISSION ORDER

The Commission approves the Stipulation.

BACKGROUND

On August 26, 2005, Appalachian Power Company and Wheeling Power Company, both doing business as American Electric Power (AEP), filed a tariff containing increased rates and charges for furnishing electric service to approximately 474,965 customers. The initial proposed increased rates and charges were to become effective September 25, 2005.

In addition to the rate application, the joint application included (1) a request for approval to reactivate and modify the Expanded Net Energy Cost mechanism (ENEC); (2) approval of a proposal for the disposition of Appalachian Power Company's ENEC over-recovery balance; (3) approval to implement a System Reliability Tracker mechanism; and (4) a waiver of certain provisions of the Commission's rules: Rule 4.2.1.a. - waiver of refund requirement with respect to all non-residential customers; 4.8.1.a.F. - waiver of the 8-hour reconnect requirement; and 4.8.1.a.H. - wavier to avoid dangers associated with reconnect personnel acceptance and transportation of money.

On September 13, 2005, the Commission issued an order suspending the use of the rates and charges stated in the revised tariff sheets until 12:01 a.m., June 23, 2006, unless otherwise ordered by the Commission.

On November 10, 2005, the Commission issued an order that, among other things, set this matter for hearing to begin on February 28, 2006, and established a procedural schedule.

The following parties were granted intervenor status: the Commission's Consumer Advocate Division (CAD), the West Virginia Energy Users Group (WVEUG), Century Aluminum (Century), South Bluefield Neighborhood Association (SBNA), West Virginia Building and Construction Trades Council (Trades Council), Concept Mining, Inc. (Concept), The Kroger Co. (Kroger), Huntington Sanitary Board (Huntington), South Putnam Public Service District (South Putnam), and West Virginia Community Action Partnership (WVCAP). (See Orders dated November 10, 2005, and December 7, 2005).[1]

At AEP's request, the Commission issued an order on January 27, 2006, that tolled the statutory suspension period for five (5) weeks, from June 23, 2006, until July 28, 2006. The order rescheduled the hearing, including public comments, to begin on April 18, 2006, and established a new procedural schedule.

Public comment hearings were scheduled and conducted in Beckley, Logan, Huntington, and Bluefield between February 6, 2006, and February 15, 2006.

In accordance with the schedule established by the Commission, AEP, Commission Staff (Staff), CAD, Century, WVEUG, Kroger, South Putnam, Huntington, and WVCAP submitted pre-filed testimony in advance of the hearing.

On April 18, 2006, the Commission convened the hearing as scheduled. AEP, Staff, CAD, Century, WVEUG, Kroger, South Putnam, Huntington, and WVCAP appeared and were represented by counsel. There were no members of the public present to provide comments.

After a short recess in the proceedings, the parties advised the Commission that they had reached a settlement, in principle, on a majority of the issues in the case. The parties indicated that a rate issue involving Century was still open for further discussion and

[1]Although Concept and the Trades Council had been granted intervenor status, both subsequently withdrew as parties to the case. Other than an appearance at the February 15, 2006 public comment hearing, SBNA did not participate in any other aspect of this case.

negotiation. The Commission directed the parties to reduce the settlement to writing. The parties were to reappear and submit the written settlement agreement to the Commission on April 21, 2006.

Prior to adjourning the hearing, the parties submitted into evidence the pre-filed testimony of various witnesses. (*See*, Exhibits contained in hearing transcript of April 18, 2006).

The hearing reconvened on April 21, 2006. At that time, the parties were not prepared to present a written settlement. The parties were directed to return on April 24, 2006, to either submit a written settlement or to proceed with the evidentiary hearing.

On April 24, 2006, the parties appeared before the Commission and announced that a Joint Stipulation and Agreement for Settlement (Stipulation) had been signed by the parties. The Stipulation was entered into evidence. (*See*, Joint Exhibit 1). The parties explained the Stipulation on the record and indicated that it resolved all issues except for the Special Rate Mechanism for Century Aluminum (Century Rate). The Century Rate proposal is set out in paragraph 37, pp. 14-16 of the Stipulation. Staff was the only party not in agreement with that aspect of the Stipulation.

The parties were instructed to file briefs supporting their respective positions on the Century Rate.

On April 24, 2006, AEP filed affidavits indicating that the required notices were published, posted and mailed in accordance with the Commission's orders and *Tariff Rules*.

Initial Briefs

<u>Staff</u>

Staff filed its Initial Brief on May 4, 2006. Staff reiterated that it was in agreement with all terms and conditions of the Stipulation with the exception of the Century Rate aspect. Additionally, Staff agreed that Century is a valuable industrial asset to the citizens of West Virginia and that Century provides much-needed jobs.

Nonetheless, Staff argued that the Commission is not statutorily authorized to authorize a special utility rate for certain energy-intensive industries. Staff cited *W. Va. Code* §§ 24-1-1(a)(4); 24-1-1(c); 24-2-2(a); 24-2-3; 24-2-7(a); 24-3-1; and 24-3-2 in support of its position.

Staff stated that the Commission had previously rejected a request that a special sewer rate be created for housing projects for the low income and/or the elderly. (*Jefferson County Public Service District*, Case No. 00-1329-PSD-19A, Recommended Decision entered March 9, 2001, final March 29, 2001, citing *Hope Gas Co.*, Case No. 82-158-G-42T (Hearing Examiner's Decision entered 1/11/83), Supplement to Vol. 70 ARPSCWV 1982-1983.)

Conversely, Staff acknowledged that in a separate case, the Commission had previously approved a settlement that did "not preclude AEP-APCo or AEP-WPCo from entering into special contracts for specific customers that provide for rates different from those contained in the companies' tariffs, or from seeking Commission approval of new or experimental rates of limited application. (*Appalachian Power Co.*, Case No. 99-0409-E-GI, June 2, 2000, at p. 8).

Staff made two observations with regard to its experience with special contracts and experimental rates. First, Staff stated that when a utility and a customer enter into a special contract under which the customer will be paying a rate that is less than the rate of the customer's class rate, the special rate is generally cost-based and beneficial to the utility and its other customers. (See, *Wheeling Power Company*, Case No. 90-243-E-42T, Commission order February 15, 1991, citing *Wheeling Electric Company*, Case No. 86-587-E-42, Commission order, August 5, 1988, discussing the benefits of having a special interruptible rate for electric service).

Staff's second observation regarding the use of special contracts filed pursuant to Rule 39 of the Commission's *Tariff Rules* is that special contracts are not approved in the manner requested in the Stipulation. Staff stated that the Commission has in the past declined to approve the specific terms and conditions of special contracts. However, the Commission has stated that it would review disputes over allegations of imprudence which may be made. (See, *Mountaineer Gas Co.*, Case No. 94-0895-GT-PC, Commission order June 1, 1995, *petition to reconsider denied*, Commission order July 28, 1995).

Staff indicated that there was "one glaring exception" to the Commission's policy of declining to approve the specific terms and conditions of a special contract. That exception is found in *Appalachian Power Company and American Alloys, Inc.*, Case No. 87-883-E-PC, Commission order December 24, 1987). In that case Staff stated that the Commission approved the special contract which provided for APCo charging American Alloys a lower deposit rate than that required by the Commission's *Electric Rules*. The Commission concluded that APCo would be permitted in future rate cases to recover any loss which it may experience by accepting less than the maximum allowed security deposit. Staff asserted that it was unaware of any statutory provision that would authorize the Commission to guarantee a preferential rate treatment by permitting APCo to recover from its other ratepayers any loss it incurred as the result of American Alloys being given permission to pay a deposit less than required by the *Electric Rules*.

CAD

On May 4, 2006, CAD filed its Initial Brief. CAD advocated for the approval of the Stipulation, including the Century Rate provisions.

CAD stated that Century would bear a substantial amount of the costs related to the overall revenue increase agreed to in the Stipulation. (Stipulation, Ex. E). CAD explained that under the three-year Century Rate proposal, Century will pay a base rate each month to AEP equal to the currently effective rate, plus a surcharge based on the market price of aluminum. In months when the base rate plus the surcharge is higher than the rate that would otherwise be applicable to Century, a credit equal to the excess will be entered into the "Century bank." Conversely, in months when the base rate plus the surcharge is less than the otherwise applicable rate, a debit will be recorded. A cumulative running balance of the Century bank will be kept.

CAD stated that at the end of the three-year experimental rate period, in 2009, the operation of the Century Rate will be examined and parties will be free to make whatever recommendations related to continuation, elimination or modification of the rate that they believe are appropriate at that time. If the Century Rate is continued, then whatever balance is in the Century bank will simply be rolled forward and the monthly accounting will continue. However, if the experimental rate is ended in 2009, then the Stipulation provides that Century will keep any surplus in the Century bank while any deficit will be spread to all other AEP customers.

As a hedge against a possible deficit in the Century bank, CAD noted that Century agreed to two major changes in its experimental rate. First, Century agreed to deposit $1 million with AEP for the protection of other ratepayers. If there is a surplus at the end of the experimental rate, the $1 million deposit will be spread as a credit to all other ratepayers. If there is a deficit, the $1 million deposit will serve to reduce the deficit. Second, Century agreed to raise the ceiling on the surcharge so that greater surplus amounts would be built up during times of high aluminum prices. CAD asserted that raising the ceiling makes it more likely that any deficit in the latter part of the three-year rate period will be offset by surpluses developed during the early part of the three-year period.

CAD stated that it supports the experimental Century Rate within the context of the entire settlement. While there may be parts of the Century Rate proposal that CAD likes or dislikes in isolation, CAD believes that the overall Century Rate is reasonable, and there are sufficient safeguards provided to protect the interests of the other ratepayers. Most importantly, CAD noted that the proposed Century Rate was of limited duration and would be thoroughly reviewed at the end of three years. At that time, CAD stated that if the Century Rate has not been beneficial to both Century and other ratepayers, it is doubtful that it would be renewed in its present form.

CAD reminded the Commission that the Century Rate was part of the resolution of controversies concerning proper allocation of the ENEC bank which was built up from 1996 through 1999. In return for getting agreement on the experimental rate design, Century gave up any claim to a portion of the ENEC bank. If the Commission declines to approve the experimental rate design for Century, then the parties have made clear that they reassert their original positions on the proper allocation of the ENEC bank. CAD indicated that these further controversies can be avoided by approving the Century Rate design as set forth in the Stipulation.

<u>AEP</u>

On May 4, 2006, AEP filed its Initial Brief. AEP asserted that the Century Rate contained in the Stipulation was reasonable and appropriate and an essential element of the Stipulation.

AEP noted that the Commission has a statutory obligation to balance the interests of customers, utilities and the state's economy. (*W.Va. Code* § 24-1-1(b)). AEP asserted that the Century Rate is an instance of such permissible balancing. It recognized the importance of Century to the West Virginia economy and the millions of dollars of AEP's fixed costs Century will bear. AEP argued that the fairness and reasonableness of Century's Rate was demonstrated by the support it has from the diverse interests supporting it.

AEP asserted that the *Code* does not contain a blanket prohibition of all preference and discrimination in rates. Instead, the *Code* prohibits discrimination that is unjust, undue, or unreasonable. (<u>See</u>, *W.Va. Code* §§ 24-1-1(a)(4); 24-2-2; 24-2-3; 24-3-1; and 24-3-2). AEP stated that to the extent the Century Rate constitutes a rate treatment that is at variance with what is available to other customers, the variance is just and reasonable because it serves the interests of all affected parties and fairly balances the interests of the utility, all classes of customers and the State's economy.

AEP argued that the *Code* does not require rates to be exclusively based on costs to be reasonable. *W.Va. Code* § 24-1-1(a)(4) simply mandates that rates be "based primarily on the costs of providing these services." In the case of the Century Rate, AEP stated that the greatest part of the rate for service will be paid regularly, without discount adjustment or leeway in the timing of the payment. Depending on the prevailing commodity price of aluminum, Century may be required to pay a 100% cost-based rate and could be required to accrue amounts in excess of 100% which would be used to pay full rates at times when aluminum prices may be lower. AEP asserted that even if Century is paying the minimum amount required under the Century Rate proposal, that minimum rate satisfies the requirements of *W.Va. Code* § 24-1-1(a)(4), in that it is primarily cost-based.

Century

Century filed its Initial Brief on May 4, 2006. Century noted that the proposed Century Rate will provide it with some protection against a decline in the price of aluminum. Century stated that this would protect nearly 700 Century union jobs, potentially 1100 Alcan jobs and the economic benefits that Century brings to West Virginia.

Century stated that energy costs account for one-third of its production costs. Its energy expenditures exceed $75.6 million per year at AEP's current rates. Century is 11% of AEP's load and is AEP's largest single customer. Century stated that without it, AEP would have to pass on an additional $5 to $7 million dollars per year of AEP's fixed costs to the remaining rate payers. The proposed Century Rate is a means of controlling its energy costs. When aluminum prices are high, Century can afford to pay more for power. But, Century stated when the prices are low, it cannot afford the higher tariff rate and remain economically viable.

Century argued that economic development and job retention are matters which the Commission may address under its statutory authority. The key issue is whether a rate is unjustly discriminatory. Century stated that the fact that various classes of customers are charged different rates does not in and of itself make a rate discriminatory. It must be unreasonably discriminatory in light of the factors that the Commission can consider, such as the cost of service, purpose of service, quantity of service, or any other matter which presents a substantial difference.

WVEUG

The WVEUG filed its Initial Brief on May 4, 2006. WVEUG stated that the Stipulation is fair to all customer classes, including the members of the WVEUG. It noted that the Stipulation nearly cuts in half the rate increase as originally proposed. In reducing specific rate impacts, WVEUG believes that the Stipulation implicitly recognizes the inherent value of industrial customers, the jobs they provide, and the additional benefits that are created as a result of their investment in West Virginia. WVEUG requested that the

Commission be mindful of West Virginia business and industry when considering whether the Stipulation, is, without modification, in the public interest. WVEUG believes that the Stipulation is, as a whole, in the public interest.

WVEUG noted that Rule 39 of the Commission's *Tariff Rules* recognizes that large industrial customers are often better served through special service agreements. Such agreements balance the uniqueness of larger customers and the benefits they provide to the entire system in terms of their fixed contributions to the rate base. WVEUG asserted that Century is worthy of the service flexibility requested in the Stipulation.

Reply Briefs

Staff

Staff filed its Reply Brief on May 15, 2006. Staff repeated that Century is a valuable industrial asset to the state's economy and that it is engaged in an energy-intensive industry that has been on the decline in the United States. However, Staff opined that until the Legislature in West Virginia enacted a statute providing the Commission with the authority to allow for special utility rates for depressed energy-intensive industries, the Commission is not statutorily authorized to do so.

CAD

CAD filed its Reply Brief on May 15, 2006. CAD disagrees with Staff's assertion that the Commission is not authorized, by statute, to adopt the Century Rate. CAD asserts that *W. Va. Code* §§ 24-2-2 and 3 give the Commission plenary authority over the rates of utilities within its jurisdiction. Those statutes set out guidelines for the Commission in establishing rates. But, CAD argued that the guidelines are not absolute and recognize the quasi-legislative nature of the ratemaking process, whereby the Commission is able to fully inform itself about the impacts of various proposals and adapt to changing conditions. See, *Central West Virginia Refuse, Inc. v. PSC*, 438 S.E.2d 596 (W.Va.1993).

CAD stated that the entire ENEC concept adopted for AEP in 1984 is an experimental rate whereby shortfalls in particular cost or revenue items are not borne by the Company, but instead are recorded as a regulatory asset and ultimately recovered from ratepayers. (*Appalachian Power Company*, Case No. 83-697-E-42T, 72 ARPSCWV 834, 841-842 (Sept. 28, 1984)).

CAD also pointed to another experimental rate structure aimed at economic development for qualifying industrial customers. Under the economic development rider, new industrial customers or existing customers that increased their billing demand would be billed at 70%, 80% and 90% of the full billing demand in succeeding years over a three-year period. *See*, Case Nos. 87-154-E-P, "Final Order" (April 7, 1987); Case No. 88-696-E-PC, "Final Order" (Dec. 2, 1988); Case No. 89-796-E-PC, "Final Order" (Dec. 7, 1989); Case No. 91-009-E-PC, "Final Order" (Jan. 18, 1991).

CAD asserted that the experimental rate proposed in this case is a variation on the themes set out in the previous experimental rates. At the end of the three-year period, the rate design will be reviewed and the Commission will ultimately have to determine whether the Rate provided sufficient flexibility to Century while at the same time adequately protected the interests of AEP and other ratepayers. CAD stated that modifications may need to be made. However, CAD urged that such changes should be based on actual experience.

CAD agreed with Staff that the Commission should be very cautious in allowing experimental rates. CAD believes that experimental rates should be carefully defined as the Century Rate in the Stipulation has been. CAD asserted that the Commission has the statutory authority to adopt the Century Rate and should do so.

<u>Century</u>

Century filed its Reply Brief on May 15, 2006. Century asserted that the Commission has the authority to approve the Century Rate, that the Rate is fair, just and non-discriminatory and primarily cost-based.

Century asserted that the Commission's only limitation on the power to approve experimental rates is that they must be reasonable. Approval of special rates to retain industry is included in the Commission's authority, Century argued.

Century noted that the Commission's failure to approve the Century Rate will result in a rejection of the Stipulation and a reversion to the parties' original position with regard to the ENEC bank balance. The Stipulation resolves numerous contentious issues that will have to be litigated if the Century Rate is not approved.

<u>WVEUG</u>

WVEUG filed its Reply Brief on May 15, 2006. WVEUG stated that the central issue is whether the Century Rate is generally cost-based and beneficial to the utility and its customers. WVEUG asserted that the Century Rate is primarily cost-based because the minimum rate that Century will pay is approximately 90% of the total rate that Century would otherwise pay. WVEUG also asserted that the Century Rate is beneficial to AEP's other customers as Century will be paying a substantial portion of the costs related to the overall revenue increase in this case. Additionally, in exchange for the special rate, Century is agreeing to forgo any claim it may have to the ENEC bank balance which is arguably a benefit to other customers.

AEP

AEP's Reply Brief was filed on May 15, 2006. AEP stated the issue was whether the provisions of Chapter 24 of the *Code* grant the Commission sufficient flexibility to approve the Century Rate. AEP stated that it and all the other parties except Staff believe the Commission has the required flexibility to approve the Century Rate.

AEP asserted that Staff's proposal to defer a ruling on the treatment of a possible deficit is neither fair nor equitable. AEP stated that it is practically impossible the Century Rate will produce an exact zero balance at the end of the period, so there would be some surplus or some deficit. AEP stated that the question is whether the mechanism which could produce such a surplus or deficit is unduly, unjustly or unreasonably preferential or discriminatory.

AEP argued that the Century Rate assures the ratepayers a substantial benefit - that Century will be allocated the responsibility for many millions of dollars of fixed costs which were the responsibility of those customers until the recent appearance of Century as a customer and, which could become the responsibility of those customers again if Century ceases operation. AEP stated that the Century Rate offers ratepayers a balanced calculated risk. But, it does not provide Century a guaranteed subsidy. Overall, AEP asserted that the arrangement provides a risk/benefit prospect that commands the support of all ratepayer constituencies.

AEP disputed that the Century Rate constituted unjust or unreasonable discrimination. AEP stated that preference or discrimination involve treating similarly situated entities differently. Century is unique and no other entity is similarly situated. Even if the proposal does constitute some measure of preference or discrimination, AEP stated that it was completely just and reasonable. AEP referenced the Commission's decision in *Appalachian Power Company and American Alloys. Inc.* Case No 87-883-E-C. AEP asserted that the same compelling reasons for the special treatment given American Alloys is the same economic considerations that are pertinent to Century.

AEP asked that the Commission approve the Century Rate and approve the Stipulation.

DISCUSSION

The Commission has had the opportunity to review the pre-filed testimony representing the respective parties' initial positions in this case. Additionally, the Commission has reviewed the Stipulation (attached hereto).

The only matter that remains for the Commission to resolve is the Century Rate. The Commission has carefully reviewed and considered the briefs and positions of the parties on that issue.

Staff's position as to the Commission's authority to approve the Stipulation inclusive of the Century Rate rests upon a narrow interpretation of the applicable statutes as well as past practices and policies of the Commission. The Commission is not persuaded that such an approach is appropriate and concludes that, in this case, the Commission is vested with the inherent jurisdiction, power and authority necessary to flexibly carry out its regulatory responsibilities while protecting the public interest and maintaining or enhancing West Virginia's economic viability.

It is no secret that in the past two decades the electric industry in the United States has undergone, and will continue to experience, tremendous change. Competitive forces in the market and demand for low-priced electricity are driving this change.

West Virginia, as a regulated state, cannot function obliviously to the changes occurring outside its boundaries. Instead, this Commission, if it is to protect the public interest and enhance the state's economic viability, must meet these challenges with unique and innovative approaches within the framework of traditional ratemaking and rate-based, rate-of-return regulation.

Introduction, development, testing and implementation of such unique and innovative approaches are within the scope of this Commission's statutory authority. The Commission encourages all parties to develop and propose unique and innovative approaches that will encourage investment in and expansion of capacity accompanied by an adequate rate of return, while at the same time maintaining and enhancing the state's position and that of its citizens.

For these reasons, the Commission concludes that the rates, charges, and terms and conditions of service contained in the Stipulation are reasonable and should be approved. The Stipulation will be approved as submitted.

FINDINGS OF FACT

1. All parties to this case jointly presented a Stipulation in resolution of all issues.

2. The Stipulation left open the issue of whether to adopt the proposed Century Rate. Staff was the only party objecting to that aspect of the Stipulation.

CONCLUSIONS OF LAW

1. The Commission is vested with the inherent jurisdiction, power and authority necessary to flexibly carry out its regulatory responsibilities while protecting the public interest and maintaining or enhancing West Virginia's economic viability.

2. The Commission concludes that it has the authority to approve the Century Rate.

3. The Commission concludes that the rates, charges, and terms and conditions of service contained in the Stipulation are reasonable and should be adopted. The Stipulation will be approved as submitted.

ORDER

IT IS, THEREFORE, ORDERED that the Joint Stipulation and Agreement for Settlement filed on April 24, 2006, and attached hereto as Appendix A, is hereby adopted by the Commission as the final resolution of the issues in this proceeding.

IT IS FURTHER ORDERED that the parties shall abide by the terms and conditions of the Stipulation.

IT IS FURTHER ORDERED that within 10 days of the date of this order Appalachian Power Company and Wheeling Power Company, both doing business as American Electric Power, shall file with the Commission's Tariff Office the revised tariff sheets setting forth the rates and charges approved by this Order.

IT IS FURTHER ORDERED that the rates and charges approved by this order are hereby effective for all service rendered on and after July 28, 2006.

IT IS FURTHER ORDERED that upon entry of this order this case shall be removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that the Commission's Executive Secretary serve a copy of this order upon all parties of record by United States First Class Mail and upon Commission Staff by hand delivery.

A True Copy, Teste:

Sandra Squire

Sandra Squire
Executive Secretary

JMH/klm
051278cf.wpd

PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CHARLESTON

RECEIVED
06 APR 24 PM 2:03
W. VA PUBLIC SERVICE COMMISSION
SECRETARY'S OFFICE

CASE NO. 05-1278-E-PC-PW-42T

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY

Joint Application for Rate Increases on Notice with Proposed Effective Dates and Changes in Tariff Provisions, Pursuant to W.Va. Code, §24-2-4a, *inter alia*, for Reactivation and Modification of Expanded Net Energy Cost Mechanism, for Disposition of ENEC Over-recovery Balance, for Implementation of System Reliability Tracker Mechanism, and for Waiver of Provisions of the Commission's Rules.

JOINT STIPULATION AND AGREEMENT FOR SETTLEMENT

Pursuant to *W. Va. Code* 24-1-9(f) and Rule 13.4 of Title 150, Series 1, *Rules of Practice and Procedure*, the following parties to this proceeding (hereinafter "the Stipulating Parties"), Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (collectively "the Companies"), the Staff of the Public Service Commission of West Virginia ("the Staff"), the Consumer Advocate Division of the Public Service Commission of West Virginia ("the CAD"), E.I. du Pont de Nemours and Company, Huntington Alloys Corporation, Bayer Crop Science/Bayer Material Science, PPG Industries, Inc., Union Carbide Corporation, and Steel of West Virginia, Inc. ("SWVA, Inc.") referred to collectively as West Virginia Energy Users Group ("WVEUG"), Century Aluminum of West Virginia, Inc. ("Century"), The Kroger Co. ("Kroger"), the Huntington Sanitary Board and South Putnam Public Service District (collectively "Huntington/South Putnam"), and the West Virginia Community Action

Partnership ("WVCAP"), join in this Joint Stipulation and Agreement for Settlement ("this Agreement"), and request that the Public Service Commission of West Virginia ("the Commission") approve and adopt it, in its entirety and without modification, as the full and final resolution of the instant proceeding. In support of this Agreement, the Stipulating Parties make the following representations:

Procedural History

1. On August 26, 2005 the Companies filed their Joint Application to reinstate the Expanded Net Energy Cost ("ENEC") proceedings, increase base rates and make changes in classifications, charges, rules and regulations, and other tariff provisions. The Joint Application was supported by seven volumes, including Rule 42 data, workpapers, ENEC data, proposed tariffs, a class cost of service study, and a report on emerging and state-of-the-art concepts.

2. On September 13, 2005 the Commission issued an Order which, among other things, suspended the use of the rates and charges stated in the Companies' revised tariff sheets until June 23, 2006. By order of January 27, 2006 the Commission, in response to a motion filed by the Companies, extended the suspension period until July 28, 2006, but authorized deferred accounting for ENEC to commence July 1, 2006.

3. At various dates various entities filed petitions to intervene, which were granted by the Commission. Intervenors Concept Mining, Inc. and the West Virginia State Building and Construction Trades Council, AFL-CIO later withdrew from this proceeding. The South Bluefield Neighborhood Association intervened but did not offer testimony, participate in any of the settlement meetings, or appear at the April 18, 2006 hearing in this matter.

4. On September 26, 2005 the Companies filed the direct testimony and exhibits of Dana E. Waldo, Terry R. Eads, Paul R. Moul, John M. McManus, Stephen D. Baker, Jeffrey B. Bartsch, Alan D. Bragg, Jeffrey L. Brubaker, Steven H. Ferguson, Chris Potter, Oliver J. Sever, O. Patrick Taylor, and Philip A. Wright.

5. The Companies provided public notice in substantial compliance with the Commission's directions.

6. In the course of the discovery phase of this proceeding, numerous requests for information were filed by various parties and responded to by the parties to whom they were addressed.

7. On January 18, 2006 the Companies filed the supplemental direct testimony and exhibits of Terry R. Eads, Steven H. Ferguson, and Chris Potter, and a revised Volume IV containing revised ENEC data.

8. On March 8, 2006 the Staff filed the direct testimony and exhibits of James W. Ellars, Michael L. Fletcher, Steven M. Kaz, Robert R. McDonald, Edwin L. Oxley, David L. Pauley, and Thomas D. Sprinkle, as well as Staff Rule 42 Reports for APCo and WPCo; the CAD filed the direct testimony and exhibits of Byron L. Harris, Emily Medine, Randall Short, and Ralph Smith; WVEUG filed the direct testimony and exhibits of Stephen J. Baron, Richard A. Baudino, Timothy R. Duke and Richard Piotrowski; Century Aluminum filed the direct testimony and exhibits of Gerald J. Kitchen and Ronald Thompson; WVCAP filed the direct testimony and exhibits of Dwight Coburn; The Kroger Co. filed the direct testimony and exhibits of Kevin C. Higgins; West Virginia Building and Construction Trades Council, AFL-CIO filed the direct testimony and exhibits of George L. Donkin; and the Huntington Sanitary Board

and South Putnam Public Service District filed the direct testimony of Jack D. Gaines, J. Bruce Fox, and Michael McNulty.

9. On April 7, 2006 the Companies filed the rebuttal testimony and exhibits of Dana E. Waldo, Terry R. Eads, Paul R. Moul, Stephen D. Baker, Steven H. Ferguson, Jeffrey L. Brubaker, Jeffrey B. Bartsch, James I. Warren, Philip J. Nelson, O. Patrick Taylor, Alan D. Bragg, and Chris Potter.

10. On April 7, 2006 the Staff filed the amended direct testimony and exhibits and rebuttal testimony of Robert R. McDonald and the amended direct testimony and exhibits of Thomas D. Sprinkle; the CAD filed the rebuttal testimony and exhibits of Byron L. Harris and Ralph C. Smith; WVEUG filed the rebuttal testimony and exhibits of Stephen J. Baron; Century Aluminum filed the rebuttal testimony and exhibits of Gerald J. Kitchen; the Huntington Sanitary Board and South Putnam Public Service District filed the rebuttal testimony and exhibits of Jack D. Gaines.

11. On April 14, 2006 the Companies filed the additional rebuttal testimony of Chris Potter.

12. For some weeks prior to hearing, the Stipulating Parties engaged in settlement discussions concerning all aspects of the instant proceeding, and have now reached agreement on a comprehensive series of proposals to recommend to the Commission as a fair and just settlement of the issues in this proceeding.

13. At a hearing held on April 18, 2006 the Stipulating Parties represented to the Commission that a settlement in principle had been reached among those parties. The Commission directed the Stipulating Parties to provide it with a written and executed

settlement agreement memorializing the settlement by 9:30 a.m. April 21, 2006. The Commission admitted into the record all of the testimony and exhibits specified above.

14. Except as set forth in paragraph 15 below, the Stipulating Parties agree that the substantive elements of the proposed settlement, which are hereby submitted for the Commission's approval, resolve all of the issues in this proceeding, and are set forth in particular below and in the exhibits attached hereto.

15. Although the Stipulating Parties have reached agreement on most of the substantive elements presented in the case, there remain two related issues in contention among the parties which will have to be resolved by the Commission. This first issue involves one aspect of the Special Rate Mechanism for Century Aluminum set forth in paragraph 37 below. As explained in paragraph 37d, there is the possibility that at the end of experimental rate program for Century in 2009, there may be a deficit (an under-recovery) which will be spread to other customers in future rate proceedings. The second issue is the treatment of the ENEC Bank discussed in paragraphs 19 to 24 below. As part of the consideration for the Special Rate Mechanism, Century has given up any claim for a portion of the ENEC Bank. If the Special Rate Mechanism, including the recovery of any deficit, is not approved, Century will reassert its claim for a portion of the ENEC Bank. Set forth below are the positions of the respective parties on these issues.

a. Staff. Staff has agreed to all terms and conditions of the Joint Stipulation and Agreement for Settlement except for the condition in the Special Rate Mechanism for Century Aluminum whereby any deficit that remains at the end of the experimental rate mechanism time period will be recorded by APCo as a regulatory asset and flowed back to all other ratepayers. Staff is willing to defer any argument concerning the deficit until the end of the experimental rate period, and if a deficit in fact exists at that time, advance its arguments to the Commission regarding the proper treatment of such deficit.

b. The Companies. APCo and WPCo support approval of the Special Rate Mechanism for Century Aluminum, but do not support the special rate mechanism without the provision objected to by the Staff, which is an integral element of the negotiated special rate mechanism. The Companies ask the Commission to resolve here and now any issues about the experimental rate program and to approve it or disapprove it without deferring any critical issues for resolution at a later date.

c. Century Aluminum. If the Commission does not approve this experimental rate program in all its particulars, including providing APCo recovery of any deficit, and thereby APCo does not enter into a special contract with Century Aluminum, then Century withdraws its support for the remainder of this settlement and reasserts its claim to the ENEC Bank.

d. WVEUG. WVEUG supports approval of the Special Rate Mechanism for Century Aluminum. However, if the Special Rate Mechanism is disapproved and Century reasserts its claim for a portion of the ENEC Bank, WVEUG asserts that the allocation of the ENEC Bank set forth in Exhibit C continues to be reasonable and should be approved as part of this settlement.

e. The Kroger Co. The Kroger Co. takes the same position as WVEUG.

f. CAD. Within the context of the overall settlement, the CAD supports approval of the Special Rate Mechanism for Century Aluminum. However, if the Special Rate Mechanism is disapproved and Century reasserts its claim for a portion of the ENEC Bank, CAD asserts that Century has no legitimate claim on the ENEC Bank.

Accordingly, the ENEC Bank should continue to be allocated as set forth in Exhibit C hereto.

g. Huntington Sanitary Board and South Putnam Public Service District. These parties take the same position as the CAD.

h. Accordingly, the Stipulating Parties ask that the Commission render a specific decision on the issues outlined above. The Stipulating Parties stand ready to offer oral argument, witnesses and/or written briefs on these issues at the direction of the Commission.

16. **Expanded Net Energy Cost** The Stipulating Parties agree that the Expanded Net Energy Cost ("ENEC") mechanism should be reinstituted for the Companies, with new ENEC rates established in this proceeding, and annual ENEC proceedings to resume in 2007.

17. The Stipulating Parties agree to the following ENEC rates:

a. Consistent with the Commission's January 27, 2006 Order in this proceeding, the Stipulating Parties acknowledge that the Companies will commence deferred accounting for revenues and costs included in the ENEC on July 1, 2006 and agree that the ENEC rates to be used for such deferred accounting for each tariff class on July 1, 2006, shall be those set forth in Company Exhibit No. 1, Revised Volume IV, Revised Section 2, Attachment 1, which is attached hereto as Exhibit A and incorporated herein.

b. The Stipulating Parties agree that, beginning July 28, 2006, the ENEC rates for each tariff class shall be those set forth in Company Exhibit No. 1, Revised Volume IV, Revised Section 1, Attachment 1, which is attached hereto as

Exhibit B and incorporated herein. Those ENEC rates will stay in effect until July 1, 2007, or further order of the Commission, and are projected to produce additional annual revenues of $56.01 million.

18. The Stipulating Parties agree to the following elements and procedures to govern further ENEC proceedings.

a. The Companies will make their next ENEC filing by March 1, 2007, and then will make new ENEC filings by March 1st of each year thereafter.

b. In the ENEC filing of March 1, 2007:

i. the actual cost review period shall be July 1, 2006, through December 31, 2006; and

ii. the forecast period shall be July 1, 2007, through June 30, 2008.

c. In subsequent annual ENEC proceedings the actual cost review period shall be the immediately preceding calendar year, and the forecast period shall be the twelve months from July 1st of the year in which the proceeding is initiated through June 30th of the following year.

ENEC Over-Recovery Balance

19. The Stipulating Parties agree that the accumulated ENEC over-recovery balance ("the Bank") being held by APCo, and to be fed back to customers pursuant to this Agreement, is $51,207,683, plus simple interest on the principal balance as per the Commission's November 10, 2005 Order. That simple interest has been accrued since November, 2005 and will continue to be accrued on the declining principal balance until the entire balance has been fed back to customers.

20. The allocation of the Bank among customer classes and customers shall be in accordance with the proposal of WVEUG, which is attached hereto as Exhibit C and incorporated herein by reference.

21. Beginning July 28, 2006, the Companies shall implement negative surcharges by customer class, for all classes and customers receiving a portion of the Bank, designed to feed back one-third of the principal balance of the Bank to said customer classes and customers over the following eleven (11) months. Pursuant to the following paragraph, certain customers may elect an accelerated feedback of their portion of the Bank.

22. The Kroger Co., Huntington Sanitary Board, South Putnam Public Service District, and/or the members of WVEUG may request alternative feedback mechanism(s) designed to enable them to realize an accelerated feedback of their shares of the Bank. On condition that no alternative mechanism enables an electing customer to receive more than the shares of the Bank, plus interest up to the date of payout, which it would have received under the standard mechanism provided for in the preceding paragraph, the Companies are willing, after Commission approval of this Agreement, to negotiate reasonable mechanisms for accelerated feedback, subject to legal constraints and practical limitations.

23. In consideration of the Special Rate Mechanism discussed below, Century shall not be entitled to any share in the principal balance of the Bank or any interest accrued thereon.

24. The timing and particulars of the feed back of the residual balance of the Bank, plus interest, remaining after compliance with the preceding paragraphs of this

section, shall be as determined and directed by the Commission in the next ENEC proceeding filed by the Companies.

Recovery of Expenditures Related to the 765 kV Line and Scrubbers

25. APCo is currently engaged in the following extraordinary construction projects: (1) the Wyoming-Jacksons Ferry 765 kV Transmission Line; and (2) the retrofit of flue-gas desulfurization units ("scrubbers") on the Mountaineer generating plant and Units 1, 2 and 3 of the John Amos generating plant (collectively referred to as "the projects").

26. The Stipulating Parties adopt, with certain modifications, the CAD's proposal for rate increments in future ENEC proceedings. The Wyoming-Jacksons Ferry 765 kV line is to be provided electric plant in service ("EPIS") treatment at a 10.5% return on equity based on the construction work in progress ("CWIP") balance as of December 31, 2005, including projected depreciation, taxes and other fixed operating expense. The Wyoming-Jacksons Ferry line and each of APCo's planned scrubber projects will be afforded EPIS treatment at a 10.5% return on equity in succeeding ENEC proceedings after a given project has been placed in service, provided the project is in service no later than March 1st of the year the ENEC factor becomes effective. EPIS treatment will include the recovery of estimated fixed costs.

27. The Stipulating Parties agree that the Companies should be allowed to recover the construction expenditures and other costs related to the projects during the construction phase and, after the projects are classified as EPIS, in the following manner:

a. APCo shall accrue AFUDC on construction expenditures for each project, based on a 10.5% ROE. In each ENEC proceeding APCo shall be allowed to recover a return and associated taxes ("Return") on all CWIP expenditures along with accrued AFUDC made in connection with the projects through the end of the ENEC review period, December 31st of each year. Rates recovering such return ("construction surcharges") shall go into effect on July 1st of the next succeeding year as part of the ENEC.

b. The return on such CWIP and EPIS shall be based on:

i. the amount of equity, long term debt, short term debt and preferred stock in APCo's capital structure based on a thirteen month average as of December 31st of each year;

ii. a rate of return on equity capital of 10.5%, and a return on other capital (long term debt, short term debt and preferred stock) at the thirteen month average cost of such other capital component as of December 31st of each year.

c. CWIP balances earning a CWIP allowance would not be subject to the accrual of AFUDC. CWIP balances in excess of amounts earning a CWIP allowance shall continue to be subject to the accrual of AFUDC during the construction period. In addition to a return on CWIP existing at December 31st of each year, all projects that are transferred to EPIS by March 1st of the succeeding year, shall also be allowed to recover depreciation, property taxes and other fixed costs associated with such EPIS to be incurred over the next succeeding ENEC recovery period.

d. In succeeding ENEC proceedings, projects previously transferred to EPIS shall be allowed to recover a Return on EPIS balances net of accumulated depreciation as of December 31st of each year, along with depreciation, property taxes and other fixed costs.

e. The Stipulating Parties agree that the Companies shall be allowed to recover in rates effective July 28, 2006, a total of $23.21 million associated with CWIP expenditures on the projects as of December 31, 2005. The Stipulating Parties also agree that the $23.21 million allowance includes recovery of depreciation, property taxes and other fixed costs associated with the Wyoming-Jacksons Ferry 765 kV transmission line.

f. Construction surcharges and EPIS surcharges shall be established as part of the Companies' annual ENEC proceedings, but the costs and revenues associated with these construction surcharges and EPIS surcharges shall not be subject to deferred accounting for regulatory purposes. The Stipulating Parties acknowledge that the construction and EPIS surcharges established in this case are calculated for the various customer classes based on the twelve coincident peak (12 CP) demand allocator.

Base Rates

28. The Stipulating Parties agree that effective July 28, 2006, the Companies' current base rates shall be reduced by $18,433,000 on an annual basis, based on a return on equity of 10.5%. Exhibit D, attached hereto and incorporated herein, is a cost of service showing the derivation of the Companies' stipulated base rate revenue requirement. Although no Stipulating Party agrees with each and every item in the attached cost of service, all parties agree that the overall cost of service is reasonable, and should be adopted by the Commission.

29. The base rates provided for in this Agreement reflect the recovery of the amortization of the Asset Retirement Obligation ("ARO") as proposed by the Companies in this case.

30. The rate changes with respect to base rate decreases, the feedback of the Bank, ENEC increases, and the 2006 construction surcharges shall be allocated among the customer classes as shown on Exhibit E attached hereto and incorporated herein.

Reliability Expenditures

31. The Companies shall collectively expend an average of $18,660,000 annually in each calendar year, 2007, 2008, and 2009, for measures designed to maintain and enhance reliability of service (i.e. right-of-way vegetation management and asset management activities). This annual sum constitutes an addition of $4.782 million over 2004 test year levels.

32. The Stipulating Parties agree that if APCo fails to earn a rate of return on common equity ("ROE") of at least 10.5% on a per books West Virginia retail jurisdictional basis during any of the calendar years, 2007, 2008, or 2009, APCo shall be entitled to defer an amount for T&D reliability expenditures sufficient to enable its ROE to equal 10.5%, up to a collective maximum annual deferral of $4.782 million. At its election, APCo shall be allowed to obtain appropriate recovery of any such deferrals in succeeding ENEC or base rate case(s) following such deferrals.

33. If the Companies intend to include in a case the issue of recovery of any deferral referred to in the preceding paragraph, the Companies will give prior notice to the other Stipulating Parties along with a calculation showing the derivation of the deferral. The other Stipulating Parties shall be free to take whatever position they deem appropriate concerning the appropriate amount of such recovery based on the ROE earned by APCo, the proper calculation of ROE, and the sums expended on T&D reliability measures.

34. The Companies recognize that it is their responsibility, as it is the responsibility of all public utilities in this State, under W Va. Code §24-3-1, to provide a reasonable level of reliable electric service to their customers. Nothing in this Agreement is intended to (1) relieve or limit the Companies' obligation to expend the funds needed to discharge this responsibility or (2) absolve the Companies of their legal duty as set forth in W. Va. Code §24-3-1.

Depreciation Rates

35. Effective July 1, 2006, APCo's West Virginia depreciation rates shall be modified in accordance with the schedule of depreciation rates attached hereto as Exhibit F and incorporated herein by reference.

36. Notwithstanding the provisions of this Agreement by which the Stipulating Parties agree to changes in the Companies' depreciation rates as a significant element of the Settlement, the Staff wishes to make clear that its agreement is due to the unique circumstances of this case. The Staff holds firm to its position that depreciation rate issues should not be part of any application filing in a base rate case, but should be addressed by a separate filing made pursuant to Rule 20 of the Commission's Rules of Practice and Procedure.

Special Rate Mechanism for Century Aluminum

37. The Stipulating Parties agree that Century provides important contributions to the economy of West Virginia in terms of good-paying industrial jobs, tax revenues, and other factors. In light of those contributions, the electric-energy-intensiveness of Century's operations, and the competitiveness of Century's industry, the Stipulating Parties agree that it is appropriate to undertake an experiment in devising and

applying a special rate mechanism to Century that is linked to the commodity price of aluminum and that compensates the Companies' ratepayers for the risks which the experiment poses for them. If approved by the Commission, the special rate mechanism experiment shall be implemented August 1, 2006 and shall operate as follows:

a. Century currently pays a rate equivalent to $27.16 per Mwh (the "current rate"). Subject to subpart c hereof, on and after August 1, 2006, Century shall pay each month to APCo the lower of the cost-based rate applicable to Century resulting from this or any future rate proceeding, or the current rate plus a surcharge based on the simple average daily price of aluminum for the month as quoted on the London Metal Exchange and as published by Reuters ("the LME price"). These surcharges are set forth in Exhibit G attached hereto and incorporated herein.

b. Each month the current price plus the surcharge will be greater than or less than the total rate responsibility allocated to Century. ("the otherwise applicable rate"). Century and APCo will keep a running cumulative balance of these monthly surpluses and deficits ("the Century Bank"). If in any month APCo does not receive adequate revenue under the experimental rate mechanism, including any payments from the Century Bank, equivalent to that which would be due from the otherwise applicable rate, APCo will be authorized to record a regulatory asset in the amount of such under-recovery for future recovery from the Companies' customers, as a part of its ENEC, at the conclusion of the experiment, pursuant to subpart d hereof. Century shall maintain a monthly accounting record of the Century Bank, subject to audit by the Companies and the Public Service Commission, showing the monthly and cumulative surplus or deficit.

c. As security for the Companies and other ratepayers, a portion of the monthly payments based on the current rate plus the applicable surcharge will be retained by APCo, up to $1,000,000, and will be paid by Century in months when the current price plus the applicable surcharge exceeds the otherwise applicable rate. That amount will be considered part of the Century Bank, although held by APCo as a regulatory liability to be credited to customers in accordance with subpart d hereof. At Century's option, the $1,000,000 amount can be paid to APCo in equal monthly payments during the first year of the experimental rate program. APCo will accrue interest on the amount collected under this subpart at the Commission's approved interest rate on deposits.

d. The experimental rate program will be reviewed by the Commission during the 2009 ENEC proceeding. If the experimental rate program is extended, any existing Century Bank balance will roll forward into the new plan. If the experimental rate program is terminated, Century will have no further obligations to pay or rights to receive payments under this program. If the program is terminated, the Companies will reflect any regulatory asset and/or regulatory liability as a net charge or credit to all customers, excluding Century, in the next ENEC proceeding.

e. If the Commission approves this experimental rate program in all its particulars, Century and APCo will negotiate a detailed contract to implement this experimental rate program and will file such contract with the Commission under Rule 39 of the Commission's Rules. If the Commission does not approve this experimental rate program in all its particulars, APCo shall have no obligation to provide service to Century other than at its otherwise applicable rate.

RS Rate Design

38. The increase allocated to the residential (RS) class shall be recovered from the usage blocks in that rate class. There will be no increase in the customer charge and no imposition of a separate minimum bill.

LGS Rate Design

39. The Stipulating Parties agree to modify the demand/energy split for the LGS rate schedule to reflect a demand charge at 80% of full cost. The base rate revenue reduction applicable to the LGS class shall be applied 80% to energy and 20% to demand. Customer migrations between MGS and LGS shall not be permitted until the next rate case, except in the case of material changes in load which result in a dramatic change in a customer's usage characteristics. However, the Companies agree that the accounts of Huntington/South Putnam and the water and sewer utilities that have supported the participation of Huntington/South Putnam in this proceeding (which are listed on Exhibit H attached hereto and incorporated herein) will have been placed on the appropriate MGS or LGS rate schedule for which they qualify prior to July 28, 2006.

Low-Income Weatherization Projects

40. For the next three years, the Companies shall make a collective annual contribution of $250,000 to the West Virginia Governor's Office of Economic Opportunity to be administered for WVCAP, to be used for low-income residential weatherization projects. The scheduling of the payments and the usage of the funds shall be arranged between the Companies and OEO weatherization staff on behalf of WVCAP.

Terms and Conditions of Service
and Requested Rule Waivers

41. The Companies have withdrawn their requests for a partial waiver of Electric Rule 4.2.1.a, for a grant of flexibility and discretion to require additional security deposits of non-residential customers, for the institution of fixed non-refundable charges for temporary service, and for a tariff modification concerning customer liability.

42. The Stipulating Parties agree that the Companies should be granted partial waivers of Electric Rules 4.8.1.a.F and 4.8.1.a H to enable them to defer non-emergency reconnections of service from times of darkness to times of daylight and authorize their field personnel to decline to accept cash payments to forestall disconnections of service for non-payment.

43. The Companies shall be authorized to impose a 1% delayed payment charge ("DPC") on a current bill owed by customers served under Rate Schedules R.S. and R.S. – T.O.D. if not paid "by the next scheduled read date." The DPC may be assessed only once on a given current bill. Before this new DPC is implemented, the Companies shall be required to give notice by bill message or bill insert to at least the customer classes affected, in two successive billing months, of the basic facts about the new DPC. The Companies shall change the proposed language in their tariffs about the point at which an account becomes subject to a DPC assessment for balances not paid "by the next bill preparation date" to "by the next scheduled read date." The approval and implementation of this new DPC shall have no effect on the DPCs already in operation under other rate schedules of the Companies.

Base Rate Case Filing Commitment

44. The Companies commit to filing a base rate case, predicated on a 2009 test year, by no later than the second quarter of 2010.

General Matters

45. The Stipulating Parties agree to waive their right to conduct in this proceeding any examination of the witnesses of any other party to this Agreement, except that the parties may ask clarifying questions concerning this Agreement.

46. This Agreement is entered into subject to the acceptance and approval of the Commission. It results from a review of any and all filings in this proceeding, the Stipulating Parties' prefiled testimony and exhibits, and extensive discovery and discussion. It reflects substantial compromises by the Stipulating Parties and the withdrawal of their respective positions asserted in this case, and is being proposed to expedite and simplify the resolution of this proceeding and other outstanding matters. It is made without any admission or prejudice to any positions which any party might adopt during subsequent litigation. The Stipulating Parties adopt this Agreement as being in the public interest, without adopting any of the compromise positions set forth herein as ratemaking principles applicable to future ENEC proceedings, Rule 42 proceedings, or other regulatory proceedings, except as expressly provided herein. The Stipulating Parties acknowledge that it is the Commission's prerogative to accept, reject, or modify any stipulation. However, in the event that this Agreement is rejected or modified by the Commission, it is expressly understood by the Stipulating Parties that they are not bound to accept this Agreement as modified or rejected, and may avail themselves of whatever

rights are available to them under law and the Commission's Rules of Practice and Procedure.

WHEREFORE, the Stipulating Parties (except the Staff with regard to the one element identified in Paragraph 15) on the basis of all the foregoing, respectfully request that the Commission make appropriate Findings of Fact and Conclusions of Law adopting and approving the Joint Stipulation and Agreement for Settlement in its entirety, including specifically Exhibits A through H.

Respectfully submitted this 24th day of April, 2006.

Respectfully Submitted

APPALACHIAN POWER COMPANY and WHEELING POWER COMPANY

By: ______________________

STAFF OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: ______________________

CONSUMER ADVOCATE DIVISION OF THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

By: ______________________

WEST VIRGINIA ENERGY USERS GROUP

By: ____________________

CENTURY ALUMINUM OF WEST VIRGINIA, INC.

By: ____________________

THE KROGER CO.

By: ____________________

HUNTINGTON SANITARY BOARD AND SOUTH PUTNAM PUBLIC SERVICE DISTRICT

By: ____________________

WEST VIRGINIA COMMUNITY ACTION PARTNERSHIP

By: ____________________

{R0129314.1}

EXHIBIT A

Revised Section 2: Actual Period Ended December 31, 2004

ENEC Rates

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
TWELVE MONTHS ENDED 12/31/2004
INCLUDES DATA CORRECTIONS

CUSTOMER CLASS			ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS			1.612	
RS -TOD / RS-LM-TOD				
	ON-PEAK		1.617	
	OFF-PEAK		1.106	
SWS			1.619	
SGS			1.526	
SGS - LM-TOD				
	ON-PEAK		1.526	
	OFF-PEAK		1.169	
SS	-SEC		1.107	1.342
	-PRI		1.076	1.303
	-AF		1.539	
MGS	-SEC		1.107	1.159
	-PRI		1.077	1.125
	-SUBTRAN		1.057	1.095
	-TRANS		1.041	1.077
	-AF		1.541	
GS-TOD				
ON-PEAK	-SEC		1.864	
OFF-PEAK	-SEC		1.256	
ON-PEAK	- PRI		2.040	
OFF-PEAK	-PRI		1.318	
LGS	-SEC		1.106	1.660
	-PRI		1.076	1.612
	-SUBT		1.057	1.570
	-TRANS		1.041	1.544
LCP	-SEC		1.106	1.597
	- PRI		1.076	1.550
	- SUBT		1.057	1.511
	- TRANS		1.040	1.486
IP	-SEC		1.105	1.884
	- PRI		1.075	1.829
	- SUBT		1.057	1.782
	- TRANS			
		All Other	1.040	1.752
		SPECIAL CONTRACT I	1.040	1.752
		SPECIAL CONTRACT G	1.040	1.769
	SPECIAL CONTRACT H		1.040	2.212
OL			1.105	
SL			1.105	

SPECIAL CONTRACT A			
	FIRM POWER	1.040	1.752
	INTERRUPTIBLE DEMAND		1.162
	P1	1.040	
	P2	1.040	
	P2.5	1.040	
	P3	1.040	
	P4	1.040	
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		0.913
	P1	1.040	
	P2	1.040	
	P2.5	1.040	
	P3	1.040	
	P4	1.040	
	46 KV SERVICE		
	P1	1.055	
	P2	1.055	
	P2.5	1.055	
	P3	1.055	
	P4	1.055	
SPECIAL CONTRACT C			
	P1	1.096	
	P2	1.275	
	P3	12.752	
	P4	7.555	
SPECIAL CONTRACT D			
	FIRM POWER	1.054	1.777
	ON-PEAK DEMAND		0.644
	OFF-PEAK DEMAND EXCESS		0.118
	SHOULD. PEAK DEM. EXCESS		0.379
	INTERR. ENERGY	1.040	
SPECIAL CONTRACT E			
	-SEC		
	ON-PEAK	1.653	
	OFF-PEAK	1.385	
	SHOULDER PEAK	1.447	
	-PRI		
	ON-PEAK	1.674	
	OFF-PEAK	1.338	
	SHOULDER PEAK	1.418	
SPECIAL CONTRACT F			
	FIRM POWER	1.057	2.048
	BACK-UP POWER	1.057	0.205
	MAINTENANCE	1.094	

FLOODWALL ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.

EXHIBIT B

Revised Section 1

Attachment 1
Page 1 of 3

Revised Section 1: Proposed Period Ending December 31, 2006

ENEC Rates

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
PROPOSED EXPANDED NET ENERGY COST (ENEC) RATES
2006 ENEC FACTOR
INCLUDES DATA CORRECTION & INCLUDES CEREDO

CUSTOMER CLASS		ENEC ENERGY FACTOR ¢/KWH	ENEC DEMAND FACTOR $/KW
RS		1.932	
RS -TOD / RS-LM-TOD			
	ON-PEAK	1.938	
	OFF-PEAK	1.407	
SWS		1.943	
SGS		1.846	
SGS - LM-TOD			
	ON-PEAK	1.846	
	OFF-PEAK	1.473	
SS	-SEC	1.408	1.387
	-PRI	1.369	1.347
	-AF	1.853	
MGS	-SEC	1.408	1.198
	-PRI	1.370	1.162
	-SUBTRAN	1.345	1.132
	-TRANS	1.325	1.113
	-AF	1.856	
GS-TOD			
ON-PEAK	-SEC	2.339	
OFF-PEAK	-SEC	1.406	
ON-PEAK	- PRI	2.554	
OFF-PEAK	-PRI	1.367	
LGS	-SEC	1.407	1.715
	-PRI	1.369	1.665
	-SUBT	1.345	1.622
	-TRANS	1.325	1.595
LCP	-SEC	1.407	1.649
	- PRI	1.369	1.601
	- SUBT	1.345	1.580
	- TRANS	1.323	1.534
IP	-SEC	1.406	1.948
	- PRI	1.368	1.890
	- SUBT	1.344	1.842
	- TRANS		
	All Other	1.323	1.811
SPECIAL CONTRACT I		1.323	1.811
SPECIAL CONTRACT G		1.323	1.834
SPECIAL CONTRACT H		1.324	2.269
OL		1.406	
SL		1.406	

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
PROPOSED EXPANDED NET ENERGY COST (ENEC) RATES
2006 ENEC FACTOR
INCLUDES DATA CORRECTION & INCLUDES CEREDO

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
SPECIAL CONTRACT A			
	FIRM POWER	1.323	1.811
	INTERRUPTIBLE DEMAND		1.852
	P1	1.323	
	P2	1.323	
	P2.5	1.323	
	P3	1.323	
	P4	1.323	
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		0.945
	P1	1.323	
	P2	1.323	
	P2.5	1.323	
	P3	1.323	
	P4	1.323	
	46 KV SERVICE		
	P1	1.343	
	P2	1.343	
	P2.5	1.343	
	P3	1.343	
	P4	1.343	
SPECIAL CONTRACT C			
	P1	1.383	
	P2	1.621	
	P3	16.208	
	P4	11.716	
SPECIAL CONTRACT D			
	FIRM POWER	1.3410	1.837
	ON-PEAK DEMAND		0.659
	SHOULD. PEAK DEM.		0.391
	OFF-PEAK DEMAND		0.121
	INTERR. ENERGY	1.3230	
SPECIAL CONTRACT E			
	-SEC		
	ON-PEAK	1.987	
	OFF-PEAK	1.665	
	SHOULDER PEAK	1.740	
	-PRI		
	ON-PEAK	2.001	
	OFF-PEAK	1.593	
	SHOULDER PEAK	1.695	
SPECIAL CONTRACT F			
	FIRM POWER	1.344	2.120
	BACK-UP POWER	1.344	0.212
	MAINTENANCE	1.382	

FLOODWALL ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.

EXHIBIT C

Baron Exhibit__(SJB-1R)
(Modified per Stipulation)

Appalachian Power Company
WVEUG Proposal to
Distribute ENEC Overrecovery
Case No. 05-1 278-E-PC-PW4ZT

Tariff	Voltage	WVEUG Settlement (total bank balance)	WVEUG Settlement (1st year 1/3rd feedback)
RS		27,899,511	9,299,837
SWS		269,846	89,948
SGS		1,222,031	407,344
SS	Sec.	803,504	267,835
SS	Pri.	46,266	15,422
SS	Ath. Field	10,983	3,661
		880,752	286,917
MGS	Sec.	3,252,179	1,084,060
MGS	Pri.	364,330	121,443
MGS	Subtr.	21,653	7,218
MGS	Trans.	-	-
MGS	Ath. Field	6,011	2,004
		3,644,173	1,214,724
GS-LMTOD	Sec-peak	35,890	11,963
GS-LMTOD	Sec-off	19,069	6,363
GS-LMTOD	Pri -peak	22,663	7,554
GS-LMTOD	Pri- off	8,443	2,814
		86,066	28,695
LGS	Sec.	3,236,546	1,078,849
LGS	Pri.	493,058	164,353
LGS	Subtr.	12,999	4,333
LGS	Trans.	-	-
		3,742,603	1,247,534
LCP	Sec.	250,008	83,336
LCP	Pri.	1,407,623	469,208
LCP	Subtr.	2,411,049	803,683
LCP	Trans.	723,990	241,330
		4,792,671	1,597,557
IP	Sec.	201,991	67,330
IP	Pri.	2,262,228	754,076
IP	Subtr.	2,043,528	681,176
IP	Trans.	1,251,161	417,054
		5,758,907	1,919,636
SPECIAL A		-	-
SPECIAL B		437,195	145,732
SPECIAL C		4,244	1,415
SPECIAL D		418,383	139,461
SPECIAL E		9,996	3,332
SPECIAL F		78,987	26,329
SPECIAL G		1,217,003	405,668
SPECIAL H		-	-
SPECIAL I		552,492	184,164
OL		137,008	45,669
SL		76,093	25,364
TOTAL		51,207,981	17,069,327

EXHIBIT D

Exhibit ________

Appalachian Power Company and Wheeling Power Company
Case No. 05-1278-E-PC-PW-42T
Revenue Requirement Calculation for Settlement

	Settlement
Weighted Cost of Capital	7.601%
Return on Equity	10.50%
Rate Base	1,657,541,508
Return on Rate Base	125,996,586
Federal Taxes	31,499,147
State Taxes	11,969,676
Operation & Maintenance Expense	727,297,676
Depreciation Expense	79,833,661
Taxes Other Than Income	53,803,432
Total Expenses	904,403,591
Revenue Requirement	1,030,400,177
Going Level Revenues	1,048,473,441
Subtotal	(18,073,264)
Additional Uncollectibles	(65,064)
Additonal B&O	(291,702)
Revenue Increase/(Decrease)	(18,430,030)

EXHIBIT E

Appalachian Power Company
Revenue Changes by Tariff Class
Case No. 05-1278-E-PC-PW-42T

Tariff	Base Rate Decrease	ENEC Increase	Construction Surcharge	Net Revenue Change	ENEC Bank Amortization	Net Impact
RS	$2,422,695	$18,735,076	$9,321,136	$30,478,907	($9,299,837)	$21,179,070
SWS	($49,693)	$284,837	$141,870	$377,015	($89,948)	$287,066
SGS	($313,432)	$794,042	$328,594	$809,203	($407,344)	$401,860
SS	($202,033)	$1,068,225	$513,713	$1,379,905	($286,917)	$1,092,988
MGS	($4,769,035)	$4,649,496	$2,168,946	$2,049,407	($1,243,420)	$805,987
LGS	($3,846,810)	$4,846,586	$1,921,120	$2,920,896	($1,247,534)	$1,673,362
LCP	($4,361,852)	$6,185,894	$2,461,890	$4,285,933	($1,597,557)	$2,688,376
IP	($3,826,607)	$7,613,388	$2,655,841	$6,442,622	($1,919,636)	$4,522,986
SPECIAL A	($8,117)	$136,538	$24,304	$152,725	$0	$152,725
SPECIAL B	($203,009)	$596,431	$190,164	$583,586	($145,732)	$437,854
SPECIAL C	($8,105)	$6,739	$256	($1,110)	($1,415)	($2,525)
SPECIAL D	($392,810)	$594,700	$139,778	$341,668	($139,461)	$202,207
SPECIAL E	$94	$11,929	$4,482	$16,505	($3,332)	$13,173
SPECIAL F	($40,547)	$107,780	$35,765	$102,998	($26,329)	$76,669
SPECIAL G	($508,467)	$1,205,428	$354,502	$1,051,463	($405,668)	$645,796
SPECIAL H	($1,125,428)	$8,121,578	$2,705,226	$9,701,376	$0	$9,701,376
SPECIAL I	($431,249)	$742,623	$242,311	$553,685	($184,164)	$369,521
				$0		
OL	($560,767)	$222,218	$0	($338,549)	($45,669)	($384,218)
SL	($204,858)	$87,575	$0	($117,283)	($25,364)	($142,647)
TOTAL	($18,430,000)	$56,011,083	$23,209,899	$60,790,982	($17,089,327)	$43,721,655

EXHIBIT F

Exhibit No ______

Appalachian Power Company
Depreciation Rates
Case No. 05-1278-E-PC-PW-42T

	Current Rates	New Rates
Steam Production		
Mountaineer	2.64%	1.93%
Amos	2.79%	2.98%
Kanawha River	3.88%	1.19%
Sporn	4.86%	1.53%
Clinch River	3.48%	3.00%
Glyn Lyn 5	0.92%	4.99%
Glyn Lyn 6	3.71%	4.00%
Hydro Production		
Claytor	2.71%	1.17%
Byllesby	2.90%	2.89%
Buck	3.21%	2.95%
Niagara	2.31%	2.41%
Ruesens	1.69%	1.64%
Leesville	2.51%	1.21%
London	1.65%	1.85%
Marmet	1.65%	1.91%
Winfield	1.65%	1.76%
Smith Mountain	3.39%	1.29%
Other Production		
Central Maintenance	4.02%	2.07%
Central Machine	4.02%	2.10%
Little Broad Run	4.02%	1.76%
Transmission Plant	2.21%	1.63%
Distribution Plant	3.20%	3.37%
General Plant	3.14%	1.80%

EXHIBIT G

SCHEDULE B
CENTURY ALUMINUM OF WEST VIRGINIA, INC.
MAXIMUM MONTHLY SURCHARGE [1]

MONTHLY LME PRICE [2]	MAXIMUM MONTHLY SURCHARGE [3]
$2200/tonne or less ($0.998/lb or less)	Zero
$2300/tonne ($1.043/lb)	1.87 mills/kWh
$2400/tonne ($1.089/lb)	3.73 mills/kWh
$2500/tonne ($1.134/lb)	5.56 mills/kWh
$2600/tonne ($1.179/lb)	7.43 mills/kWh
$2700/tonne ($1.225/lb)	9.30 mills/kWh
$2800/tonne ($1.270/lb)	11.16 mills/kWh
$2900/tonne ($1.315/lb)	12.99 mills/kWh
$3000/tonne ($1.361/lb)	14.86 mills/kWh

(1) The **Maximum Monthly Surcharge** shall remain in effect for the full term of this agreement, unless modified by Century Aluminum and approved by the PSC of West Virginia.

(2) The **LME PRICE** shall be defined as the daily cash settlement for high grade aluminum, as quoted on the London Metal Exchange (as published by Reuters). The monthly LME Price shall be the simple average of the daily prices.

(3) For LME prices not shown, the **Maximum Monthly Surcharge** may be interpolated between the points.

EXHIBIT H

PUBLICLY-OWNED SEWER AND WATER UTILITIES SUPPORTING INTERVENTION OF SOUTH PUTNAM PSD AND HUNTINGTON SANITARY BOARD THROUGH CONTRIBUTIONS UNDERWRITING EXPERT WITNESS AND ATTORNEY FEES

Bluewell Public Service District

Chelyan Public Service District

Culloden Public Service District

Fayetteville, Town of

Hodgesville Public Service District/
Tennerton Public Service District

Hurricane Water & Sanitary Board

Lavalette Public Service District

Logan County Public Service District

Oakvale Road Public Service District

Pea Ridge Public Service District

West Hamlin, Town of

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, page 10, lines 18 through 23.

a. Did Kentucky Power or AEP announce previously, in either 2005 or 2006, that a flue gas desulfurization ("FGD") system was going to be installed at Kentucky Power's Big Sandy generating station?

b. Explain why a FGD system for Kentucky Power's Big Sandy generating station was not referenced in Mr. McManus's testimony.

RESPONSE

a. Yes.

b. Since the public announcements, AEP's compliance plan has been revised and currently reflects a post-2010 in-service date for Big Sandy FGD. Since the in-service date was outside the scope of this proceeding, it was not included in this revised environmental plan.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, pages 12, 13, 22, 23, 25, and 26. Under the provisions of KRS278.183(1), a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products resulting from the production of energy by the burning of coal. For each of the projects listed below, explain in detail how the project satisfies the requirements of KRS278.183(1). Include in the response a discussion of how the project directly relates to the control of coal combustion wastes and by-products and a description of the features or characteristics of the project that qualifies it for inclusion in Kentucky Power's environmental compliance plan and eligible for recovery through the environmental surcharge.

a. Coal Blending projects at Amos Unit 3 and Mitchell Units 1 and 2.

b. Replacement of Transformer Rectifier Sets at Mitchell Units 1 and 2.

c. Limestone preparation, auxiliary pumping station, and river work grouped as a Plant Common Project at Amos Unit 3.

RESPONSE

a. As described on page 14 of the McManus Testimony, the installation of FGD technology allows greater flexibility in the range of coal quality that can be used at a controlled unit to meet emission requirements. In order to take advantage of this flexibility, and to achieve subsequent savings in fuel cost, improvements to the currrent coal handling systems are needed at some units. This project would not be undertaken absent the requirement to comply with current and future regulations under Title IV, 40 CFR 72-78 and the CAIR Program, 40 CFR 96.

b. As described on page 22 of the McManus Testimony, the transformer / rectifier sets (T/R sets) are designed specifically to provide high voltage necessary for proper operation of the electrostatic precipitator (ESP). The replacement is occurring for several reasons: 1) Safety and environmental issues regarding PCBs contained in the T/R sets at Mitchell will be eliminated, 2) particulate capture will improve as a result of adding increased power and sectionalization to the ESP, and 3) within the next 3 to 5 years under Title V, Mitchell Plant will be required to develop a Continuous Assurance Monitoring (CAM) Plan for its ESP. With high power levels, upgraded controls, and a demonstration of improved performance, Mitchell will be in a good position for developing a plan with the state of West Virginia.

c. Low cost and wide availability make limestone the most extensively used reagent in the utility industry. The installation of the limestone preparation area, auxiliary pumping station and river work are all associated and required for operation of Amos FGD. The limestone preparation work includes a limestone unloading area, limestone pile, limestone crushing, and limestone slurry mixing. The auxiliary pumping work includes the pumps and piping required to transport the limestone slurry to the landfill. The river work includes the additional barge cells needed to facilitate limestone deliveries on the river. These projects would not be undertaken absent the requirement to comply with current and future regulations under Title IV, 40 CFR 72-78 and the CAIR Program, 40 CFR 96.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, pages 17 and 18, and Exhibit JMM-1. Concerning the fuel switching project at Tanners Creek Unit 4:

a. Was a cost/benefit analysis performed concerning the fuel switching option? Explain the response.

b. If a cost/benefit analysis was not performed, explain in detail why such an analysis was not performed.

c. If a cost/benefit analysis was performed, explain how the cost of transportation for additional quantities of Powder River Basin coal was factored into the analysis.

d. If transportation costs were not included in a cost/benefit analysis, explain in detail why this factor was excluded.

RESPONSE

a. Please see attached pages 2 through 15.

b. Not applicable.

c. Transportation cost is figured in total fuel cost savings that is reflected in the capital improvement documentation. The reduced coal cost is equal to $0.12/Mbtu in 2006 to $0.26/MBtu in 2014 and beyond.

d. Not applicable.

WITNESS: John M McManus

AMERICAN® ELECTRIC POWER

Tanners Creek Unit 4 Fuel Blend Project Update

Presented to:

American Electric Power

Executive Council

December 2004

Presented by:
Michael Rencheck
Chuck Zebula
Bruce Braine

AMERICAN ELECTRIC POWER

TC4 PRB Fuel Blend Project

- Increase TC4 PRB Fuel Blend from 40% to 80% nominal
  - Reduce SO_2 Emissions by 21 ktons/year
  - Reduce NO_X Emissions by 500 tons/O_3 season (1,200 tons/year)
  - Reduce Coal Costs - \$0.12/Mbtu in 2006 to \$0.26/Mbtu in 2014 and beyond
- The Environmental Compliance Plan (MECO model) identified the Tanners Creek Unit 4 fuel switch as one of the least cost compliance options

AEP AMERICAN ELECTRIC POWER

Major Scope of Work

Boiler Requirements

- Restore Gas Tempering
- Water Cannons
- Slag & Soot Blower Upgrades
- Fine Grind Crushing
  - 98% thru a 4 mesh
- Economizer Hoppers
- Coal Feeder, Chute & Pipe Upgrades

Coal Handling

- Independent Storage & Reclaim for the PRB and Eastern Bituminous Coals
- New Crusher Station with 2 x 100% Crushers
- Dust Collection in Crusher House & Bunker Room
- Dust Suppression

AMERICAN ELECTRIC POWER

Alternatives Considered

- The emissions Compliance Plans have evaluated several alternatives such as the procurement of allowances on the open market and/or SCR and WFGD installations, but these alternatives are more costly.
- Off-Site blending options considered to reduce capital by $7M:
  - Blend at CCT – Adds $4-5M/yr transportation
  - Blend at Mt. Vernon CT – Adds $20M capital plus $8-9M/yr transportation
  - Layer Load barges at Mt. Vernon CT – Adds $3-4M/yr transportation

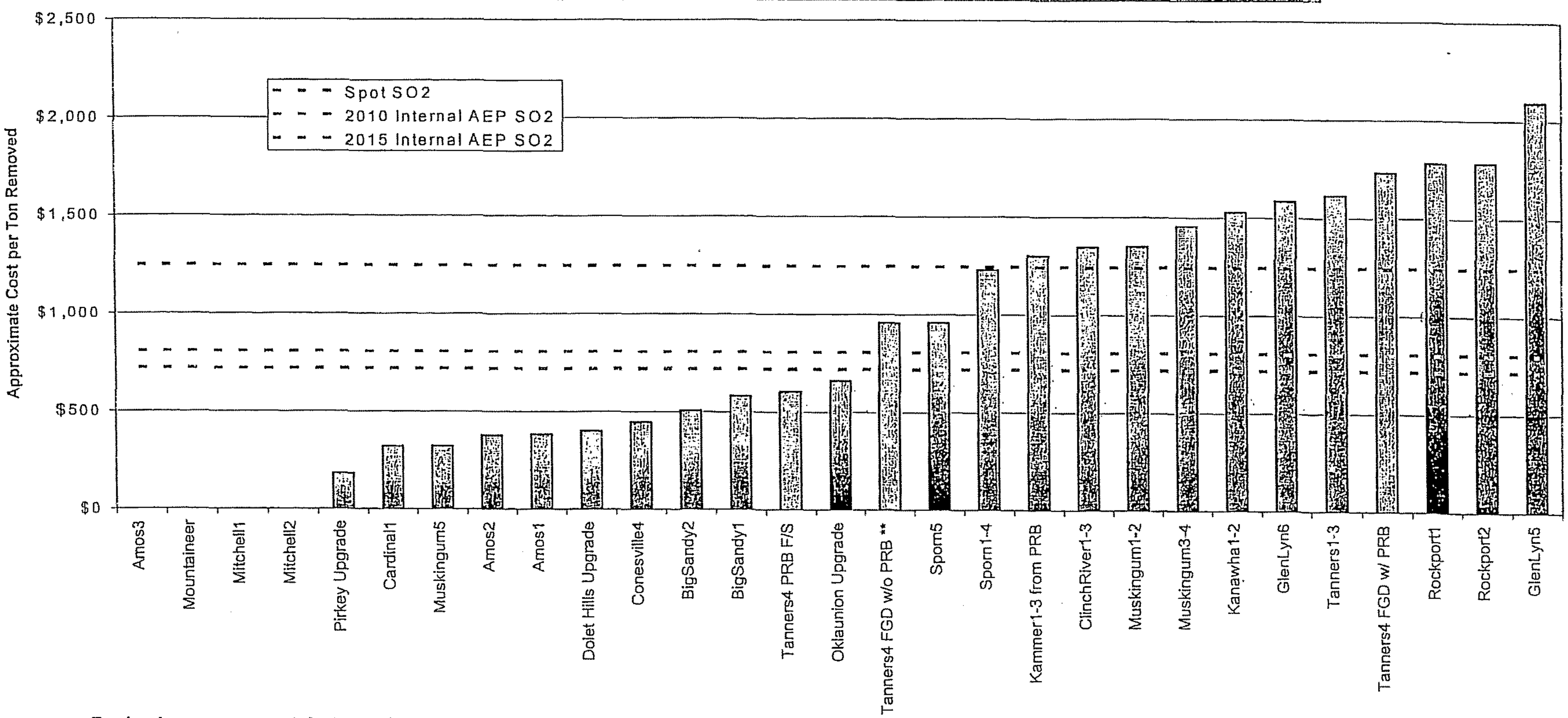
AMERICAN ELECTRIC POWER

MECO System-Wide Analysis

- MECO has elected to switch to PRB blend at Tanners Creek 4 in all scenarios and sensitivity analyses performed.
- Switch to PRB blend has the advantage of being a relatively "quick" source of SO_2 reductions (within 12 months). In MECO system-wide studies, it is selected in the first year assumed available.
- Decision remains robust at switching costs of $190/kw ($95 million)
- Static dollar-per-ton removed analysis shows PRB blend comparable in cost to previously identified "Tier 1" and "Tier 2" scrubber decisions (see next slides)
- $/ton SO_2 removed are well below spot and expected future SO_2 market allowance prices

AEP AMERICAN ELECTRIC POWER

Total AEP Scrubber and Fuel Switching Approximate Cost per Ton Removed (Incl. Hg Co-Benefit Credit)



Fuel prices represent Oct. 2004 annuity projections from Commercial Ops Trading Group. Baseline SO2 emission rates are October 2004 actual YTD. All other inputs (e.g. capital costs) are from Aug. 2004 quarterly review and are currently being updated. These updates could have a significant impact on the representative cost per ton at any given facility. A revised chart will be circulated reflecting these changes as soon as possible. Model assumes static 80% cap factor for facilities 500MW+. TC4 and Clinch River are assumed to be 65%. All other cap factors are assumed to be 55%. Capital charge rate of 14.5% accounts for favorable tax depreciation & assumes 10-year amortization. Mercury co-benefit is derived from internal compliance cost from Aug. 2004 MECO runs (approx. $60,000/lb)

Note: Given the significantly lower cost per ton of the PRB fuel switch, the "Tanners Creek 4 w/o PRB" cost per ton is only relevant in scenarios that exclude PRB as a fuel switch option.

AEP AMERICAN® ELECTRIC POWER

Approximate Cost Per Ton Estimates: Key Caveats

- All major inputs, except scrubber capital, reflect the latest available information (October 2004). FGD capital costs are currently being revised and thus earlier (August 2004) estimates are included in this analysis.
- Analysis is static (e.g. single capacity factor), which is appropriate for understanding the ***relative*** costs of various scrubbers and fuel switches at a certain point in time. A more dynamic analysis is needed, such as that done directly in the MECO model, to evaluate system-wide compliance decisions (including shifts in dispatch, mercury co-benefits, interactions with NOx controls, overall emission allowance balances etc.)
- Analysis represents estimates for decisions in 2008. This was done to analyze fuel switching and scrubbing decisions on a comparable basis. Dollar per ton removed would be different at varying points in time.

AMERICAN ELECTRIC POWER

Risks of Not Performing Work

- The SO_2 reductions for this project (21* ktons/year) will need to be realized by other means – more expensive alternatives, market
- Leaves asset exposed to higher dispatch cost as SO_2 prices rise (currently $12/MWHr)
- Delaying of the project de-couples it from the existing large outage and delays or prevents earning SO_2 reductions prior to 2010** (proposed regulatory change)

* Could be higher depending on capacity factor and blend ratio (20-30 ktons/year)

** Assumes CAIR rules as proposed where pre-2010 banked credits are valued at 1:1 rather than 2 allowances:1 ton emissions

AEP AMERICAN ELECTRIC POWER

Project Cost Summary

Equipment & Materials	$23,657,108
Labor & Supervision	$38,858,365
Direct Overheads	$11,958,933
Sub-Total	**$74,474,406**
Contingency	$7,447,441
Total Direct Costs	**$81,921,847**
Indirect Overheads	$7,544,027
Total	**$89,465,874**
Phase 1 Actual Costs	$1,171,608
Total CI Value	$90,637,482

AMERICAN ELECTRIC POWER

Project Economic Analysis

	Results (Rising SO_2 Prices to $1,608/ton in 2020)		
Modeling Methodology	15-Year IRR (%)	15-Year NPV ($*000)	Simple Payback (Years)
Economic Model	14.5%	$42,400K	6.3 yr
AEP Pool Effect (Shareholders only)	9.4%	$8,753K*	8.1 yr

SO_2 Removal Cost is about $750/ton based on 16.5% annual.
Capital Recovery for $89 million capital plus $1.3 million annual.
O&M divided by 21,000 tons/yr SO_2 removal.
* The weighted average cost of capital (discount rate) for AEP is 7.9% (e.g. NPV = 0 when IRR = 7.9%).

AEP AMERICAN ELECTRIC POWER

Project Economic Analysis

Sensitivity Cases (Mutually Exclusive)

- For each 10% change in Capital Cost, IRR changes by about 1.5%
- For each 0.1 Lbs change in SO_2 emission rate, IRR changes by about 0.7%.
- For Reduction in Off-Peak Night Prices by \$3/MWh and Weekend Prices by \$6/MWh (Based on PJM Clearing Prices), IRR changes by about 0.5%.
- For each 0.01 Lbs change in NOx emission rate, IRR changes by about 0.2%.

Project Economic Analysis

- Unit Dispatch / Capacity Factors
  - Assumed 15-yr average Capacity Factor without PRB Conversion – 72.5%
    - After project execution, Unit can be cycled between 300 MW (net) and full load
    - After project execution, Unit will have AGC capability
  - Assumed 15-yr average capacity factor with PRB Conversion – 78.9%
    - PRB conversion will eliminate $12/MWH SO_2 dispatch penalty
  - Anticipate no reduction in assumed Capacity Factors due to PJM experiences to date
    - Unit is currently dispatched at base load due to LP Turbine problems

AMERICAN ELECTRIC POWER

Project Economic Analysis

- EFOR
  - Unit currently has an EFOR of 9.5% year to date.
  - Projected EFOR after capital improvements is 8%
    - Benchmarked based on other PRB burning cyclone units that have made similar capital upgrades.
      - Sioux Station currently has a 5% EFOR
    - Anticipate no impact due to PRB conversion
- Analysis Period
  - 15-year life cycle was assumed in the economic analysis due to the capital improvements being implemented
  - The PRB Conversion will not have a negative impact to this assumption

AEP AMERICAN® ELECTRIC POWER

Recommendation

- We recommend to proceed with the TC4 Fuel Blend Project for the following reasons:
  - The project provides annual SO_2 reduction of 21,000 tons.
  - The project has been selected by the MECO model as one of the least cost compliance options.
  - Immediate approval of the project enables the work to be coupled with the 20-week Fall 2005 outage and eliminates the need for another long outage to perform the tie-in work.

Kentucky Power Company

REQUEST

On pages 17 and 18 of the McManus Testimony is a discussion of a fuel-switching project at Tanners Creek Unit 4 and a statement concerning reductions in sulfur dioxide and nitrogen oxide ("NOx") emissions at that generating station. Exhibit JMM-1 does not include a listing for a fuel switching project at Tanners creek Unit 4, but instead lists a coal blending project at Tanners Creek Common that was done in order to comply with the NOx State Implementation Plan Call. In addition, Exhibit 1 to the Application does not reference a fuel-switching project at Tanners Creek Unit 4, but instead lists the coal-blending project.

a. Resolve this apparent conflict between Mr. McManus's testimony and his Exhibit JMM-1 and Application Exhibit 1.

b. If the project to be included in Kentucky Power's environmental compliance plan is for Tanners Creek Common and a coal-blending project, provide a discussion of this project.

RESPONSE

a. As previously referenced on page 17 of John McManus's testimony, the fuel switch project should be titled as Tanner's Creek Unit 4 Coal Blending Project. The scope of the coal blending project included engineering, design, equipment and materials procurement, construction, start-up and commissioning to allow Unit 4 to change its fuel blend from a 40% PRB / 60% Eastern bituminous coal blend to an 80% PRB / 20% Eastern bituminous coal blend, with provisions to stage PRB levels up to 100%.

b. The Tanner's Creek Unit 4 Coal Blending project is only applicable to Unit 4 and Exhibit JMM-1 has been corrected to reflect this. See attachment for revised Exhibit JMM-1.

WITNESS: John M McManus

EXHIBIT JMM-1

REVISED September 8, 2006

Kentucky Power Company
AEP Pool Surplus Companies
Investment in Environmental Facilities

Generating Unit	Project Description	In-Service Date	New Facilities Cost ($1000s)	Applicable CAA Program
Amos Unit 3	FGD	4Q - 07	$346,121	Title IV Acid Rain/CAIR Program
Amos Unit 3	Balance Draft Conversion	4Q - 07	$39,923	Title IV Acid Rain/CAIR Program
Amos Unit 3	Controls Modernization	4Q - 07	$14,141	Title IV Acid Rain/CAIR Program
Amos Unit 3	Steam Generator Modifications	4Q - 07	$6,091	Title IV Acid Rain/CAIR Program
Amos Unit 3	SO3 Mitigation	4Q - 07	$14,066	NOx SIP Call
Amos Unit 3	FGD Purge Stream Water Treatment System	4Q - 07	$9,400	Title IV Acid Rain/CAIR Program
Amos Unit 3	Plant Common	4Q - 07	$90,797	Title IV Acid Rain/CAIR Program
Amos Unit 3	Coal Blending Station	4Q - 07	$5,740	Title IV Acid Rain/CAIR Program
Amos Units 1, 2, & 3	Landfill	4Q - 07	$33,263	Title IV Acid Rain/CAIR Program
Amos Unit 3	Precip Modification	4Q - 07	$93,365	Title I National Ambient Air Quality Standards
Cardinal Unit 1	FGD	4Q - 07	$216,748	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	Controls Modernization	4Q - 07	$5,930	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	Steam Generator Modifications	4Q - 07	$6,971	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	Balance Draft Conversion	4Q - 07	$30,530	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	FD Fan Modification	4Q - 07	$1,763	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	FGD Purge Stream Water Treatment System	4Q - 07	$12,821	Title IV Acid Rain/CAIR Program
Cardinal Unit 1	SO3 Mitigation	4Q - 07	$7,292	NOx SIP Call
Cardinal Unit 1	Catalyst Replacement	4Q - 07	$3,606	NOx SIP Call
Cardinal Unit 1	Landfill	2Q - 08	$15,703	Title IV Acid Rain/CAIR Program
Gavin Plant Units 1 & 2	SO3 Mitigation	4Q - 06	$9,997	NOx SIP Call
Mitchell Unit 1	FGD	2Q - 07	$242,906	Title IV Acid Rain/CAIR Program
Mitchell Unit 1	SCR	2Q - 07	$133,771	NOx SIP Call
Mitchell Unit 1	Balance Draft Conversions	2Q - 07	$24,431	Title IV Acid Rain/CAIR Program
Mitchell Unit 1	Controls Modernization	2Q - 07	$3,026	Title IV Acid Rain/CAIR Program
Mitchell Unit 1	Steam Generator Modifications	2Q - 07	$10,262	Title IV Acid Rain/CAIR Program
Mitchell Unit 1	SO3 Modifications	2Q - 07	$14,827	NOx SIP Call
Mitchell Unit 1	FGD Purge Stream Water Treatment System	2Q - 07	$11,624	Title IV Acid Rain/CAIR Program
Mitchell Unit 1	Coal Blending Station	2Q - 07	$12,280	Title IV Acid Rain/CAIR Program
Mitchell Unit 2	FGD	4Q - 06	$236,154	Title IV Acid Rain Program

EXHIBIT JMM-1

REVISED September 8, 2006

Kentucky Power Company
AEP Pool Surplus Companies
Investment in Environmental Facilities

Generating Unit	Project Description	In-Service Date	New Facilities Cost ($1000s)	Applicable CAA Program
Mitchell Unit 2	SCR	2Q - 07	$137,557	NOx SIP Call
Mitchell Unit 2	Balance Draft Conversions	2Q - 07	$24,431	Title IV Acid Rain/CAIR Program
Mitchell Unit 2	Controls Modernization	2Q - 07	$3,026	Title IV Acid Rain/CAIR Program
Mitchell Unit 2	Steam Generator Modifications	2Q - 07	$10,262	Title IV Acid Rain/CAIR Program
Mitchell Unit 2	SO3 Modifications	2Q - 07	$14,827	NOx SIP Call
Mitchell Unit 2	FGD Purge Stream Water Treatment System	2Q – 07	$11,624	Title IV Acid Rain/CAIR Program
Mitchell Unit 2	Coal Blending Station	2Q - 07	$12,280	Title IV Acid Rain/CAIR Program
Mitchell Units 1 & 2	Impoundment	4Q – 06	$9,644	Title 1 National Ambient Air Quality Standards
Mitchell Units 1 & 2	Gypsum Material Handling	1Q – 07	$33,228	Title IV Acid Rain/CAIR Program
Mitchell Units 1 & 2	Gypsum Material Handling	4Q – 06	$13,123	Title IV Acid Rain/CAIR Program
Mitchell Units 1 & 2	Transformer Rectifier Set Replacement	4Q - 06	$8,351	Title 1 National Ambient Air Quality Standards
Sporn Units 2, 4, & 5	Landfill	4Q - 08	$6,546	Title 1 National Ambient Air Quality Standards
Rockport Units 1 & 2	Landfill	4Q - 08	$998	Title 1 National Ambient Air Quality Standards
Tanners Creek Unit 4	Coal Blending Project	2Q - 06	$90,637	NOx SIP Call and Title IV Acid Rain/CAIR Program
Total Net Investment			$2,030,083	

Kentucky Power Company

REQUEST

Refer to the McManus testimony, pages 19 through 21.

a. Has a federal, state, or local agency established emission limits or emission levels for sulfur trioxides ("SO3")?

b. If yes to part (a), provide the emission limit or emission level, identify the agency establishing the emission limit or emission level, and provide copies of the applicable statute, regulation, or rule.

c. Has a federal, state, or local agency established emission limits or emission levels for sulfuric acid ("H2SO4")?

d. If yes to part (c), provide the emission limit or emission level, identify the agency establishing the emission limit or emission level, and provide copies of the applicable statute, regulation, or rule.

e. Provide the following information for Amos Unit 3, Cardinal Unit 1, Mitchell Unit1, Mitchell Unit 2, and Gavin:

(1) The SO3 emission level immediately prior to the installation of selective catalytic reduction ("SCR") equipment and FGD systems.

(2) The current SO3 emission level at each listed plant.

(3) The anticipated SO3 emission level at each plant after the installation of the SO3 mitigation system.

(4) The H2SO4 emission level immediately prior to the installation of SCR equipment and FGD systems.

(5) The current H2SO4 emission level at each listed plant.

(6) The anticipated H2SO4 emission level at each plant after the installation of the SO3 mitigation system.

f. Quantify what would constitute a "significant" increase in the H2SO4 emission levels that would require additional permits and control equipment under the New Source Review Programs in Title I of the Clean Air Act as amended. Include in the response an explanation of how the "significant" increase is determined.

RESPONSE

a. No such emission limits or emission levels have been established for electric generating units. For additional information, please see the Company's response in 9c below.

b. Not applicable.

c. No such emission limits or emission levels have been established for electric generating units. 40 CFR 52.21(b)(23)(i) defines a "significant" increase in H2SO4 emission levels as 7 tons per year, and 40 CFR 52.21(a)(2) describes the process required to determine whether a significant net increase occurs in connection with a project.

d. Not applicable.

e. Because each of the listed plants has or will have both FGD and SCR systems installed, and SO3 is converted to H2SO4 in the presence of water vapor, we have assumed that upon completion of the projects, all of the SO3 in the flue gases will be converted to H2SO4 prior to exiting the stack. A very small number of tests have been performed to characterize SO3/H2SO4 emission levels at certain of the listed plants under various operating conditions, and more extensive testing was performed at Gavin Plant to determine the relative effectiveness of various SO3 mitigation systems. A summary of ranges of SO3/H2SO4 emission levels available from existing test data of the named plants is provided in the attached Page 3.

For each of the listed plants, the anticipated H2SO4 emission level will be controlled so that no significant net emission increase in SO4/H2SO4 emission levels occurs as a result of the installation of either SCR or FGD control systems at that plant.

f. 40 CFR 52.21(b)(23)(i) defines a "significant" increase in H2SO4 emission levels as 7 tons per year, and 40 CFR 52.21(a)(2) describes the process required to determine whether a significant net increase occurs in connection with a project. A copy of 40 CFR 52.21 has been provided in the attached Pages 4 through 62.

WITNESS: John M McManus

	SO_3/H_2SO_4 prior to installation of SCR/FGD (ppmdv)	SO_3/H_2SO_4 after SCR and FGD installation but without SO_3 mitigation (ppmdv)	SO_3/H_2SO_4 after installation of SO_3/H_2SO_4 mitigation (ppmdv)
Amos Unit 3	N/A	N/A	3.9 to 7 (note 1)
Cardinal Unit 1	N/A	N/A	2.0 to 2.5 (note 2)
Mitchell Unit 1	3.1 to 3.9 (see note 3)	N/A	N/A
Mitchell Unit 2	N/A	N/A	N/A
Gavin Unit 1	N/A	34 to 56 (note 4)	5 to 31 (note 5)
Gavin Unit 2	N/A	18 to 24 (note 6); minimum 29 (note 7)	6.4 to 19 (note 8)

General Notes: Data taken based on actual coal burned. FGD design coal may contain significantly higher sulfur. Variables including fuel sulfur, air heater set points, economizer outlet temperature, etc., can effect SO_3 levels at the stack. Data presented in the table represents stack data. No attempt was made to calculate stack emissions based on SO_3 tests upstream of the stack. Data presented in the table is normalized to 3% O_2.

Note 1: SCR in service, No FGD, SO3 mitigation in service.
Note 2: SCR in service; No FGD; SO3 mitigation in service; some data questionable since ammonia was found in the test probe.
Note 3: No SCR; No FGD; data taken at ESP outlet to stack
Note 4: SCR in service; FGD in service, SO3 mitigation not in service
Note 5: SCR in service; FGD in service, various SO3 mitigation systems in service

Note 6: SCR not in service, FGD in service, SO3 mitigation not in service
Note 7: SCR in service, FGD in service, short period of test data prior to SO3 being place in service.
Note 8: SCR in service, FGD in service, various SO3 mitigation systems in service

40 CFR §52.21 Prevention Of Significant Deterioration Of Air Quality.

(a)(1) *Plan disapproval.* The provisions of this section are applicable to any State implementation plan which has been disapproved with respect to prevention of significant deterioration of air quality in any portion of any State where the existing air quality is better than the national ambient air quality standards. Specific disapprovals are listed where applicable, in subparts B through DDD of this part. The provisions of this section have been incorporated by reference into the applicable implementation plans for various States, as provided in subparts B through DDD of this part. Where this section is so incorporated, the provisions shall also be applicable to all lands owned by the Federal Goverment and Indian Reservations located in such State. No disapproval with respect to a State's failure to prevent significant deterioration of air quality shall invalidate or otherwise affect the obligations of States, emission sources, or other persons with respect to all portions of plans approved or promulgated under this part.

(a)(2) *Applicability procedures.* (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(a)(2)(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

(a)(2)(iii) No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements. The Administrator has authority to issue any such permit.

(a)(2)(iv) The requirements of the program will be applied in accordance with the principles set out in paragraphs (a)(2)(iv)(*a*) through (*f*) of this section.

(a)(2)(iv)(*a*) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases–a significant emissions increase (as defined in paragraph (b)(40) of this section), and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(a)(2)(iv)(*b*) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(*c*) through (*f*) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(a)(2)(iv)(*c*) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(a)(2)(iv)(*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(a)(2)(iv)(*e*) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(a)(2)(iv)(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(*c*) through (*e*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(iv)(*c*) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(*e*) of this section for the Clean Unit.

(a)(2)(v) For any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with the requirements under paragraph (aa) of this section.

(a)(2)(vi) An owner or operator undertaking a PCP (as defined in paragraph (b)(32) of this section) shall comply with the requirements under paragraph (z) of this section.

(b) *Definitions.* For the purposes of this section:

(b)(1)(i) *Major stationary source* means:

(b)(1)(i)(*a*) Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any regulated NSR pollutant: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(b)(1)(i)(*b*) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of a regulated NSR pollutant; or

(b)(1)(i)(*c*) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) of this section, as a major stationary source, if the changes would constitute a major stationary source by itself.

(b)(1)(ii) A major source that is major for volatile organic compounds or NO_X shall be considered major for ozone.

(b)(1)(iii) The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(b)(1)(iii)(*a*) Coal cleaning plants (with thermal dryers);

(b)(1)(iii)(*b*) Kraft pulp mills;

(b)(1)(iii)(*c*) Portland cement plants;

(b)(1)(iii)(*d*) Primary zinc smelters;

(b)(1)(iii)(*e*) Iron and steel mills;

(b)(1)(iii)(*f*) Primary aluminum ore reduction plants;

(b)(1)(iii)(*g*) Primary copper smelters;

(b)(1)(iii)(*h*) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(b)(1)(iii)(*i*) Hydrofluoric, sulfuric, or nitric acid plants;

(b)(1)(iii)(*j*) Petroleum refineries;

(b)(1)(iii)(*k*) Lime plants;

(b)(1)(iii)(*l*) Phosphate rock processing plants;

(b)(1)(iii)(*m*) Coke oven batteries;

(b)(1)(iii)(*n*) Sulfur recovery plants;

(b)(1)(iii)(*o*) Carbon black plants (furnace process);

(b)(1)(iii)(*p*) Primary lead smelters;

(b)(1)(iii)(*q*) Fuel conversion plants;

(b)(1)(iii)(*r*) Sintering plants;

(b)(1)(iii)(*s*) Secondary metal production plants;

(b)(1)(iii)(*t*) Chemical process plants;

(b)(1)(iii)(*u*) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(b)(1)(iii)(*v*) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(b)(1)(iii)(*w*) Taconite ore processing plants;

(b)(1)(iii)(*x*) Glass fiber processing plants;

(b)(1)(iii)(*y*) Charcoal production plants;

(b)(1)(iii)(*z*) Fossil fuel-fired steam electric plants of more that 250 million British thermal units per hour heat input, and

(b)(1)(iii)(*aa*) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(b)(2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(b)(2)(ii) Any significant emissions increase (as defined at paragraph (b)(40) of this section) from any emissions units or net emissions increase (as defined in paragraph (b)(3) of this section) at a major stationary source that is significant for volatile organic compounds or NO_X shall be considered significant for ozone.

(b)(2)(iii) A physical change or change in the method of operation shall not include:

(b)(2)(iii)(*a*) Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (cc) of this section;

Note to paragraph (b)(2)(iii)*(a)*: By court order on December 24, 2003, the second sentence of this paragraph (b)(2)(iii)*(a)* is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

(b)(2)(iii)(*b*) Use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plant pursuant to the Federal Power Act;

(b)(2)(iii)(*c*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(b)(2)(iii)(*d*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(b)(2)(iii)(*e*) Use of an alternative fuel or raw material by a stationary source which:

(b)(2)(iii)(e)(*1*) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166; or

(b)(2)(iii)(e)(2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;

(b)(2)(iii)(*f*) An increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or 40 CFR 51.166.

(b)(2)(iii)(*g*) Any change in ownership at a stationary source.

(b)(2)(iii)(*h*) The addition, replacement, or use of a PCP, as defined in paragraph (b)(32) of this section, at an existing emissions unit meeting the requirements of paragraph (z) of this section. A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion.

(b)(2)(iii)(*i*) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(b)(2)(iii)(*i*)(*1*) The State implementation plan for the State in which the project is located, and

(b)(2)(iii)(*i*)(*2*) Other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(b)(2)(iii)(*j*) The installation or operation of a permanent clean coal technology demonstration project that constitutes repowering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. This exemption shall apply on a pollutant-by-pollutant basis.

(b)(2)(iii)(*k*) The reactivation of a very clean coal-fired electric utility steam generating unit.

(b)(2)(iv) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (aa) of this section for a PAL for that pollutant. Instead, the definition at paragraph (aa)(2)(viii) of this section shall apply.

(b)(3)(i) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(b)(3)(i)(*a*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and

(b)(3)(i)(*b*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(*b*) shall be determined as provided in paragraph (b)(48) of this section, except that paragraphs (b)(48)(i)(*c*) and (b)(48)(ii)(*d*) of this section shall not apply.

(b)(3)(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:

(b)(3)(ii)(*a*) The date five years before construction on the particular change commences; and

(b)(3)(ii)(*b*) The date that the increase from the particular change occurs.

(b)(3)(iii) An increase or decrease in actual emissions is creditable only if:

(b)(3)(iii)(*a*) The Administrator or other reviewing authority has not relied on it in issuing a permit for the source under this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(b)(3)(iii)(*b*) The increase or decrease in emissions did not occur at a Clean Unit except as provided in paragraphs (x)(8) and (y)(10) of this section.

(b)(3)(iv) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

(b)(3)(v) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(b)(3)(vi) A decrease in actual emissions is creditable only to the extent that:

(b)(3)(vi)(*a*) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

(b)(3)(vi)(*b*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins.

(b)(3)(vi)(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(b)(3)(vi)(*d*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under paragraph (y) of this section or under regulations approved pursuant to §51.165(d) or to §51.166(u) of this chapter. That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a "netting analysis" for another emissions unit). However, any new emission reductions that were not relied upon in a PCP excluded pursuant to paragraph (z) of this section or for a Clean Unit designation are creditable to the extent they meet the requirements in paragraph (z)(6)(iv) of this section for the PCP and paragraphs (x)(8) or (y)(10) of this section for a Clean Unit.

(b)(3)(vii) [Reserved]

(b)(3)(viii) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(b)(3)(ix) Paragraph (b)(21)(ii) of this section shall not apply for determining creditable increases and decreases.

(b)(4) *Potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(b)(5) *Stationary source* means any building, structure, facility, or installation which emits or may emit any a regulated NSR pollutant.

(b)(6) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (*i.e.*, which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

(b)(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(b)(7)(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(b)(7)(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

(b)(8) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

(b)(9) *Commence* as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(b)(9)(i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(b)(9)(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(b)(10) *Necessary preconstruction approvals or permits* means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(b)(11) *Begin actual construction* means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying underground pipework and construction of permanent storage structures. With respect to a change in method of operations, this term refers to those on-site activites other than preparatory activities which mark the initiation of the change.

(b)(12) *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the impostion of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

(b)(13)(i) *Baseline concentration* means that ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(b)(13)(i)(*a*) The actual emissions, as defined in paragraph (b)(21) of this section, representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph (b)(13)(ii) of this section; and

(b)(13)(i)(*b*) The allowable emissions of major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(b)(13)(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(b)(13)(ii)(*a*) Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date; and

(b)(13)(ii)(*b*) Actual emissions increases and decreases, as defined in paragraph (b)(21) of this section, at any stationary source occurring after the minor source baseline date.

(b)(14)(i) "Major source baseline date" means:

(b)(14)(i)(*a*) In the case of particulate matter and sulfur dioxide, January 6, 1975, and

(b)(14)(i)(*b*) In the case of nitrogen dioxide, February 8, 1988.

(b)(14)(ii) "Minor source baseline date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to 40 CFR 52.21 or to regulations approved pursuant to 40 CFR 51.166 submits a complete application under the relevant regulations. The trigger date is:

(b)(14)(ii)(*a*) In the case of particulate matter and sulfur dioxide, August 7, 1977, and

(b)(14)(ii)(*b*) In the case of nitrogen dioxide, February 8, 1988.

(b)(14)(iii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(b)(14)(iii)(*a*) The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i)(D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21; and

(b)(14)(iii)(*b*) In the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(b)(14)(iv) Any minor source baseline date established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM-10 increments, except that the Administrator shall rescind a minor source baseline date where it can be shown, to the satisfaction of the Administrator, that the emissions increase from the major stationary source, or net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM-10 emissions.

(b)(15)(i) "Baseline area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under section 107(d)(1)(D) or (E) of the Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than 1 $\mu g/m^3$ (annual average) of the pollutant for which the minor source baseline date is established.

(b)(15)(ii) Area redesignations under section 107(d)(1)(D) or (E) of the Act cannot intersect or be smaller than the area of impact of any mjaor stationary source or major modification which:

(b)(15)(ii)(*a*) Establishes a minor source baseline date; or

(b)(15)(ii)(*b*) Is subject to 40 CFR 52.21 and would be constructed in the same state as the state proposing the redesignation.

(b)(15)(iii) Any baseline area established originally for the TSP increments shall remain in effect and shall apply for purposes of determining the amount of available PM-10 increments, except that such baseline area shall not remain in effect if the Administrator rescinds the corresponding minor source baseline date in accordance with paragraph (b)(14)(iv) of this section.

(b)(16) *Allowable emissions* means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(b)(16)(i) The applicable standards as set forth in 40 CFR parts 60 and 61;

(b)(16)(ii) The applicable State Implemenation Plan emissions limitation, including those with a future compliance date; or

(b)(16)(iii) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(b)(17) *Federally enforceable* means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR part 51, subpart I, including operating permits issued under an EPA-approved program that is incorporated into the State implementation plan and expressly requires adherence to any permit issued under such program.

(b)(18) *Secondary emissions* means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

(b)(18)(i) Emissions from ships or trains coming to or from the new or modified stationary source; and

(b)(18)(ii) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

(b)(19) *Innovative control technology* means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts.

(b)(20) *Fugitive emissions* means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(b)(21)(i) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii) through (iv) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (aa) of this section. Instead, paragraphs (b)(41) and (b)(48) of this section shall apply for those purposes.

(b)(21)(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(b)(21)(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(b)(21)(iv) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(b)(22) *Complete* means, in reference to an application for a permit, that the application contains all of the information necessary for processing the application.

(b)(23)(i) *Significant* means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)

Nitrogen oxides: 40 tpy

Sulfur dioxide: 40 tpy

Particulate matter:

25 tpy of particulate matter emissions;

15 tpy of PM_{10} emissions

Ozone: 40 tpy of volatile organic compounds or NO_X

Lead: 0.6 tpy

Fluorides: 3 tpy

Sulfuric acid mist: 7 tpy

Hydrogen sulfide (H_2S): 10 tpy

Total reduced sulfur (including H_2S): 10 tpy

Reduced sulfur compounds (including H_2S): 10 tpy

Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans): 3.2×10^{-6} megagrams per year (3.5×10^{-6} tons per year). Municipal waste combustor metals (measured as particulate matter): 14 megagrams per year (15 tons per year)

Municipal waste combustor acid gases (measured as sulfur dioxide and hydrogen chloride): 36 megagrams per year (40 tons per year)

Municipal solid waste landfills emissions (measured as nonmethane organic compounds): 45 megagrams per year (50 tons per year)

(b)(23)(ii) *Significant* means, in reference to a net emissions increase or the potential of a source to emit a regulated NSR pollutant that paragraph (b)(23)(i) of this section, does not list, any emissions rate.

(b)(23)(iii) Notwithstanding paragraph (b)(23)(i) of this section, *significant* means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 $\mu g/m^3$, (24-hour average).

(b)(24) *Federal Land Manager* means, with respect to any lands in the United States, the Secretary of the department with authority over such lands.

(b)(25) *High terrain* means any area having an elevation 900 feet or more above the base of the stack of a source.

(b)(26) *Low terrain* means any area other than high terrain.

(b)(27) *Indian Reservation* means any federally recognized reservation established by Treaty, Agreement, executive order, or act of Congress.

(b)(28) *Indian Governing Body* means the governing body of any tribe, band, or group of Indians subject to the jurisdiction of the United States and recognized by the United States as possessing power of self government.

(b)(29) *Adverse impact on visibility* means visibility impairment which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairment, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility.

(b)(30) *Volatile organic compounds (VOC)* is as defined in §51.100(s) of this chapter.

(b)(31) *Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(b)(32) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (b)(39) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (b)(32)(i) through (vi) of this section are presumed to be environmentally beneficial pursuant to paragraph (z)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (z)(2) and (z)(5) of this section.

(b)(32)(i) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(b)(32)(ii) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(b)(32)(iii) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(b)(32)(iv) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, "hydrocarbon combustion flare" means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(b)(32)(v) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(b)(32)(v)(*a*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(b)(32)(v)(*b*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(b)(32)(v)(*c*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of "unclean" wood;

(b)(32)(v)(*d*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(b)(32)(v)(*e*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(b)(32)(vi) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP,) including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (b)(32)(vi)(*a*) and (*b*) of this section.

(b)(32)(vi)(*a*) The productive capacity of the equipment is not increased as a result of the activity or project.

(b)(32)(vi)(*b*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (b)(32)(vi)(*b*)(*1*) through (*4*) of this section.

(b)(32)(vi)(*b*)(*1*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(b)(32)(vi)(*b*)(*2*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(b)(32)(vi)(*b*)(*3*) Calculate the projected ODP-weighted amount by multiplying the projected actual usage of the new substance by its ODP.

(b)(32)(vi)(*b*)(*4*) If the value calculated in paragraph (b)(32)(vi)(*b*)(*2*) of this section is more than the value calculated in paragraph (b)(32)(vi)(*b*)(*3*) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(b)(33) *Replacement unit* means an emissions unit for which all the criteria listed in paragraphs (b)(33)(i) through (iv) of this section are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

(b)(33)(i) The emissions unit is a reconstructed unit within the meaning of §60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.

(b)(33)(ii) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

(b)(33)(iii) The replacement does not alter the basic design parameters (as discussed in paragraph (cc)(2) of this section) of the process unit.

(b)(33)(iv) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

(b)(34) *Clean coal technology* means any technology, including technologies applied at the precombustion, combustion, or post combustion stage, at a new or existing facility which will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990.

(b)(35) *Clean coal technology demonstration project* means a project using funds appropriated under the heading "Department of Energy-Clean Coal Technology", up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency. The Federal contribution for a qualifying project shall be at least 20 percent of the total cost of the demonstration project.

(b)(36) *Temporary clean coal technology demonstration project* means a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plans for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(b)(37)(i) *Repowering* means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990.

(b)(37)(ii) Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

(b)(37)(iii) The Administrator shall give expedited consideration to permit applications for any source that satisfies the requirements of this subsection and is granted an extension under section 409 of the Clean Air Act.

(b)(38) *Reactivation of a very clean coal-fired electric utility steam generating unit* means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(b)(38)(i) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(b)(38)(ii) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(b)(38)(iii) Is equipped with low-NO_x burners prior to the time of commencement of operations following reactivation; and

(b)(38)(iv) Is otherwise in compliance with the requirements of the Clean Air Act.

(b)(39) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain "in-process recycling" practices), energy recovery, treatment, or disposal.

(b)(40) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

(b)(41)(i) *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(b)(41)(ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(b)(41)(ii)(*a*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and

(b)(41)(ii)(*b*) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(b)(41)(ii)(*c*) Shall exclude, in calculating any increase in emissions that results from he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or

(b)(41)(ii)(*d*) In lieu of using the method set out in paragraphs (a)(41)(ii)(*a*) through (*c*) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(b)(42) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to paragraph (x) of this section; or any emissions unit that has been designated by the Administrator as a Clean Unit, based on the criteria in paragraphs (y)(3)(i) through (iv) of this section; or any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved into the State Implementation Plan in accordance with §51.165(c) or §51.166(u) of this chapter; or any emissions unit that has been designated by the reviewing authority as a Clean Unit in accordance with regulations approved into the plan to carry out §51.165(d) or §51.166(u) of this chapter.

(b)(43) *Prevention of Significant Deterioration (PSD) program* means the EPA-implemented major source preconstruction permit programs under this section or a major source preconstruction permit program that has been approved by the Administrator and incorporated into the State Implementation Plan pursuant to §51.166 of this chapter to implement the requirements of that section. Any permit issued under such a program is a major NSR permit.

(b)(44) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(b)(45) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(b)(46) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(b)(47) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(b)(48) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.

(b)(48)(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(b)(48)(i)(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(b)(48)(i)(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

(b)(48)(i)(*c*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(b)(48)(i)(*d*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(48)(i)(*b*) of this section.

(b)(48)(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(b)(48)(ii)(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(b)(48)(ii)(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(b)(48)(ii)(*c*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of §51.165(a)(3)(ii)(G) of this chapter.

(b)(48)(ii)(*d*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(b)(48)(ii)(*e*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(48)(ii)(*b*) and (*c*) of this section.

(b)(48)(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(b)(48)(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(48)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(48)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(48)(iii) of this section.

(b)(49) [Reserved]

(b)(50) *Regulated NSR pollutant*, for purposes of this section, means the following:

(b)(50)(i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and NO_X are precursors for ozone);

(b)(50)(ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;

(b)(50)(iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(b)(50)(iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

(b)(51) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under §51.165 and §51.166 of this chapter, or the Administrator in the case of EPA-implemented permit programs under this section.

(b)(52) *Project* means a physical change in, or change in the method of operation of, an existing major stationary source.

(b)(53) *Lowest achievable emission rate (LAER)* is as defined in §51.165(a)(1)(xiii) of this chapter.

(b)(54) *Reasonably available control technology (RACT)* is as defined in §51.100(o) of this chapter.

(b)(55)(i) In general, *process unit* means any collection of structures and/or equipment that processes, assembles, applies, blends, or otherwise uses material inputs to produce or store an intermediate or a completed product. A single stationary source may contain more than one process unit, and a process unit may contain more than one emissions unit.

(b)(55)(ii) Pollution control equipment is not part of the process unit, unless it serves a dual function as both process and control equipment. Administrative and warehousing facilities are not part of the process unit.

(b)(55)(iii) For replacement cost purposes, components shared between two or more process units are proportionately allocated based on capacity.

(b)(55)(iv) The following list identifies the process units at specific categories of stationary sources.

(b)(55)(iv)(*a*) For a steam electric generating facility, the process unit consists of those portions of the plant that contribute directly to the production of electricity. For example, at a pulverized coal-fired facility, the process unit would generally be the combination of those systems from the coal receiving equipment through the emission stack (excluding post-combustion pollution controls), including the coal handling equipment, pulverizers or coal crushers, feedwater heaters, ash handling, boiler, burners, turbine-generator set, condenser, cooling tower, water treatment system, air preheaters, and operating control systems. Each separate generating unit is a separate process unit.

(b)(55)(iv)(*b*) For a petroleum refinery, there are several categories of process units: those that separate and/or distill petroleum feedstocks; those that change molecular structures; petroleum treating processes; auxiliary facilities, such as steam generators and hydrogen production units; and those that load, unload, blend or store intermediate or completed products.

(b)(55)(iv)(*c*) For an incinerator, the process unit would consist of components from the feed pit or refuse pit to the stack, including conveyors, combustion devices, heat exchangers and steam generators, quench tanks, and fans.

Note to paragraph (b)(55): By a court order on December 24, 2003, this paragraph (b)(55) is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

(b)(56) *Functionally equivalent component* means a component that serves the same purpose as the replaced component.

Note to paragraph (b)(56): By a court order on December 24, 2003, this paragraph (b)(56) is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

(b)(57) *Fixed capital cost* means the capital needed to provide all the depreciable components. "Depreciable components" refers to all components of fixed capital cost and is calculated by subtracting land and working capital from the total capital investment, as defined in paragraph (b)(58) of this section.

Note to paragraph (b)(57): By a court order on December 24, 2003, this paragraph (b)(57) is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

(b)(58) *Total capital investment* means the sum of the following: all costs required to purchase needed process equipment (purchased equipment costs); the costs of labor and materials for installing that equipment (direct installation costs); the costs of site preparation and buildings; other costs such as engineering, construction and field expenses, fees to contractors, startup and performance tests, and contingencies (indirect installation costs); land for the process equipment; and working capital for the process equipment.

Note to paragraph (b)(58): By a court order on December 24, 2003, this paragraph (b)(58) is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

(*c*) *Ambient air increments.* In areas designated as Class I, II or III, increases in pollutant concentration over the baseline concentration shall be limited to the following:

Pollutant	Maximum allowable increase (micrograms per cubic meter)
CLASS I	
Particulate matter:	
PM-10, annual arithmetic mean	4
PM-10, 24-hr maximum	8
Sulfur dioxide:	
Annual arithmetic mean	2
24-hr maximum	5
3-hr maximum	25
Nitrogen dioxide:	
Annual arithmetic mean	2.5
CLASS II	
Particulate matter:	
PM-10, annual arithmetic mean	17
PM-10, 24-hr maximum	30
Sulfur dioxide:	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	512
Nitrogen dioxide:	
Annual arithmetic mean	25
CLASS III	
Particulate matter:	
PM-10, annual arithmetic mean	34
PM-10, 24-hr maximum	60
Sulfur dioxide:	
Annual arithmetic mean	40
24-hr maximum	182
3-hr maximum	700
Nitrogen dioxide:	
Annual arithmetic mean	50

For any period other than an annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

(d) *Ambient air ceilings.* No concentration of a pollutant shall exceed:

(d)(1) The concentration permitted under the national secondary ambient air quality standard, or

(d)(2) The concentration permitted under the national primary ambient air quality standard, whichever concentration is lowest for the pollutant for a period of exposure.

(e) *Restrictions on area classifications.* (1) All of the following areas which were in existence on August 7, 1977, shall be Class I areas and may not be redesignated:

(e)(1)(i) International parks,

(e)(1)(ii) National wilderness areas which exceed 5,000 acres in size,

(e)(1)(iii) National memorial parks which exceed 5,000 acres in size, and

(e)(1)(iv) National parks which exceed 6,000 acres in size.

(e)(2) Areas which were redesignated as Class I under regulations promulgated before August 7, 1977, shall remain Class I, but may be redesignated as provided in this section.

(e)(3) Any other area, unless otherwise specified in the legislation creating such an area, is initially designated Class II, but may be redesignated as provided in this section.

(e)(4) The following areas may be redesignated only as Class I or II:

(e)(4)(i) An area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreational area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

(e)(4)(ii) A national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

(f) [Reserved]

(g) *Redesignation.* (1) All areas (except as otherwise provided under paragraph (e) of this section) are designated Class II as of December 5, 1974. Redesignation (except as otherwise precluded by paragraph (e) of this section) may be proposed by the respective States or Indian Governing Bodies, as provided below, subject to approval by the Administrator as a revision to the applicable State implementation plan.

(g)(2) The State may submit to the Administrator a proposal to redesignate areas of the State Class I or Class II provided that:

(g)(2)(i) At least one public hearing has been held in accordance with procedures established in §51.102 of this chapter;

(g)(2)(ii) Other States, Indian Governing Bodies, and Federal Land Managers whose lands may be affected by the proposed redesignation were notified at least 30 days prior to the public hearing;

(g)(2)(iii) A discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic, social and energy effects of the proposed redesignation, was prepared and made available for public inspection at least 30 days prior to the hearing and the notice announcing the hearing contained appropriate notification of the availability of such discussion;

(g)(2)(iv) Prior to the issuance of notice respecting the redesignation of an area that includes any Federal lands, the State has provided written notice to the appropriate Federal Land Manager and afforded adequate opportunity (not in excess of 60 days) to confer with the State respecting the redesignation and to submit written comments and recommendations. In redesignating any area with respect to which any Federal Land Manager had submitted written comments and recommendations, the State shall have published a list of any inconsistency between such redesignation and such comments and recommendations (together with the reasons for making such redesignation against the recommendation of the Federal Land Manager); and

(g)(2)(v) The State has proposed the redesignation after consultation with the elected leadership of local and other substate general purpose governments in the area covered by the proposed redesignation.

(g)(3) Any area other than an area to which paragraph (e) of this section refers may be redesignated as Class III if--

(g)(3)(i) The redesignation would meet the requirements of paragraph (g)(2) of this section;

(g)(3)(ii) The redesignation, except any established by an Indian Governing Body, has been specifically approved by the Governor of the State, after consultation with the appropriate committees of the legislature, if it is in session, or with the leadership of the legislature, if it is not in session (unless State law provides that the redesignation must be specifically approved by State legislation) and if general purpose units of local government representing a majority of the residents of the area to be redesignated enact legislation or pass resolutions concurring in the redesignation:

(g)(3)(iii) The redesignation would not cause, or contribute to, a concentration of any air pollutant which would exceed any maximum allowable increase permitted under the classification of any other area or any national ambient air quality standard; and

(g)(3)(iv) Any permit application for any major stationary source or major modification, subject to review under paragraph (l) of this section, which could receive a permit under this section only if the area in question were redesignated as Class III, and any material submitted as part of that application, were available insofar as was practicable for public inspection prior to any public hearing on redesignation of the area as Class III.

(g)(4) Lands within the exterior boundaries of Indian Reservations may be redesignated only by the appropriate Indian Governing Body. The appropriate Indian Governing Body may submit to the Administrator a proposal to redesignate areas Class I, Class II, or Class III: *Provided,* That:

(g)(4)(i) The Indian Governing Body has followed procedures equivalent to those required of a State under paragraphs (g)(2), (g)(3)(iii), and (g)(3)(iv) of this section; and

(g)(4)(ii) Such redesignation is proposed after consultation with the State(s) in which the Indian Reservation is located and which border the Indian Reservation.

(g)(5) The Administrator shall disapprove, within 90 days of submission, a proposed redesignation of any area only if he finds, after notice and opportunity for public hearing, that such redesignation does not meet the procedural requirements of this paragraph or is inconsistent with paragraph (e) of this section. If any such disapproval occurs, the classification of the area shall be that which was in effect prior to the redesignation which was disapproved.

(g)(6) If the Administrator disapproves any proposed redesignation, the State or Indian Governing Body, as appropriate, may resubmit the proposal after correcting the deficiencies noted by the Administrator.

(h) *Stack heights.* (1) The degree of emission limitation required for control of any air pollutant under this section shall not be affected in any manner by--

(h)(1)(i) So much of the stack height of any source as exceeds good engineering practice, or

(h)(1)(ii) Any other dispersion technique.

(h)(2) Paragraph (h)(1) of this section shall not apply with respect to stack heights in existence before December 31, 1970, or to dispersion techniques implemented before then.

(i) *Exemptions.* (1) The requirements of paragraphs (j) through (r) of this section shall not apply to a particular major stationary source or major modification, if;

(i)(1)(i) Construction commenced on the source or modification before August 7, 1977. The regulations at 40 CFR 52.21 as in effect before August 7, 1977, shall govern the review and permitting of any such source or modification; or

(i)(1)(ii) The source or modification was subject to the review requirements of 40 CFR 52.21(d)(1) as in effect before March 1, 1978, and the owner or operator:

(i)(1)(ii)(*a*) Obtained under 40 CFR 52.21 a final approval effective before March 1, 1978;

(i)(1)(ii)(*b*) Commenced construction before March 19, 1979; and

(i)(1)(ii)(*c*) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time; or

(i)(1)(iii) The source or modification was subject to 40 CFR 52.21 as in effect before March 1, 1978, and the review of an application for approval for the stationary source or modification under 40 CFR 52.21 would have been completed by March 1, 1978, but for an extension of the public comment period pursuant to a request for such an extension. In such a case, the application shall continue to be processed, and granted or denied, under 40 CFR 52.21 as in effect prior to March 1, 1978; or

(i)(1)(iv) The source or modification was not subject to 40 CFR 52.21 as in effect before March 1, 1978, and the owner or operator:

(i)(1)(iv)(*a*) Obtained all final Federal, state and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before March 1, 1978;

(i)(1)(iv)(*b*) Commenced construction before March 19, 1979; and

(i)(1)(iv)(*c*) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time; or

(i)(1)(v) The source or modification was not subject to 40 CFR 52.21 as in effect on June 19, 1978 or under the partial stay of regulations published on February 5, 1980 (45 FR 7800), and the owner or operator:

(i)(1)(v)(*a*) Obtained all final Federal, state and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before August 7, 1980;

(i)(1)(v)(*b*) Commenced construction within 18 months from August 7, 1980, or any earlier time required under the applicable State Implementation Plan; and

(i)(1)(v)(*c*) Did not discontinuue construction for a period of 18 months or more and completed construction within a reasonable time; or

(i)(1)(vi) The source or modification would be a nonprofit health or nonprofit educational institution, or a major modification would occur at such an institution, and the governor of the state in which the source or modification would be located requests that it be exempt from those requirements;

or

(i)(1)(vii) The source or modification would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(i)(1)(vii)(*a*) Coal cleaning plants (with thermal dryers);

(i)(1)(vii)(*b*) Kraft pulp mills;

(i)(1)(vii)(*c*) Portland cement plants;

(i)(1)(vii)(*d*) Primary zinc smelters;

(i)(1)(vii)(*e*) Iron and steel mills;

(i)(1)(vii)(*f*) Primary aluminum ore reduction plants;

(i)(1)(vii)(*g*) Primary copper smelters;

(i)(1)(vii)(*h*) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(i)(1)(vii)(*i*) Hydrofluoric, sulfuric, or nitric acid plants;

(i)(1)(vii)(*j*) Petroleum refineries;

(i)(1)(vii)(*k*) Lime plants;

(i)(1)(vii)(*l*) Phosphate rock processing plants;

(i)(1)(vii)(*m*) Coke oven batteries;

(i)(1)(vii)(*n*) Sulfur recovery plants;

(i)(1)(vii)(*o*) Carbon black plants (furnace process);

(i)(1)(vii)(*p*) Primary lead smelters;

(i)(1)(vii)(*q*) Fuel conversion plants;

(i)(1)(vii)(*r*) Sintering plants;

(i)(1)(vii)(*s*) Secondary metal production plants;

(i)(1)(vii)(*t*) Chemical process plants;

(i)(1)(vii)(*u*) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(i)(1)(vii)(*v*) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(i)(1)(vii)(*w*) Taconite ore processing plants;

(i)(1)(vii)(*x*) Glass fiber processing plants;

(i)(1)(vii)(*y*) Charcoal production plants;

(i)(1)(vii)(*z*) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(i)(1)(vii)(*aa*) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act; or

(i)(1)(viii) The source is a portable stationary source which has previously received a permit under this section, and

(i)(1)(viii)(*a*) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(i)(1)(viii)(*b*) The emissions from the source would not exceed its allowable emissions; and

(i)(1)(viii)(*c*) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated; and

(i)(1)(viii)(*d*) Reasonable notice is given to the Administrator prior to the relocation identifying the proposed new location and the probable duration of operation at the new location. Such notice shall be given to the Administrator not less than 10 days in advance of the proposed relocation unless a different time duration is previously approved by the Administrator.

(i)(1)(ix) The source or modification was not subject to §52.21 with respect to particulate matter, as in effect before July 31, 1987, and the owner or operator:

(i)(1)(ix)(*a*) Obtained all final Federal, State, and local preconstruction approvals or permits necessary under the applicable State implementation plan before July 31, 1987;

(i)(1)(ix)(*b*) Commenced construction within 18 months after July 31, 1987, or any earlier time required under the State implementation plan; and

(i)(1)(ix)(*c*) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable period of time.

(i)(1)(x) The source or modification was subject to 40 CFR 52.21, with respect to particulate matter, as in effect before July 31, 1987 and the owner or operator submitted an application for a permit under this section before that date, and the Administrator subsequently determines that the application as submitted was complete with respect to the particulate matter requirements then in effect in this section. Instead, the requirements of paragraphs (j) through (r) of this section that were in effect before July 31, 1987 shall apply to such source or modification.

(i)(2) The requirements of paragraphs (j) through (r) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment under section 107 of the Act.

(i)(3) The requirements of paragraphs (k), (m) and (o) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant, if the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i)(3)(i) Would impact no Class I area and no area where an applicable increment is known to be violated, and

(i)(3)(ii) Would be temporary.

(i)(4) The requirements of paragraphs (k), (m) and (o) of this section as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a stationary source that was in existence on March 1, 1978, if the net increase in allowable emissions of each regulated NSR pollutant from the modification after the application of best available control technology would be less than 50 tons per year.

(i)(5) The Administrator may exempt a stationary source or modification from the requirements of paragraph (m) of this section, with respect to monitoring for a particular pollutant if:

(i)(5)(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide--575 μg/m^3, 8-hour average;

Nitrogen dioxide--14 μg/m^3, annual average;

Particulate matter--10 μg/m^3 of PM-10, 24-hour average;

Sulfur dioxide--13 μg/m^3, 24-hour average;

Ozone;[1]

1 No *de minimis* air quality level is provided for ozone. However, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data.

Lead--0.1 μg/m^3, 3-month average;

Fluorides--0.25 μg/m^3, 24-hour average;

Total reduced sulfur--10 μg/m^3, 1-hour average;

Hydrogen sulfide--0.2 μg/m^3, 1-hour average;

Reduced sulfur compounds--10 μg/m^3, 1-hour average; or

(i)(5)(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in paragraph (i)(8)(i) of this section, or the pollutant is not listed in paragraph (i)(8)(i) of this section.

(i)(6) The requirements for best available control technology in paragraph (j) of this section and the requirements for air quality analyses in paragraph (m)(1) of this section, shall not apply to a particular stationary source or modification that was subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submitted an application for a permit under those regulations before August 7, 1980, and the Administrator subsequently determines that the application as submitted before that date was complete. Instead, the requirements at 40 CFR 52.21(i) and (n) as in effect on June 19, 1978 apply to any such source or modification.

(i)(7)(i) The requirements for air quality monitoring in paragraphs (m)(1)(ii) through (iv) of this section shall not apply to a particular source or modification that was subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submits an application for a permit under this section on or before June 8, 1981, and the Administrator subsequently determines that the application as submitted before that date was complete with respect to the requirements of this section other than those in paragraphs (m)(1)(ii) through (iv) of this section, and with respect to the requirements for such analyses at 40 CFR 52.21(m)(2) as in effect on June 19, 1978. Instead, the latter requirements shall apply to any such source or modification.

(i)(7)(ii) The requirements for air quality monitoring in paragraphs (m)(1)(ii) through (iv) of this section shall not apply to a particular source or modification that was not subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submits an application for a permit under this section on or before June 8, 1981, and the Administrator subsequently determines that the application as submitted before that date was complete, except with respect to the requirements in paragraphs (m)(1)(ii) through (iv).

(i)(8)(i) At the discretion of the Administrator, the requirements for air quality monitoring of PM_{10} in paragraphs (m)(1)(i)–(iv) of this section may not apply to a particular source or modification when the owner or operator of the source or modification submits an application for a permit under this section on or before June 1, 1988 and the Administrator subsequently determines that the application as submitted before that date was complete, except with respect to the requirements for monitoring particulate matter in paragraphs (m)(1)(i)–(iv).

(i)(8)(ii) The requirements for air quiality monitoring pf PM_{10} in paragraphs (m)(1), (ii) and (iv) and (m)(3) of this section shall apply to a particular source or modification if the owner or operator of the source or modification submits an application for a permit under this section after June 1, 1988 and no later than December 1, 1988. The data shall have been gathered over at least the period from February 1, 1988 to the date the application becomes otherwise complete in accordance with the provisions set forth under paragraph (m)(1)(viii) of this section, except that if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data over a shorter period (not to be less than 4 months), the data that paragraph (m)(1)(iii) requires shall have been gathered over a shorter period.

(i)(9) The requirements of paragraph (k)(2) of this section shall not apply to a stationary source or modification with respect to any maximum allowable increase for nitrogen oxides if the owner or operator of the source or modification submitted an application for a permit under this section before the provisions embodying the maximum allowable increase took effect as part of the applicable implementation plan and the Administrator subsequently determined that the application as submitted before that date was complete.

(i)(10) The requirements in paragraph (k)(2) of this section shall not apply to a stationary source or modification with respect to any maximum allowable increase for PM-10 if (i) the owner or operator of the source or modification submitted an application for a permit under this section before the provisions embodying the maximum allowable increases for PM-10 took effect in an implementation plan to which this section applies, and (ii) the Administrator subsequently determined that the application as submitted before that date was otherwise complete. Instead, the requirements in paragraph (k)(2) shall apply with respect to the maximum allowable increases for TSP as in effect on the date the application was submitted.

(j) *Control technology review.* (1) A major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61.

(j)(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

(j)(3) A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.

(j)(4) For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

(k) *Source impact analysis.* The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:

(k)(1) Any national ambient air quality standard in any air quality control region; or

(k)(2) Any applicable maximum allowable increase over the baseline concentration in any area.

(l) *Air quality models.* (1) All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).

(l)(2) Where an air quality model specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models) is inappropriate, the model may be modified or another model substituted. Such a modification or substitution of a model may be made on a case-by-case basis or, where appropriate, on a generic basis for a specific state program. Written approval of the Administrator must be obtained for any modification or substitution. In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment under procedures developed in accordance with paragraph (q) of this section.

(m) *Air quality analysis*--(1) *Preapplication analysis.* (i) Any application for a permit under this section shall contain an analysis of ambient air quality in the area that the major stationary source or major modification would affect for each of the following pollutants:

(m)(1)(i)(*a*) For the source, each pollutant that it would have the potential to omit in a significant amount;

(m)(1)(i)(*b*) For the modification, each pollutant for which it would result in a significant net emissions increase.

(m)(1)(ii) With respect to any such pollutant for which no National Ambient Air Quality Standard exists, the analysis shall contain such air quality monitoring data as the Administrator determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect.

(m)(1)(iii) With respect to any such pollutant (other than nonmethane hydrocarbons) for which such a standard does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase.

(m)(1)(iv) In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the application, except that, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period.

(m)(1)(v) For any application which becomes complete, except as to the requirements of paragraphs (m)(1)(iii) and (iv) of this section, between June 8, 1981, and February 9, 1982, the data that paragraph (m)(1)(iii) of this section, requires shall have been gathered over at least the period from February 9, 1981, to the date the application becomes otherwise complete, except that:

(m)(1)(v)(*a*) If the source or modification would have been major for that pollutant under 40 CFR 52.21 as in effect on June 19, 1978, any monitoring data shall have been gathered over at least the period required by those regulations.

(m)(1)(v)(*b*) If the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data over a shorter period (not to be less than four months), the data that paragraph (m)(1)(iii) of this section, requires shall have been gathered over at least that shorter period.

(m)(1)(v)(*c*) If the monitoring data would relate exclusively to ozone and would not have been required under 40 CFR 52.21 as in effect on June 19, 1978, the Administrator may waive the otherwise applicable requirements of this paragraph (v) to the extent that the applicant shows that the monitoring data would be unrepresentative of air quality over a full year.

(m)(1)(vi) The owner or operator of a proposed stationary source or modification of violatile organic compounds who satisfies all conditions of 40 CFR part 51 Appendix S, section IV may provide post-approval monitoring data for ozone in lieu of providing preconstruction data as requried under paragraph (m)(1) of this section.

(m)(1)(vii) For any application that becomes complete, except as to the requirements of paragraphs (m)(1)(iii) and (iv) pertaining to PM_{10}, after December 1, 1988 and no later than August 1, 1989 the data that paragraph (m)(1)(iii) requires shall have been gathered over at least the period from August 1, 1988 to the date the application becomes otherwise complete, except that if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data over a shorter period (not to be less than 4 months), the data that paragraph (m)(1)(iii) requires shall have been gathered over that shorter period.

(m)(1)(viii) With respect to any requirements for air quality monitoring of PM_{10} under paragraphs (i)(11)(i) and (ii) of this sectionm the owner or operator of the source or modification shall use a monitoring method approved by the Administrator and shall estimate the ambient concentrations of PM_{10} using the data collected by such approved monitoring method in accordance with estimating procedures approved by the Administrator.

(m)(2) Post-construction monitoring. The owner or operator of a major stationary source or major modification shall, after construction of the stationary source or modification, conduct such ambient monitoring as the Administrator determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having, on air quality in any area.

(m)(3) Operations of monitoring stations. The owner or operator of a major stationary source or major modification shall meet the requirements of Appendix B to part 58 of this chapter during the operation of monitoring stations for purposes of satisfying paragraph (m) of this section.

(n) *Source information.* The owner or operator of a proposed source or modification shall submit all information necessary to perform any analysis or make any determination required under this section.

(n)(1) With respect to a source or modification to which paragraphs (j), (l), (n) and (p) of this section apply, such information shall include:

(n)(1)(i) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design and plant layout;

(n)(1)(ii) A detailed schedule for construction of the source or modification;

(n)(1)(iii) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine that best available control technology would be applied.

(n)(2) Upon request of the Administrator, the owner or operator shall also provide information on:

(n)(2)(i) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and

(n)(2)(ii) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

(o) *Additional impact analyses.* (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(o)(2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

(o)(3) *Visibility monitoring.* The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate.

(p) *Sources impacting Federal Class I areas--additional requirements--*(1) *Notice to Federal land managers.* The Administrator shall provide written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the Federal land manager and the Federal official charged with direct responsibility for management of any lands within any such area. Such notification shall include a copy of all information relevant to the permit application and shall be given within 30 days of receipt and at least 60 days prior to any public hearing on the application for a permit to construct. Such notification shall include an analysis of the proposed source's anticipated impacts on visibility in the Federal Class I area. The Administrator shall also provide the Federal land manager and such Federal officials with a copy of the preliminary determination required under paragraph (q) of this section, and shall make available to them any materials used in making that determination, promptly after the Administrator makes such determination. Finally, the Administrator shall also notify all affected Federal land managers within 30 days of receipt of any advance notification of any such permit application.

(p)(2) *Federal Land Manager.* The Federal Land Manager and the Federal official charged with direct responsibility for management of such lands have an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider, in consultation with the Administrator, whether a proposed source or modification will have an adverse impact on such values.

(p)(3) *Visibility analysis.* The Administrator shall consider any analysis performed by the Federal land manager, provided within 30 days of the notification required by paragraph (p)(1) of this section, that shows that a proposed new major stationary source or major modification may have an adverse impact on visibility in any Federal Class I area. Where the Administrator finds that such an analysis does not demonstrate to the satisfaction of the Administrator that an adverse impact on visibility will result in the Federal Class I area, the Administrator must, in the notice of public hearing on the permit application, either explain his decision or give notice as to where the explanation can be obtained.

(p)(4) *Denial--impact on air quality related values.* The Federal Land Manager of any such lands may demonstrate to the Administrator that the emissions from a proposed source or modification would have an adverse impact on the air quality-related values (including visibility) of those lands, notwithstanding that the change in air quality resulting from emissions from such source or modification would not cause or contribute to concentrations which would exceed the maximum allowable increases for a Class I area. If the Administrator concurs with such demonstration, then he shall not issue the permit.

(p)(5) *Class I variances.* The owner or operator of a proposed source or modification may demonstrate to the Federal Land Manager that the emissions from such source or modification would have no adverse impact on the air quality related values of any such lands (including visibility), notwithstanding that the change in air quality resulting from emissions from such source or modification would cause or contribute to concentrations which would exceed the maximum allowable increases for a Class I area. If the Federal Land Manager concurs with such demonstration and he so certifies, the State may authorize the Administrator: *Provided,* That the applicable requirements of this section are otherwise met, to issue the permit with such emission limitations as may be necessary to assure that emissions of sulfur dioxide and particulate matter, and nitrogen oxides would not exceed the followng maximum allowable increases over minor source baseline concentration for such pollutants:

Pollutant	Maximum allowable increase (micrograms per cubic meter)
Particulate matter:	
PM-10, annual arithmetic mean	17
PM-10, 24-hr maximum	30
Sulfur dioxide:	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	325
Nitrogen dioxide:	
Annual arithmetic mean	25

(p)(6) *Sulfur dioxide variance by Governor with Federal Land Manager's concurrence.* The owner or operator of a proposed source or modification which cannot be approved under paragraph (q)(4) of this section may demonstrate to the Governor that the source cannot be constructed by reason of any maximum allowable increase for sulfur dioxide for a period of twenty-four hours or less applicable to any Class I area and, in the case of Federal mandatory Class I areas, that a variance under this clause would not adversely affect the air quality related values of the area (including visibility). The Governor, after consideration of the Federal Land Manager's recommendation (if any) and subject to his concurrence, may, after notice and public hearing, grant a variance from such maximum allowable increase. If such variance is granted, the Administrator shall issue a permit to such source or modification pursuant to the requirements of paragraph (q)(7) of this section: *Provided,* That the applicable requirements of this section are otherwise met.

(p)(7) *Variance by the Governor with the President's concurrence.* In any case where the Governor recommends a variance in which the Federal Land Manager does not concur, the recommendations of the Governor and the Federal Land Manager shall be transmitted to the President. The President may approve the Governor's recommendation if he finds that the variance is in the national interest. If the variance is approved, the Administrator shall issue a permit pursuant to the requirements of paragraph (q)(7) of this section: *Provided,* That the applicable requirements of this section are otherwise met.

(p)(8) *Emission limitations for Presidential or gubernatorial variance.* In the case of a permit issued pursuant to paragraph (q)(5) or (6) of this section the source or modification shall comply with such emission limitations as may be necessary to assure that emissions of sulfur dioxide from the source or modification would not (during any day on which the otherwise applicable maximum allowable increases are exceeded) cause or contribute to concentrations which would exceed the following maximum allowable increases over the baseline concentration and to assure that such emissions would not cause or contribute to concentrations which exceed the otherwise applicable maximum allowable increases for periods of exposure of 24 hours or less for more than 18 days, not necessarily consecutive, during any annual period:

MAXIMUM ALLOWABLE INCREASE
[Micrograms per cubic meter]

Period of exposure	Terrain areas	
	Low	High
24-hr maximum	36	62
3-hr maximum	130	221

(q) *Public participation.* The Administrator shall follow the applicable procedures of 40 CFR part 124 in processing applications under this section. The Administrator shall follow the procedures at 40 CFR 52.21(r) as in effect on June 19, 1979, to the extent that the procedures of 40 CFR part 124 do not apply.

(r) *Source obligation.* (1) Any owner or operator who constructs or operates a source or modification not in accordance with the application submitted pursuant to this section or with the terms of any approval to construct, or any owner or operator of a source or modification subject to this section who commences construction after the effective date of these regulations without applying for and receiving approval hereunder, shall be subject to appropriate enforcement action.

(r)(2) Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

(r)(3) Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the State implementation plan and any other requirements under local, State, or Federal law.

(r)(4) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements or paragraphs (j) through (s) of this section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(r)(5) [Reserved]

(r)(6) The provisions of this paragraph (r)(6) apply to projects at an existing emissions unit at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(*a*) through (*c*) of this section for calculating projected actual emissions.

(r)(6)(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(r)(6)(i)(*a*) A description of the project;

(r)(6)(i)(*b*) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(r)(6)(i)(*c*) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(41)(ii)(*c*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(r)(6)(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i) of this section to the Administrator. Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction.

(r)(6)(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(*b*) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated NSR pollutant at such emissions unit.

(r)(6)(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Administrator within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(r)(6)(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Administrator if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section), by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section. Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

(r)(6)(v)(*a*) The name, address and telephone number of the major stationary source;

(r)(6)(v)(*b*) The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

(r)(6)(v)(*c*) Any other information that the owner or operator wishes to include in the report (*e.g.*, an explanation as to why the emissions differ from the preconstruction projection).

(r)(7) The owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon a request for inspection by the Administrator or the general public pursuant to the requirements contained in §70.4(b)(3)(viii) of this chapter.

(s) *Environmental impact statements.* Whenever any proposed source or modification is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act (42 U.S.C. 4321), review by the Administrator conducted pursuant to this section shall be coordinated with the broad environmental reviews under that Act and under section 309 of the Clean Air Act to the maximum extent feasible and reasonable.

(t) *Disputed permits or redesignations.* If any State affected by the redesignation of an area by an Indian Governing Body, or any Indian Governing Body of a tribe affected by the redesignation of an area by a State, disagrees with such redesignation, or if a permit is proposed to be issued for any major stationary source or major modification proposed for construction in any State which the Governor of an affected State or Indian Governing Body of an affected tribe determines will cause or contribute to a cumulative change in air quality in excess of that allowed in this part within the affected State or Indian Reservation, the Governor or Indian Governing Body may request the Administrator to enter into negotiations with the parties involved to resolve such dispute. If requested by any State or Indian Governing Body involved, the Administrator shall make a recommendation to resolve the dispute and protect the air quality related values of the lands involved. If the parties involved do not reach agreement, the Administrator shall resolve the dispute and his determination, or the results of agreements reached through other means, shall become part of the applicable State implementation plan and shall be enforceable as part of such plan. In resolving such disputes relating to area redesignation, the Administrator shall consider the extent to which the lands involved are of sufficient size to allow effective air quality management or have air quality related values of such an area.

(u) *Delegation of authority.* (1) The Administrator shall have the authority to delegate his responsibility for conducting source review pursuant to this section, in accordance with paragraphs (v)(2) and (3) of this section.

(u)(2) Where the Administrator delegates the responsibility for conducting source review under this section to any agency other than a Regional Office of the Environmental Protection Agency, the following provisions shall apply:

(u)(2)(i) Where the delegate agency is not an air pollution control agency, it shall consult with the appropriate State and local air pollution control agency prior to making any determination under this section. Similarly, where the delegate agency does not have continuing responsibility for managing land use, it shall consult with the appropriate State and local agency primarily responsible for managing land use prior to making any determination under this section.

(u)(2)(ii) The delegate agency shall send a copy of any public comment notice required under paragraph (r) of this section to the Administrator through the appropriate Regional Office.

(u)(3) The Administrator's authority for reviewing a source or modification located on an Indian Reservation shall not be redelegated other than to a Regional Office of the Environmental Protection Agency, except where the State has assumed jurisdiction over such land under other laws. Where the State has assumed such jurisdiction, the Administrator may delegate his authority to the States in accordance with paragraph (v)(2) of this section.

(u)(4) In the case of a source or modification which proposes to construct in a class III area, emissions from which would cause or contribute to air quality exceeding the maximum allowable increase applicable if the area were designated a class II area, and where no standard under section 111 of the act has been promulgated for such source category, the Administrator must approve the determination of best available control technology as set forth in the permit.

(v) *Innovative control technology.* (1) An owner or operator of a proposed major stationary source or major modification may request the Administrator in writing no later than the close of the comment period under 40 CFR 124.10 to approve a system of innovative control technology.

(v)(2) The Administrator shall, with the consent of the governor(s) of the affected state(s), determine that the source or modification may employ a system of innovative control technology, if:--

(v)(2)(i) The proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function;

(v)(2)(ii) The owner or operator agrees to achieve a level of continuous emissions reduction equivalent to that which would have been required under paragraph (j)(2) of this section, by a date specified by the Administrator. Such date shall not be later than 4 years from the time of startup or 7 years from permit issuance;

(v)(2)(iii) The source or modification would meet the requirements of paragraphs (j) and (k) of this section, based on the emissions rate that the stationary source employing the system of innovative control technology would be required to meet on the date specified by the Administrator;

(v)(2)(iv) The source or modification would not before the date specified by the Administrator:

(v)(2)(iv)(*a*) Cause or contribute to a violation of an applicable national ambient air quality standard; or

(v)(2)(iv)(*b*) Impact any area where an applicable increment is known to be violated; and

(v)(2)(v) All other applicable requirements including those for public participation have been met.

(v)(2)(vi) The provisions of paragraph (p) of this section (relating to Class I areas) have been satisfied with respect to all periods during the life of the source or modification.

(v)(3) The Administrator shall withdraw any approval to employ a system of innovative control technology made under this section, if:

(v)(3)(i) The proposed system fails by the specified date to achieve the required continuous emissions reduction rate; or

(v)(3)(ii) The proposed system fails before the specified date so as to contribute to an unreasonable risk to public health, welfare, or safety; or

(v)(3)(iii) The Administrator decides at any time that the proposed system is unlikely to achieve the required level of control or to protect the public health, welfare, or safety.

(v)(4) If a source or modification fails to meet the required level of continuous emission reduction within the specified time period or the approval is withdrawn in accordance with paragraph (v)(3) of this section, the Administrator may allow the source or modification up to an additional 3 years to meet the requirement for the application of best available control technology through use of a demonstrated system of control.

(w) *Permit recission.* (1) Any permit issued under this section or a prior version of this section shall remain in effect, unless and until it expires under paragraph (s) of this section or is rescinded.

(w)(2) Any owner or operator of a stationary source or modification who holds a permit for the source or modification which was issued under 40 CFR 52.21 as in effect on July 30, 1987, or any earlier version of this section, may request that the Administrator rescind the permit or a particular portion of the permit.

(w)(3) The Administrator shall grant an application for rescission if the application shows that this section would not apply to the source or modification.

(w)(4) If the Administrator rescinds a permit under this paragraph, the public shall be given adequate notice of the rescission. Publication of an announcement of rescission in a newspaper of general circulation in the affected region within 60 days of the rescisson shall be considered adequate notice.

(x) *Clean Unit Test for emissions units that are subject to BACT or LAER.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (x)(1) through (9) of this section.

(x)(1) *Applicability.* The provisions of this paragraph (x) apply to any emissions unit for which a reviewing authority has issued a major NSR permit within the last 10 years.

(x)(2) *General provisions for Clean Units.* The provisions in paragraphs (x)(2)(i) through (iv) of this section apply to a Clean Unit.

(x)(2)(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (x)(4) of this section) and before the expiration date (as determined in accordance with paragraph (x)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(x)(2)(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT and the project would not alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(x)(2)(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or the project would alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (x)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(x)(2)(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(x)(3) *Qualifying or re-qualifying to use the Clean Unit Applicability Test.* An emissions unit automatically qualifies as a Clean Unit when the unit meets the criteria in paragraphs (x)(3)(i) and (ii) of this section. After the original Clean Unit expires in accordance with paragraph (x)(5) of this section or is lost pursuant to paragraph (x)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (x)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (y) of this section. To re-qualify as a Clean Unit under paragraph (x)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable PSD program and meet all the criteria in paragraph (x)(3)(iii) of this section. The Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(x)(3)(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the last 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(x)(3)(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (x)(3)(ii)(*a*) and (*b*) of this section.

(x)(3)(ii)(*a*) The control technology achieves the BACT or LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for the Clean Unit designation if the BACT determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(x)(3)(ii)(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(x)(3)(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day BACT (or LAER), and the emissions unit must meet the requirements in paragraphs (x)(3)(i) and (x)(3)(ii) of this section.

(x)(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (x)(4)(i) or (x)(4)(ii) of this section.

(x)(4)(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing new control technology to meet current-day BACT.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than March 3, 2003, that is the date these provisions become effective.

(x)(4)(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(x)(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (x)(5)(i) or (ii) of this section.

(x)(5)(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day BACT.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (x)(3)(i) and (ii) of this section or re-qualifies by implementing new control technology to meet current-day BACT under paragraph (x)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(x)(5)(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (x)(3)(iii) of this section using an existing control technology, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(x)(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions in paragraphs (x)(6)(i) through (vi) of this section related to the Clean Unit.

(x)(6)(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(x)(6)(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.*, because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(x)(6)(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(x)(6)(iv) All emission limitations and work practice requirements adopted in conjunction with BACT, and any physical or operational characteristics which formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(x)(6)(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (x)(7) of this section.)

(x)(6)(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (x)(7) of this section.

(x)(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (x)(7)(i) through (iii) of this section. This paragraph (x)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(x)(7)(i) The Clean Unit must comply with the emission limitation(s) and/ or work practice requirements adopted in conjunction with the BACT that is recorded in the major NSR permit, and subsequently reflected in the title V permit. The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(x)(7)(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(x)(7)(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(x)(8) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a "netting analysis"), unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(x)(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by re-designation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(y) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to BACT.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (y)(1) through (11) of this section.

(y)(1) *Applicability.* The provisions of this paragraph (y) apply to emissions units which do not qualify as Clean Units under paragraph (x) of this section, but which are achieving a level of emissions control comparable to BACT, as determined by the Administrator in accordance with this paragraph (y).

(y)(2) *General provisions for Clean Units.* The provisions in paragraphs (y)(2)(i) through (iv) of this section apply to a Clean Unit (designated under this paragraph (y)).

(y)(2)(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (y)(5) of this section) and before the expiration date (as determined in accordance with paragraph (y)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(y)(2)(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(y)(2)(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (u)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(y)(2)(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(y)(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (y)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (y)(6) of this section or is lost pursuant to paragraph (y)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (y)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (x) of this section. To re-qualify as a Clean Unit under paragraph (y)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (y)(7) and (8) of this section and meet all the criteria in paragraph (y)(3)(iv) of this section. The Administrator will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(y)(3)(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (y)(3)(i)(*a*) and (*b*) of this section.

(y)(3)(i)(*a*) The owner or operator has demonstrated that the emissions unit's control technology is comparable to BACT according to the requirements of paragraph (y)(4) of this section. However, the emissions unit is not eligible for a Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.*, if the BACT determinations to which it is compared have resulted in a determination that no control measures are required).

(y)(3)(i)(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(y)(3)(ii) *Impact of emissions from the unit.* The Administrator must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(y)(3)(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before March 3, 2003. However, for such emissions units, the owner or operator must apply for the Clean Unit designation before December 31, 2004. For technologies installed on and after March 3, 2003, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(y)(3)(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (y)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day BACT, and the emissions unit must meet the requirements in paragraphs (y)(3)(i)(a) and (y)(3)(ii) of this section.

(y)(4) *Demonstrating control effectiveness comparable to BACT.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to BACT for purposes of paragraph (y)(3)(i) of this section according to either paragraph (y)(4)(i) or (ii) of this section. Paragraph (y)(4)(iii) of this section specifies the time for making this comparison.

(y)(4)(i) *Comparison to previous BACT and LAER determinations.* The Administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. The Administrator shall also compare this presumption to any additional BACT or LAER determinations of which he or she is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

(y)(4)(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as BACT. In addition, any other person may present evidence related to whether the control technology is substantially as effective as BACT during the public participation process required under paragraph (y)(7) of this section. The Administrator shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as BACT.

(y)(4)(iii) *Time of comparison.*

(y)(4)(iii)(*a*) *Emissions units with control technologies that are installed before March 3, 2003.* The owner or operator of an emissions unit whose control technology is installed before March 3, 2003 may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (y)(6) of this section.

(y)(4)(iii)(*b*) *Emissions units with control technologies that are installed on and after March 3, 2003.* The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements.

(y)(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major modification) is the date that the permit required by paragraph (y)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(y)(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (y)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (y)(9) of this section.

(y)(7) *Procedures for designating emissions units as Clean Units.* The Administrator shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§51.160 through 51.164 of this chapter including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (y)(8) of this section.

(y)(8) *Required permit content.* The permit required by paragraph (y)(7) of this section shall include the terms and conditions set forth in paragraphs (y)(8)(i) through (vi) of this section. Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(y)(8)(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(y)(8)(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(y)(8)(iii) The expiration date of the Clean Unit designation. If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(y)(8)(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to BACT, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(y)(8)(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (y)(9) of this section.)

(y)(8)(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (y)(9) of this section.

(y)(9) *Maintaining a Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (y)(9)(i) through (v) of this section. This paragraph (y)(9) applies independently to each pollutant for which the Administrator has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(y)(9)(i) The Clean Unit must comply with the emission limitation(s) and/ or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to BACT.

(y)(9)(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(y)(9)(iii) [Reserved]

(y)(9)(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(y)(9)(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(y)(10) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a "netting analysis") unless such use occurs before March 3, 2003 or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(y)(11) *Effect of redesignation on a Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (x)(2)(iii) and (y)(2)(iii) of this section, it must re-qualify under the requirements that are currently applicable.

(z) *PCP exclusion procedural requirements.* PCPs shall be provided according to the provisions in paragraphs (z)(1) through (6) of this section.

(z)(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the Administrator if the project is listed in paragraphs (b)(32)(i) through (vi) of this section, or if the project is not listed in paragraphs (b)(32)(i) through (vi) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the Administrator consistent with the requirements in paragraph (z)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (z)(2) of this section, and the notice or permit application must contain the information required in paragraph (z)(3) of this section.

(z)(2) Any project that relies on the PCP exclusion must meet the requirements of paragraphs (z)(2)(i) and (ii) of this section.

(z)(2)(i) *Environmentally beneficial analysis.* The environmental benefit from the emissions reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (b)(32)(i) through (vi) of this section is being used shall be presumed to satisfy this requirement.

(z)(2)(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(z)(3) *Content of notice or permit application.* In the notice or permit application sent to the Administrator, the owner or operator must include, at a minimum, the information listed in paragraphs (z)(3)(i) through (v) of this section.

(z)(3)(i) A description of the project.

(z)(3)(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(2)(iv) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (z)(2)(i) of this section.

(z)(3)(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71 of this chapter.

(z)(3)(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(z)(3)(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (z)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant that will not experience a significant emissions increase as a result of the project.

(z)(4) *Notice process for listed projects.* For projects listed in paragraphs (b)(32)(i) through (vi) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the Administrator (unless otherwise prohibited under requirements of the applicable State Implementation Plan). The owner or operator shall respond to any requests by the Administrator for additional information that the Administrator determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(z)(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (b)(32)(i) through (vi) of this section, the project must be approved by the Administrator and recorded in a State Implementation Plan-approved permit or title V permit using procedures that are consistent with §§51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The Administrator must address all material comments received by the end of the comment period before taking final action on the permit.

(z)(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (z)(6)(i) through (iv) of this section.

(z)(6)(i) *General duty.* The owner or operator must operate the PCP in a manner consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (z)(3) of this section, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(z)(6)(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (z)(6)(i) of this section.

(z)(6)(iii) *Permit requirements.* The owner or operator must comply with any provisions in the State Implementation Plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(z)(6)(iv) *Generation of emission reduction credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation). The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(aa) *Actuals PALs.* The provisions in paragraphs (aa)(1) through (15) of this section govern actuals PALs.

(aa)(1) *Applicability.*

(aa)(1)(i) The Administrator may approve the use of an actuals PAL for any existing major stationary source if the PAL meets the requirements in paragraphs (aa)(1) through (15) of this section. The term "PAL" shall mean "actuals PAL" throughout paragraph (aa) of this section.

(aa)(1)(ii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (aa)(1) through (15) of this section, and complies with the PAL permit:

(aa)(1)(ii)(*a*) Is not a major modification for the PAL pollutant;

(aa)(1)(ii)(*b*) Does not have to be approved through the PSD program; and

(aa)(1)(ii)(*c*) Is not subject to the provisions in paragraph (r)(4) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program).

(aa)(1)(iii) Except as provided under paragraph (aa)(1)(ii)(*c*) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(aa)(2) *Definitions.* For the purposes of this section, the definitions in paragraphs (aa)(2)(i) through (xi) of this section apply. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (b) of this section or in the Act.

(aa)(2)(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (b)(48) of this section) of all emissions units (as defined in paragraph (b)(7) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(aa)(2)(ii) *Allowable emissions* means "allowable emissions" as defined in paragraph (b)(16) of this section, except as this definition is modified according to paragraphs (aa)(2)(ii)(*a*) and (*b*) of this section.

(aa)(2)(ii)(*a*) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(aa)(2)(ii)(*b*) An emissions unit's potential to emit shall be determined using the definition in paragraph (b)(4) of this section, except that the words "or enforceable as a practical matter" should be added after "federally enforceable."

(aa)(2)(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (b)(23) of this section or in the Act, whichever is lower.

(aa)(2)(iv) *Major emissions unit* means:

(aa)(2)(iv)(*a*) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(aa)(2)(iv)(*b*) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(aa)(2)(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (aa)(1) through (15) of this section.

(aa)(2)(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(aa)(2)(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(aa)(2)(viii) *PAL major modification* means, notwithstanding paragraphs (b)(2) and (b)(3) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(aa)(2)(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the State Implementation Plan, or the title V permit issued by the Administrator that establishes a PAL for a major stationary source.

(aa)(2)(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(aa)(2)(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (b)(23) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (aa)(2)(iv) of this section.

(aa)(3) *Permit application requirements*. As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information to the Administrator for approval:

(aa)(3)(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations, or work practices apply to each unit.

(aa)(3)(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown, and malfunction.

(aa)(3)(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (aa)(13)(i) of this section.

(aa)(4) *General requirements for establishing PALs*.

(aa)(4)(i) The Administrator is allowed to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (aa)(4)(i)(a) through (g) of this section are met.

(aa)(4)(i)(*a*) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(aa)(4)(i)(*b*) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (aa)(5) of this section.

(aa)(4)(i)(*c*) The PAL permit shall contain all the requirements of paragraph (aa)(7) of this section.

(aa)(4)(i)(*d*) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(aa)(4)(i)(*e*) Each PAL shall regulate emissions of only one pollutant.

(aa)(4)(i)(*f*) Each PAL shall have a PAL effective period of 10 years.

(aa)(4)(i)(*g*) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (aa)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(aa)(4)(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant that occur during the PAL effective period creditable as decreases for purposes of offsets under §51.165(a)(3)(ii) of this chapter unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(aa)(5) *Public participation requirements for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased through a procedure that is consistent with §§51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The Administrator must address all material comments before taking final action on the permit.

(aa)(6) *Setting the 10-year actuals PAL level.* (i) Except as provided in paragraph (aa)(6)(ii) of this section, the plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(48) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(aa)(6)(ii) For newly constructed units (which do not include modifications to existing units) on which actual construction began after the 24-month period, in lieu of adding the baseline actual emissions as specified in paragraph (aa)(6)(i) of this section, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

(aa)(7) *Contents of the PAL permit.* The PAL permit must contain, at a minimum, the information in paragraphs (aa)(7)(i) through (x) of this section.

(aa)(7)(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(aa)(7)(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(aa)(7)(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (aa)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by a reviewing authority.

(aa)(7)(iv) A requirement that emission calculations for compliance purposes must include emissions from startups, shutdowns, and malfunctions.

(aa)(7)(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (aa)(9) of this section.

(aa)(7)(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total as required by paragraph (aa)(13)(i) of this section.

(aa)(7)(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (aa)(12) of this section.

(aa)(7)(viii) A requirement to retain the records required under paragraph (aa)(13) of this section on site. Such records may be retained in an electronic format.

(aa)(7)(ix) A requirement to submit the reports required under paragraph (aa)(14) of this section by the required deadlines.

(aa)(7)(x) Any other requirements that the Administrator deems necessary to implement and enforce the PAL.

(aa)(8) *PAL effective period and reopening of the PAL permit.* The requirements in paragraphs (aa)(8)(i) and (ii) of this section apply to actuals PALs.

(aa)(8)(i) *PAL effective period.* The Administrator shall specify a PAL effective period of 10 years.

(aa)(8)(ii) *Reopening of the PAL permit.*

(aa)(8)(ii)(*a*) During the PAL effective period, the Administrator must reopen the PAL permit to:

(aa)(8)(ii)(*a*)(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL;

(aa)(8)(ii)(*a*)(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under §51.165(a)(3)(ii) of this chapter; and

(aa)(8)(ii)(*a*)(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (aa)(11) of this section.

(aa)(8)(ii)(*b*) The Administrator shall have discretion to reopen the PAL permit for the following:

(aa)(8)(ii)(*b*)(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date;

(aa)(8)(ii)(*b*)(2) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the State Implementation Plan; and

(aa)(8)(ii)(*b*)(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(aa)(8)(ii)(*c*) Except for the permit reopening in paragraph (aa)(8)(ii)(*a*)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of paragraph (aa)(5) of this section.

(aa)(9) *Expiration of a PAL.* Any PAL that is not renewed in accordance with the procedures in paragraph (aa)(10) of this section shall expire at the end of the PAL effective period, and the requirements in paragraphs (aa)(9)(i) through (v) of this section shall apply.

(aa)(9)(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (aa)(9)(i)(*a*) and (*b*) of this section.

(aa)(9)(i)(*a*) Within the time frame specified for PAL renewals in paragraph (aa)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the Administrator) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (aa)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(aa)(9)(i)(*b*) The Administrator shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Administrator determines is appropriate.

(aa)(9)(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The Administrator may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS, or CPMS to demonstrate compliance with the allowable emission limitation.

(aa)(9)(iii) Until the Administrator issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (aa)(9)(i)(*b*) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(aa)(9)(iv) Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in paragraph (b)(2) of this section.

(aa)(9)(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (r)(4) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (aa)(1)(ii)(c) of this section.

(aa)(10) *Renewal of a PAL.*

(aa)(10)(i) The Administrator shall follow the procedures specified in paragraph (aa)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the Administrator.

(aa)(10)(ii) *Application deadline.* A major stationary source owner or operator shall submit a timely application to the Administrator to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(aa)(10)(*iii*) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (aa)(10)(iii)(*a*) through (*d*) of this section.

(aa)(10)(iii)(*a*) The information required in paragraphs (aa)(3)(i) through (iii) of this section.

(aa)(10)(iii)(*b*) A proposed PAL level.

(aa)(10)(iii)(*c*) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(aa)(10)(iii)(*d*) Any other information the owner or operator wishes the Administrator to consider in determining the appropriate level for renewing the PAL.

(aa)(10)(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the Administrator shall consider the options outlined in paragraphs (aa)(10)(iv)(*a*) and (*b*) of this section. However, in no case may any such adjustment fail to comply with paragraph (aa)(10)(iv)(*c*) of this section.

(aa)(10)(iv)(*a*) If the emissions level calculated in accordance with paragraph (aa)(6) of this section is equal to or greater than 80 percent of the PAL level, the Administrator may renew the PAL at the same level without considering the factors set forth in paragraph (aa)(10)(iv)(*b*) of this section; or

(aa)(10)(iv)(*b*) The Administrator may set the PAL at a level that he or she determines to be more representative of the source's baseline actual emissions, or that he or she determines to be more appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the Administrator in his or her written rationale.

(aa)(10)(iv)(*c*) Notwithstanding paragraphs (aa)(10)(iv)(*a*) and (*b*) of this section:

(aa)(10)(iv)(c)(*1*) If the potential to emit of the major stationary source is less than the PAL, the Administrator shall adjust the PAL to a level no greater than the potential to emit of the source; and

(aa)(10)(iv)(c)(*2*) The Administrator shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (aa)(11) of this section (increasing a PAL).

(aa)(10)(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the Administrator has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(aa)(11) *Increasing a PAL during the PAL effective period.*

(aa)(11)(i) The Administrator may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (aa)(11)(i)(*a*) through (*d*) of this section.

(aa)(11)(i)(*a*) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(aa)(11)(i)(*b*) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(aa)(11)(i)(*c*) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (aa)(11)(i)(*a*) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT), even though they have also become subject to the PAL or continue to be subject to the PAL.

(aa)(11)(i)(*d*) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(aa)(11)(ii) The Administrator shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (aa)(11)(i)(*b*)), plus the sum of the baseline actual emissions of the small emissions units.

(aa)(11)(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (aa)(5) of this section.

(aa)(12) *Monitoring requirements for PALs.* (i) General requirements. (*a*) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(aa)(12)(i)(*b*) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (aa)(12)(ii)(*a*) through (*d*) of this section and must be approved by the Administrator.

(aa)(12)(i)(*c*) Notwithstanding paragraph (aa)(12)(i)(*b*) of this section, you may also employ an alternative monitoring approach that meets paragraph (aa)(12)(i)(*a*) of this section if approved by the Administrator.

(aa)(12)(i)(*d*) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(aa)(12)(ii) Minimum performance requirements for approved monitoring approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (aa)(12)(iii) through (ix) of this section:

(aa)(12)(ii)(*a*) Mass balance calculations for activities using coatings or solvents;

(aa)(12)(ii)(*b*) CEMS;

(aa)(12)(ii)(*c*) CPMS or PEMS; and

(aa)(12)(ii)(*d*) Emission factors.

(aa)(12)(iii) Mass balance calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(aa)(12)(iii)(*a*) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(aa)(12)(iii)(*b*) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(aa)(12)(iii)(*c*) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the Administrator determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(aa)(12)(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(aa)(12)(iv)(*a*) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(aa)(12)(iv)(*b*) CEMS must sample, analyze and record data at least every 15 minutes while the emissions unit is operating.

(aa)(12)(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(aa)(12)(v)(*a*) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(aa)(12)(v)(*b*) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the Administrator, while the emissions unit is operating.

(aa)(12)(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(aa)(12)(vi)(*a*) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(aa)(12)(vi)(*b*) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(aa)(12)(vi)(*c*) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the Administrator determines that testing is not required.

(aa)(12)(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(aa)(12)(viii) Notwithstanding the requirements in paragraphs (aa)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the Administrator shall, at the time of permit issuance:

(aa)(12)(viii)(*a*) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(aa)(12)(viii)(*b*) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(aa)(12)(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the Administrator.

Such testing must occur at least once every 5 years after issuance of the PAL.

(aa)(13) *Recordkeeping requirements.* (i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (aa) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(aa)(13)(ii) The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus 5 years:

(aa)(13)(ii)(*a*) A copy of the PAL permit application and any applications for revisions to the PAL; and

(aa)(13)(ii)(*b*) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(aa)(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the Administrator in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (aa)(14)(i) through (iii) of this section.

(aa)(14)(i) *Semi-annual report.* The semi-annual report shall be submitted to the Administrator within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (aa)(14)(i)(*a*) through (*g*) of this section.

(aa)(14)(i)(*a*) The identification of owner and operator and the permit number.

(aa)(14)(i)(*b*) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (aa)(13)(i) of this section.

(aa)(14)(i)(*c*) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(aa)(14)(i)(*d*) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(aa)(14)(i)(*e*) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(aa)(14)(i)(*f*) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by (aa)(12)(vii).

(aa)(14)(i)(*g*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(aa)(14)(ii) *Deviation report.* The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to §70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing §70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(aa)(14)(ii)(*a*) The identification of owner and operator and the permit number;

(aa)(14)(ii)(*b*) The PAL requirement that experienced the deviation or that was exceeded;

(aa)(14)(ii)(*c*) Emissions resulting from the deviation or the exceedance; and

(aa)(14)(ii)(*d*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(aa)(14)(iii) *Re-validation results.* The owner or operator shall submit to the Administrator the results of any re-validation test or method within 3 months after completion of such test or method.

(aa)(15) *Transition requirements.*

(aa)(15)(i) The Administrator may not issue a PAL that does not comply with the requirements in paragraphs (aa)(1) through (15) of this section after March 3, 2003.

(aa)(15)(ii) The Administrator may supersede any PAL that was established prior to March 3, 2003 with a PAL that complies with the requirements of paragraphs (aa)(1) through (15) of this section.

(bb) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

(cc) Without regard to other considerations, routine maintenance, repair and replacement includes, but is not limited to, the replacement of any component of a process unit with an identical or functionally equivalent component(s), and maintenance and repair activities that are part of the replacement activity, provided that all of the requirements in paragraphs (cc)(1) through (3) of this section are met.

(cc)(1) *Capital cost threshold for equipment replacement.* (i) For an *electric utility steam generating unit,* as defined in §52.21(b)(31), the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced. For a process unit that is not an electric utility steam generating unit the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced.

(cc)(1)(ii) In determining the replacement value of the process unit; and, except as otherwise allowed under paragraph (cc)(1)(iii) of this section, the owner or operator shall determine the replacement value of the process unit on an estimate of the fixed capital cost of constructing a new process unit, or on the current appraised value of the process unit.

(cc)(1)(iii) As an alternative to paragraph (cc)(1)(ii) of this section for determining the replacement value of a process unit, an owner or operator may choose to use insurance value (where the insurance value covers only complete replacement), investment value adjusted for inflation, or another accounting procedure if such procedure is based on Generally Accepted Accounting Principles, provided that the owner or operator sends a notice to the reviewing authority. The first time that an owner or operator submits such a notice for a particular process unit, the notice may be submitted at any time, but any subsequent notice for that process unit may be submitted only at the beginning of the process unit's fiscal year. Unless the owner or operator submits a notice to the reviewing authority, then paragraph (cc)(1)(ii) of this section will be used to establish the replacement value of the process unit. Once the owner or operator submits a notice to use an alternative accounting procedure, the owner or operator must continue to use that procedure for the entire fiscal year for that process unit. In subsequent fiscal years, the owner or operator must continue to use this selected procedure unless and until the owner or operator sends another notice to the reviewing authority selecting another procedure consistent with this paragraph or paragraph (cc)(1)(ii) of this section at the beginning of such fiscal year.

(cc)(2) *Basic design parameters.* The replacement does not change the basic design parameter(s) of the process unit to which the activity pertains.

(cc)(2)(i) Except as provided in paragraph (cc)(2)(iii) of this section, for a process unit at a steam electric generating facility, the owner or operator may select as its basic design parameters either maximum hourly heat input and maximum hourly fuel consumption rate or maximum hourly electric output rate and maximum steam flow rate. When establishing fuel consumption specifications in terms of weight or volume, the minimum fuel quality based on British Thermal Units content shall be used for determining the basic design parameter(s) for a coal-fired electric utility steam generating unit.

(cc)(2)(ii) Except as provided in paragraph (cc)(2)(iii) of this section, the basic design parameter(s) for any process unit that is not at a steam electric generating facility are maximum rate of fuel or heat input, maximum rate of material input, or maximum rate of product output. Combustion process units will typically use maximum rate of fuel input. For sources having multiple end products and raw materials, the owner or operator should consider the primary product or primary raw material when selecting a basic design parameter.

(cc)(2)(iii) If the owner or operator believes the basic design parameter(s) in paragraphs (cc)(2)(i) and (ii) of this section is not appropriate for a specific industry or type of process unit, the owner or operator may propose to the reviewing authority an alternative basic design parameter(s) for the source's process unit(s). If the reviewing authority approves of the use of an alternative basic design parameter(s), the reviewing authority shall issue a permit that is legally enforceable that records such basic design parameter(s) and requires the owner or operator to comply with such parameter(s).

(cc)(2)(iv) The owner or operator shall use credible information, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations, in establishing the magnitude of the basic design parameter(s) specified in paragraphs (cc)(2)(i) and (ii) of this section.

(cc)(2)(v) If design information is not available for a process unit, then the owner or operator shall determine the process unit's basic design parameter(s) using the maximum value achieved by the process unit in the five-year period immediately preceding the planned activity.

(cc)(2)(vi) Efficiency of a process unit is not a basic design parameter.

(cc)(3) The replacement activity shall not cause the process unit to exceed any emission limitation, or operational limitation that has the effect of constraining emissions, that applies to the process unit and that is legally enforceable.

Note to paragraph (cc): By a court order on December 24, 2003, this paragraph (cc) is stayed indefinitely. The stayed provisions will become effective immediately if the court terminates the stay. At that time, EPA will publish a document in the **Federal Register** advising the public of the termination of the stay.

[43 FR 26403, June 19, 1978, as amended at 44 FR 27571, May 10, 1979; 45 FR 52735, Aug. 7, 1980; 47 FR 27561, June 25, 1982; 49 FR 43209, Oct. 26, 1984; 50 FR 28550, July 12, 1985; 51 FR 40675, 40677, Nov. 7, 1986; 52 FR 24714, July 1, 1987; 52 FR 26401, July 14, 1987; 53 FR 396, Jan. 6, 1988; 53 FR 40671, Oct. 17, 1988; 54 FR 27285, 27300 June 28, 1989; 56 FR 5506, Feb. 11, 1991; 57 FR 3946, Feb. 3, 1992; 57 FR 32336; July 21, 1992; 58 FR 31622, June 3, 1993; 58 FR 38816, July 20, 1993; 58 FR 34369, June 25,1993; 60 FR 40465, Aug. 9, 1995; 61 FR 9905, Mar. 12, 1996; 61 FR 41838, Aug. 12, 1996; 67 FR 80186, Dec. 31, 2002; 68 FR 61248, Oct. 27, 2003; 68 FR 63021, Nov. 7, 2003; 69 FR 40274, July 1, 2004; 70 FR 36036, June 22, 2005; 70 FR 71612, Nov. 29, 2005]

Prev TOC Next

RegScan Citation: 40CFR52.21

Kentucky Power Company

REQUEST

Refer to Exhibit 3 of the Application. In Kentucky Power's two previous environmental compliance plan amendment and surcharge modification proceedings, Case Nos. 2002-00169 and 2005-00068, the Commission approved an Environmental Surcharge ("ES") Tariff for service rendered on and after a specific date. In light of those previous Commission decisions, explain why Kentucky Power proposes that the changes to its ES Tariff should become effective with bills rendered on and after a specific date.

RESPONSE

When a tariff is approved for service rendered on and after a specific date requires the utility to estimate the customer's usage between the last billing date and the tariff's effective date. When a tariff is effective with bills rendered on and after a specific date eliminates any required estimation. The Company believes billings, which reduce the level of estimation, are more accurate.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Errol K Wagner ("Wagner Testimony"), page 12, and Exhibit EKW-1. In discussing the impact of the proposed amendment to the environmental compliance plan and amendment to the environmental surcharge, Mr. Wagner notes that retirements associated with some of the projects have not been included in the calculations due to the fact Kentucky Power has not estimated or forecasted the associated retirements.

a. Using a copy of Exhibit EKW-1, indicate the projects that are expected or can be reasonably expected to have retirements associate with the project.

b. When would Kentucky Power or AEP be estimating or forecasting the costs of any existing plant retired as a result of the proposed projects? Explain the response.

RESPONSE

a. Any project that has an amount in the "Removal" column on the Project Approval Requisition (CI) is expected or can be reasonably expected to have retirements associated with the project. The Projects listed on Exhibit EKW-1 only the Mitchell Impoundment has an amout of $200,000 in the "Removal" column. The Company expects, based on past experience, other projects will have some retirements associated with these projects. However, at this time that information is unknown.

b. The Company does not typically forecast the specific cost of existing plant to be retired prior to the recording of the actual retirement. The actual retirement is recorded when a project is placed into service.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to the Wagner Testimony, Exhibit EKW-1. For each project listed on this exhibit, provide documentation supporting the amounts reported as the "Cost of Environmental Facilities".

RESPONSE

Please see the Company's response to Item No. 4 part b for supporting documentation.

Please note on Exhibit EKW-1, Lines 1 through 8, Amos Unit No. 3, the individual amounts reflected in column 9 are different than the amounts listed on the OPCo CI AM003FGDO page 3 of 6. However, the difference between the total amount shown on the CI is only $6,000 from the total amount shown on Exhibit EKW-1 for Lines 1 through 8 ($389,820 - ($9,962 + $62,246)). This correction has no effect on the annual revenue requirement of Kentucky Power Company.

Attached is a revised EKW-1 showing the following revisions:

Line 41, Mitchell Unit Nos. 1 and 2, Impoundment, the amount of $9,844 should read $9,644. The removal costs on the CI should not have been included on the original Exhibit EKW-1.

Lines 47 and 48, Rockport Units 1 and 2, Landfill, the original amount of $2,500,000 was picked up in error the correct amount should have been $499 for each unit.

Line 50, Tanners Creek Common should have read Tanners Creek Unit No. 4.

Attached is a Revised copy of Exhibit EKW-1 showing the above three changes (See Pages 2 through 4 attached).

None of the above changes change the $2.67 "Effect on Wgt. Ave. Rate" shown on Exhibit EKW-4, line 12.

Also, attached is reconciliation showing the source of the amounts shown on Exhibit EKW-1 (See Pages 5 through 8 attached).

WITNESS: Errol K Wagner

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities
in Thousand of Dollars

Exhibit EKW-1
Page 1 of 3
Revised Sept. 08, 2006

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In-Service Date (4)	Cost of Environmental Facilities (5)	Less Cost of Original (6)	OPCo or I & M Percentage (7)	OPCo's Envir. Invest. (8)	I&M's Envir. Invest. (9)
1	Amos Unit No. 3	FGD	4Q-07	$346,121	$0	66.67%	$230,779	
2	Amos Unit No. 3	Balance Draft Conversion	4Q-07	$39,923	$0	66.67%	$26,613	
3	Amos Unit No. 3	Controls Modernization	4Q-07	$14,141	$0	66.67%	$9,448	
4	Amos Unit No. 3	Steam Generator Modifications	4Q-07	$6,091	$0	66.67%	$4,081	
5	Amos Unit No. 3	SO3 Mitigation	4Q-07	$14,066	$0	66.67%	$9,398	
6	Amos Unit No. 3	FGD Purge Steam Water Treatment System	4Q-07	$9,400	$0	66.67%	$6,287	
7	Amos Unit No. 3	Plant Common Equipment	4Q-07	$90,797	$0	29.89%	$27,159	
8	Amos Unit No. 3	Coal Blending Station	4Q-07	$5,740	$0	66.67%	$3,847	
9	Amos Unit Nos. 1, 2 & 3	Landfill	4Q-07	$33,263	$0	29.89%	$9,962	
10	Amos Unit No. 3	Precip Modification	4Q-07	$93,365	$0	66.67%	$62,246	
11	Sub-Total			$652,907	$0		$389,820	
12	Cardinal Unit No. 1	FGD	4Q-07	$216,748	$0	100.00%	$216,748	
13	Cardinal Unit No. 1	Controls Modernization	4Q-07	$5,930	$0	100.00%	$5,930	
14	Cardinal Unit No. 1	Boiler Modification	4Q-07	$6,971	$0	100.00%	$6,971	
15	Cardinal Unit No. 1	Balance Draft Conversion	4Q-07	$30,530	$0	100.00%	$30,530	
16	Cardinal Unit No. 1	FD Fan Modification	4Q-07	$1,763		100.00%	$1,763	
17	Cardinal Unit No. 1	FGD Purge Stream Water Treatment System	4Q-07	$12,821	$0	100.00%	$12,821	
18	Cardinal Unit No. 1	SO3 Mitigation	4Q-07	$7,292	$0	100.00%	$7,292	
19	Cardinal Unit No. 1	Catalyst Replacement	4Q-07	$3,606	$0	100.00%	$3,606	
20	Cardinal Unit No. 1	Landfill	2Q-08	$15,703	$0	100.00%	$15,703	
21	Sub-Total			$301,364	$0		$301,364	
22	Gavin Units Nos 1 & 2	SO3 Mitigation	4Q-06	$9,997	$0	100.00%	$9,997	

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities
in Thousand of Dollars

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In-Service Date (4)	Cost of Environmental Facilities (5)	Less Cost of Original (6)	OPCo or I & M Percentage (7)	OPCo's Envir. Invest. (8)	I&M's Envir. Invest. (9)
23	Mitchell Unit No. 1	FGD	2Q-07	$242,906	$0	100.00%	$242,906	
24	Mitchell Unit No. 1	SCR	2Q-07	$133,771	$0	100.00%	$133,771	
25	Mitchell Unit No. 1	Balance Draft Conversion	2Q-07	$24,431	$0	100.00%	$24,431	
26	Mitchell Unit No. 1	Controls Modernization	2Q-07	$3,026	$0	100.00%	$3,026	
27	Mitchell Unit No. 1	Steam Generator Modifications	2Q-07	$10,262	$0	100.00%	$10,262	
28	Mitchell Unit No. 1	SO3 Mitigation	2Q-07	$14,827	$0	100.00%	$14,827	
29	Mitchell Unit No. 1	FGD Purge Stream Water Treatment System	2Q-07	$11,624	$0	100.00%	$11,624	
30	Mitchell Unit No. 1	Coal Blending Station	2Q-07	$12,280	$0	100.00%	$12,280	
31	Sub-Total			$453,127	$0		$453,127	
32	Mitchell Unit No. 2	FGD	4Q-06	$236,154	$0	100.00%	$236,154	
33	Mitchell Unit No. 2	SCR	2Q-07	$137,557	$0	100.00%	$137,557	
34	Mitchell Unit No. 2	Balance Draft Conversion	2Q-07	$24,431	$0	100.00%	$24,431	
35	Mitchell Unit No. 2	Controls Modernization	2Q-07	$3,026	$0	100.00%	$3,026	
36	Mitchell Unit No. 2	Steam Generator Modifications	2Q-07	$10,262	$0	100.00%	$10,262	
37	Mitchell Unit No. 2	SO3 Mitigation	2Q-07	$14,827	$0	100.00%	$14,827	
38	Mitchell Unit No. 2	FGD Purge Stream Water Treatment System	2Q-07	$11,624	$0	100.00%	$11,624	
39	Mitchell Unit No. 2	Coal Blending Station	2Q-07	$12,280	$0	100.00%	$12,280	
40	Sub-Total			$450,161	$0		$450,161	

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities
in Thousand of Dollars

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In-Service Date (4)	Cost of Environmental Facilities (5)	Less Cost of Original (6)	OPCo or I & M Percentage (7)	OPCo's Envir. Invest. (8)	I&M's Envir. Invest. (9)
41	Mitchell Unit Nos 1 & 2	Impoundment	4Q-06	$9,644 1/	$0	100.00%	$9,644	
42	Mitchell Unit Nos 1 & 2	Gypsum Material Handling	1Q-07	$33,228	$0	100.00%	$33,228	
43	Mitchell Unit Nos 1 & 2	Gypsum Material Handling	4Q--06	$13,123	$0	100.00%	$13,123	
44	Mitchell Unit Nos 1 & 2	Transformer Rectifier Set Replacement	4Q-06	$8,351	$0	100.00%	$8,351	
45	Sub-Total			$64,346	$0		$64,346	
46	Sporn Unit Nos 2,4 & 5	Landfill	4Q-08	$6,546	$0	100.00%	$6,546	
47	Rockport Unit No 1	Landfill	4Q-08	$499 3/	$0	85.00% *		$424
48	Rockport Unit No 2	Landfill	4Q-08	$499 3/	$0	65.08% *		$325
49	Sub-Total			$998	$0			$749
50	Tanners Creek Unit No. 4 2/	Coal Blending	2Q-06	$90,637	$0	100.00%		$90,637
51	Total Net Investment			$2,030,083	$0		$1,675,361	$91,386

* I&M's Share of Rockport Plant in the AEP Pool
Rockport Unit No. 1 = I&M 650 MW + AEGCo's 455MW (1105 MW / 1300 MW)
Rockport Unit No. 2 = I&M's 650 MW + AEGCo's 196 MW (846 MW / 1300MW)

1/ Cost of Removal was eliminated from the total capital costs.

2/ Tanners Creek Common was changed to Tanners Creek Unit No. 4.

3/ The Amount of $2,500,000 as originally filed was picked up in error.

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In Service Date (4)	Cost of Environmental Facilities per CI (5)	Cost of Environmental Facilities per Long Range Plan (6)	Cost of Environmental Facilities per Project Eng. Estimate (7)	Total (C5 + C6 + C7) (8)		Cost of Environmental Facilities Exhibit EWK-1 (Revised Sept. 08, 2006) (Columns 8 & 9) (9)	Difference (C9 - C8) (10)
1	Amos Unit No. 3	FGD	4Q-07	$230,862,650			$230,862,650		$230,779,000	($83,650)
	Associated Costs									
2	Amos Unit No. 3	Balance Draft Conversion	4Q-07	$26,628,748			$26,628,748		$26,613,000	($15,748)
3	Amos Unit No. 3	Controls Modernization	4Q-07	$9,431,870			$9,431,870		$9,448,000	$16,130
4	Amos Unit No. 3	Steam Generator Modifications	4Q-07	$4,062,864			$4,062,864		$4,081,000	$18,136
5	Amos Unit No. 3	SO3 Mitigation	4Q-07	$9,382,118			$9,382,118		$9,398,000	$15,882
6	Amos Unit No. 3	FGD Purge Steam Water Treatment System	4Q-07	$6,269,803			$6,269,803		$6,287,000	$17,197
7	Amos Unit No. 3	Plant Common Equipment	4Q-07	$27,139,275			$27,139,275		$27,159,000	$19,725
8	Amos Unit No. 3	Coal Blending Station	4Q-07	$3,828,581			$3,828,581		$3,847,000	$18,419
9	Total Associated Costs			$86,743,259			$86,743,259		$86,833,000	$89,741
10	Total Amos Unit 3 FGD Phase 3			$317,605,909			$317,605,909		$317,612,000	$6,091
11	Amos Unit Nos. 1, 2 & 3	Landfill	4Q-07		$33,262,602		$9,942,192	1/	$9,962,000	$19,808
12	Amos Unit No. 3	Precip Modification	4Q-07	$13,364,807		$80,000,000	$62,246,317	2/	$62,246,000	($317)
13	Total Amos Plant			$330,970,716	$33,262,602	$80,000,000	$389,794,418		$389,820,000	$25,582
14	Cardinal Unit No. 1	FGD	4Q-07		$216,748,420		$216,748,420		$216,748,000	($420)
	Associated Costs									
15	Cardinal Unit No. 1	Controls Modernization	4Q-07						$5,930,000	
16	Cardinal Unit No. 1	Boiler Modification	4Q-07						$6,971,000	
17	Cardinal Unit No. 1	Balance Draft Conversion	4Q-07						$30,530,000	
18	Cardinal Unit No. 1	FD Fan Modification	4Q-07						$1,763,000	
19	Cardinal Unit No. 1	FGD Purge Steam Water Treatment System	4Q-07						$12,821,000	
20	Cardinal Unit No. 1	SO3 Mitigation	4Q-07						$7,292,000	
21	Cardinal Unit No. 1	Catalyst Replacement	4Q-07						$3,606,000	

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In Service Date (4)	Cost of Environmental Facilities per CI (5)	Cost of Environmental Facilities per Long Range Plan (6)	Cost of Environmental Facilities per Project Eng. Estimate (7)	Total (C5 + C6 + C7) (8)	Cost of Environmental Facilities Exhibit EWK-1 (Revised Sept. 08, 2006) (Columns 8 & 9) (9)	Difference (C9 - C8) (10)
22	Total Associated Costs				$68,913,561		$68,913,561	$68,913,000	($561)
23	Total Cardinal Unit 1 FGD Phase 3				$285,661,981		$285,661,981	$285,661,000	($981)
24	Cardinal Unit No. 1	Landfill	2Q-08	$16,564,518	$15,703,417		$15,703,417	$15,703,000	($417)
25	Total Cardinal Plant Unit 1			$16,564,518	$301,365,398		$301,365,398	$301,364,000	($1,398)
26	Gavin Units Nos 1 & 2	SO3 Mitigation	4Q-06	$9,996,582			$9,996,582	$9,997,000	$418
27	Total Gavin Plant Units 1 & 2			$9,996,582			$9,996,582	$9,997,000	$418
28	Mitchell Unit No. 1	FGD	2Q-07		$242,906,262		$242,906,262	$242,906,000	($262)
	Associated Costs								
29	Mitchell Unit No. 1	Balance Draft Conversion	2Q-07					$24,431,000	
30	Mitchell Unit No. 1	Controls Modernization	2Q-07					$3,026,000	
31	Mitchell Unit No. 1	Steam Generator Modifications	2Q-07					$10,262,000	
32	Mitchell Unit No. 1	SO3 Mitigation	2Q-07					$14,827,000	
33	Mitchell Unit No. 1	FGD Purge Stream Water Treatment System	2Q-07					$11,624,000	
34	Mitchell Unit No. 1	Coal Blending Station	2Q-07					$12,280,000	
35	Total Associated Costs				$76,449,467		$76,449,467 3/	$76,450,000	$533
36	Total Mitchell Unit 1 FGD Phase 3				$319,355,729		$319,355,729	$319,356,000	$271
37	Mitchell Unit No. 1	SCR	2Q-07		$133,771,424		$133,771,424	$133,771,000	($424)
38	Total Mitchell Plant Unit 1				$453,127,153		$453,127,153	$453,127,000	($153)

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In Service Date (4)	Cost of Environmental Facilities per CI (5)	Cost of Environmental Facilities per Long Range Plan (6)	Cost of Environmental Facilities per Project Eng. Estimate (7)	Total (C5 + C6 + C7) (8)	Cost of Environmental Facilities Exhibit EWK-1 (Revised Sept. 08, 2006) (Columns 8 & 9) (9)	Difference (C9 - C8) (10)
39	Mitchell Unit No. 2	FGD	4Q-06		$236,154,132		$236,154,132	$236,154,000	($132)
	Associated Costs								
40	Mitchell Unit No. 2	Balance Draft Conversion	2Q-07					$24,431,000	
41	Mitchell Unit No. 2	Controls Modernization	2Q-07					$3,026,000	
42	Mitchell Unit No. 2	Steam Generator Modifications	2Q-07					$10,262,000	
43	Mitchell Unit No. 2	SO3 Mitigation	2Q-07					$14,827,000	
44	Mitchell Unit No. 2	FGD Purge Stream Water Treatment System	2Q-07					$11,624,000	
45	Mitchell Unit No. 2	Coal Blending Station	2Q-07					$12,280,000	
46	Total Associated Costs				$76,449,467		$76,449,467 3/	$76,450,000	$533
47	Total Mitchell Unit 2 FGD Phase 3				$312,603,599		$312,603,599	$312,604,000	$401
48	Mitchell Unit No. 2	SCR	2Q-07		$137,556,793		$137,556,793	$137,557,000	$207
49	Total Mitchell Plant Unit 2				$450,160,392		$450,160,392	$450,161,000	$608
50	Mitchell Unit Nos 1 & 2	Impoundment	4Q-06	$9,644,266			$9,644,266	$9,644,000	($266)
51	Mitchell Unit Nos 1 & 2	Gypsum Material Handling	1Q-07	$33,227,523			$33,227,523	$33,228,000	$477
52	Mitchell Unit Nos 1 & 2	Gypsum Material Handling	4Q--06	$13,123,084			$13,123,084	$13,123,000	($84)
53	Mitchell Unit Nos 1 & 2	Transformer Rectifier Set	4Q-06	$8,351,205			$8,351,205	$8,351,000	($205)
54	Total Mitchell Plant Units 1 & 2			$64,346,078			$64,346,078	$64,346,000	($78)
55	Sporn Units Nos 2, 4 & 5	Landfill	4Q-08	$6,546,032			$6,546,032	$6,546,000	($32)
56	Total Gavin Plant Units 1 & 2			$6,546,032			$6,546,032	$6,546,000	($32)

Kentucky Power Company
AEP Pool Surplus Companies
Net Investment In
Environmental Facilities

Ln. No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In Service Date (4)	Cost of Environmental Facilities per CI (5)	Cost of Environmental Facilities per Long Range Plan (6)	Cost of Environmental Facilities per Project Eng. Estimate (7)	Total (C5 + C6 + C7) (8)		Cost of Environmental Facilities Exhibit EWK-1 (Revised Sept. 08, 2006) (Columns 8 & 9) (9)	Difference (C9 - C8) (10)
57	Rockport Unit No 1	Landfill	4Q-08	$499,350			$424,448	4/	$424,000	($448)
58	Rockport Unit No 2	Landfill	4Q-08	$499,350			$324,977	4/	$325,000	$23
59	Total Rockport Plant Units 1 & 2			$998,700			$749,425		$749,000	($425)
60	Tanners Creek Unit 4	Coal Blending	2Q-06	$90,637,483			$90,637,483		$90,637,000	($483)
61	Total Tanners Creek Plant			$90,637,483			$90,637,483		$90,637,000	($483)
62	Total Net Investment			$520,060,109	$1,237,915,545	$80,000,000	$1,766,722,961		$1,766,747,000	$24,039

1/ Per the Long Range Plan Page 3

Amos Landfill - $45,,352,841 - $12,090,239 (Year 2009) = $33,262,602 @ 29.89% = $9,942,192

2/ Per CIs AMPOOO104 & AMPOOO488 ($13,364,807) and Project Engineer's Estimate ($80,000,000)

Amos Unit 3 Precipitator Modifications - $13,364,807 + $80,000,000 = $93,364,807 @ 66.67% = $62,246,317

3/ Per the Long Range Plan Page 4

Mitchell Units 1 & 2 Associated Costs - $152,898,934 / 2 = $76,449,467

4/ Per Cis RKIMC0652 & RKAEG0652 - $998,700

Rockport Unit 1 Landfill - $998,700 / 2 = $499,350 @ 85.00% = $424,448
Rockport Unit 2 Landfill - $998,700 / 2 = $499,350 @ 65.08% = $324,977

Kentucky Power Company

REQUEST

Assume for purposes of this question that the Commission approves Kentucky Power's amendment to its environmental compliance plan and modification to the surcharge mechanism as proposed. Indicate what schedules Kentucky Power would propose to include with the monthly environmental surcharge filing to document the additional environmental costs it was permitted to recover from ratepayers.

RESPONSE

The Company envisions changes to the format of the following monthly environmental schedules.

Schedule	Reason for Modification
ES Form 3.10	Description on Line 17
ES Form 3.13	Removed 1997 Plan & 2003 Plan in Heading
ES Form 3.14 Page 3 of 11	Added Lines 6, 9, 12 & 14
ES Form 3.14 Page 4 of 11	Added Lines 4, 7, 10 & 12
ES Form 3.14 Page 7 of 11	Added Lines 4, 7, 10, & 12

The net investment along with any associated O&M expenses associated with the facilities included in the 2006 Plan would be included in all of the already existing environmental schedules.

Below is a list of schedules and the associated Plants which the investment and any associated O&M expenses would be included. Again some of these schedules were modified to accommodate the associated environmental O&M expense.

Plant	ES Form
Amos Unit No. 3	3.14 page 3 of 11
Cardinal Unit No. 1	3.14 page 4 of 11
Gavin Unit Nos. 1 & 2	3.14 page 5 of 11
Mitchell Unit Nos. 1 & 2	3.14 page 7 of 11
Sporn Unit Nos. 2, 4 & 5	3.14 page 9 of 11
Rockport Unit Nos. 1 & 2	3.14 page 10 of 11 and ES Form 3.20
Tanners Creek Unit Nos. 1, 2, 3 & 4	3.14 page 11 of 11

Attached is a copy of the July 2006 expense month environmental monthly schedules as-filed along with the monthly costs associated with the 2006 Plan. There is a column showing the as-filed information and a column showing the as-proposed or total column. The information included in the total columns include the financial impact of all past and proposed environmental facilities. The Company would propose filing monthly schedules only with the total column.

WITNESS: Errol K Wagner

ES FORM 1.00

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CALCULATION OF E(m) and SURCHARGE FACTOR
For the Expense Month of July 2006

	CALCULATION OF E(m) E(m) = CRR - BRR	AS FILED JULY 2006	TOTAL
LINE 1	CRR from ES FORM 3.00	$3,058,984	$4,178,359
LINE 2	Brr from ES FORM 1.10	**2,818,212**	**2,818,212**
LINE 3	E(m) (LINE 1 - LINE 2)	$240,772	$1,360,147
LINE 4	Kentucky Retail Jurisdictional Allocation Factor, from ES FORM 3.30, Schedule of Revenues, LINE 1	64.0%	64.0%
LINE 5	KY Retail E(m) (LINE 3 * LINE 4)	$154,094	$870,494
LINE 6	Over/(Under) Recovery Adjustment from ES FORM 3.30	($187,244)	($187,244)
LINE 7	Net KY Retail E(m) (LINE 5 + LINE 6)	($33,150)	$683,250
	SURCHARGE FACTOR		
LINE 8	Net KY Retail E(m) (Line 7)	($33,150)	$683,250
LINE 9	KY Retail R(m) from ES FORM 3.30	$36,201,227	$36,201,227
LINE 10	Environmental Surchage Factor for Expense Month (Line 8 / LINE 9)	-0.0916%	1.8874%

Effective Date for Billing: ______________________

Submitted By : ______________________

Title : Director Regulatory Services

Date Submitted : ______________________

ES FORM 1.10

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
BASE PERIOD REVENUE REQUIREMENT
For the Expense Month of July 2006

MONTHLY BASE PERIOD REVENUE REQUIREMENT

Billing Month	Base Net Environmental Costs
JANUARY	$2,531,784
FEBRUARY	3,003,995
MARCH	2,845,066
APRIL	2,095,535
MAY	1,514,859
JUNE	1,913,578
JULY	2,818,212
AUGUST	2,342,883
SEPTEMBER	2,852,305
OCTOBER	2,181,975
NOVEMBER	2,598,522
DECEMBER	1,407,969
TOTAL	$28,106,683

ES FORM 3.00

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
For the Expense Month of July 2006

CALCULATION OF CURRENT PERIOD REVENUE REQUIREMENT

LINE NO.	COMPONENTS	AS FILED JULY 2006	TOTAL
	First Component: Associated with Big Sandy Plant		
	((RB KP(C)) (ROR KP(C)/12)) + OE KP(C)		
1	**ES FORM 3.10**, Line 20	$3,180,728	$4,298,297
	Second Component: Associated with Rockport Plant		
	[((RB IM(C)) (ROR IM(C)/12)) + OE IM(C)		
2	**ES FORM 3.20**, Line 12	$4,130	$5,936
	Third Component: Net Proceeds from Emission Allowances Sales AS		
	1) **SO2** - EPA Auction Proceeds received during Expense Month	$0	$0
	2) **SO2** - Net Gain or (Loss) from Allowance Sales, in compliance with the AEP Interim Allowance Agreement, received during Expense Month	$125,874	$125,874
	Total Net Proceeds from SO2 Allowances	$125,874	$125,874
	1) **NOx** - ERC Sales Proceeds, received during Expense Month	$0	$0
	2) **NOx** - EPA Auction Proceeds, received during Expense Month	$0	$0
	3) **NOx** - Net Gain or Loss from NOx Allowances Sales, received during Expense Month	$0	$0
	Total Net Proceeds from NOx Allowances	$0	$0
3	Total Net Gain or (Loss) from Emission Allowance Sales	$125,874	$125,874
4	Total Current Period Revenue Requirement, CRR Record on ES FORM 1.00.	$3,058,984	$4,178,359

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
COSTS ASSOCIATED WITH BIG SANDY

For the Expense Month of July 2006

LINE NO.	COST COMPONENT	AS FILED JULY 2006	AS FILED JULY 2006	TOTAL	TOTAL
	Return on Rate Base :				
1	Utility Plant at Original Cost	$191,352,406		$191,352,406	
2	Less Accumulated Depreciation	($28,081,453)		($28,081,453)	
3	Less Accum. Def. Income Taxes	($30,666,364)		($30,666,364)	
4	Net Utility Plant		$132,604,589		$132,604,589
5	SO2 Emission Allowance Inventory from ES FORM 3.11		$10,586,378		$10,586,378
6	ECR & NOx Emission Allowance Inventory from ES FORM 3.12		$0		$0
7	Cash Working Capital Allowance from ES FORM 3.13, Line11		$127,662		$148,688
8	Total Rate Base		$143,318,629		$143,339,655
9	Weighted Average Cost of Capital - ES FORM 3.15	9.97%		9.97%	
10	Monthly Weighted Avg. Cost of Capital (7)/12		0.83%		0.83%
11	Monthly Return of Rate Base (8) * (10)		$1,189,545		$1,189,719
	Operating Expenses :				
12	Monthly Depreciation Expense		$577,125		$577,125
13	Monthly Catalyst Amortization Expense		$46,030		$46,030
14	Monthly Property Taxes		$18,325		$18,325
15	Monthly Kentucky Air Emissions Fee		$24,732		$24,732
16	Monthly Environmental AEP Pool Capacity Costs from ES FORM 3.14, Page 1 of 11, Column 5, Line 10		$704,880		$1,822,275
17	Non-Fuel O&M Expenses from ES FORM 3.13, Lines 5, 6, 7, 8 & 9		$305,021		$305,021
18	Monthly SO2 Emission Allowance Consumption		$315,070		$315,070
19	Monthly ERC & NOx Emission Allowance Consumption		$0		$0
20	Total Operating Expenses [Line 12 thru Line 19]		$1,991,183		$3,108,578
21	Total Revenue Requirement - Big Sandy Record on ES FORM 3.00, Line 1		$3,180,728		$4,298,297

ES FORM 3.11

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
SO2 EMISSIONS ALLOWANCE INVENTORY

For the Expense Month of July 2006

	(1) Allowance Activity in Month	(2) Cumulative Balance	(3) Dollar Value of Activity	(4) Cumulative Dollar Balance	(5) Weighted Average Cost
BEGINNING INVENTORY		754,608		$4,685,726	$6.209
Additions -					
EPA Allowances	0	298,425	$0	$0	$0.000
Gavin Reallocation	0	51,715	$0	$0	$0.000
P & E Transfers In	0	323,146	$0	$4,236,049	$13.109
Intercompany Purchases	0	20,657	$0	$3,212,441	$155.513
Other (List)	0	413,387	$0	$63,939,192	$154.672
SO2 Emissions Allowance Adjustment	0	4	$0	$0	$0.000
Withdrawals -					
P & E Transfers Out	0	9,038	$0	$775,253	$85.777
Intercompany Sales	0	47,090	$0	$4,598,026	$97.643
Off - System Sales	225	290,141	$13,439	$29,482,827	$101.616
SO2 Emissions Allowance Adjustment	0	0	$0	$0	$0.000
SO2 Emissions Allowances Consumed By Kentucky Power	5,275	379,341	$315,070	$30,630,924	$80.748
ENDING INVENTORY - Record Balance in Column (4) on ES FORM 3.10, Line 5		1,136,332		$10,586,378	$9.316
Expense Month Member Load Ratio for AEP/Kentucky Power					**0.07502**

Columns 1 and 2 -
Record the number of allowances in any transaction (purchase, sale, transfer) which occurred during the Expense Month. Multiple transactions for a given category are to be shown as the total activity for that category during the Expense Month. For each transaction shown in Column 1, update the cumulative balance in Column 2.

Columns 3 and 4 -
For each transaction reflected in Column 1, record the total dollars of the transaction. Multiple transaction for a given category are to be shown as the total dollar amount for that category during the Expense Month. For each transaction shown in Column 3, update the cumulative dollar balance in Column 4. Include transactions that total zero dollars. Record amounts in whole dollars.

Column 5 -
Compute the Weighted Average Cost by dividing the Cumulative Dollar Balance (Co. 4) by the corresponding Cumulative Balance (Col. 2). Perform this calculation for the Beginning Inventory, Ending Inventory and all additions and withdrawals made during the Expense Month. The Weighted Average Cost should be carried out to 3 decimal places.

ES FORM 3.12

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
ECR and NOx EMISSIONS ALLOWANCE INVENTORY

For the Expense Month of July 2006

	(1) Allowance Activity in Month	(2) Cumulative Balance	(3) Dollar Value of Activity	(4) Cumulative Dollar Balance	(5) Weighted Average Cost
BEGINNING INVENTORY		0		$0	0.000
Additions -					
EPA Allowances	0	18,543	$0	$0	
P&E Transfers In	0	0		$0	
Intercompany Purchases	0	0	$0	$0	0.000
Other (List)	0	0	$0	$0	0.000
Withdrawals -					
P & E Transfers Out	0	0	$0	$0	0.000
Intercompany Sales	0	0	$0	$0	0.000
Off - System Sales		1,600	$0	$0	0.000
ERC Consumed By Kentucky Power	0	930	$0	$0	0.000
NOx Consumed By Kentucky Power	736	5,755	$0	$0	0.000
ENDING INVENTORY - Record Balance in Column (4) on ES FORM 3.10, Line 5		10,258		$0	0.000

Columns 1 and 2 -
Record the number of allowances in any transaction (purchase, sale, transfer) which occurred during the Expense Month. Multiple transactions for a given category are to be shown as the total activity for that category during the Expense Month. For each transaction shown in Column 1, update the cumulative balance in Column 2.

Columns 3 and 4 -
For each transaction reflected in Column 1, record the total dollars of the transaction. Multiple transaction for a given category are to be shown as the total dollar amount for that category during the Expense Month. For each transaction shown in Column 3, update the cumulative dollar balance in Column 4. Include transactions that total zero dollars. Record amounts in whole dollars.

Column 5 -
Compute the Weighted Average Cost by dividing the Cumulative Dollar Balance (Co. 4) by the corresponding Cumulative Balance (Col. 2). Perform this calculation for the Beginning Inventory, Ending Inventory and all additions and withdrawals made during the Expense Month. The Weighted Average Cost should be carried out to 3 decimal places.

Note : For any sale or transfer of ERCs or NOx emission allowances, attach to this report documentation showing the currently available market prices for similar ERC or NOx allowances.

Total Early Reduction Credits (ERC)	930
Consumed:	
June 2004	420
July 2004	510
Total Consumed	930
Remaining Early Reduction Credits (ERC)	0

ES FORM 3.13

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT

For the Expense Month of July 2006

LINE NO.	O&M Expenses	AS FILED JULY 2006	TOTAL
1	Monthly Kentucky Air Emissions Fee	$24,732	$24,732
	Total Monthly AEP Pool		
2	Environmental Capacity Costs	$376,470	$544,680
3	Monthly SO2 Allowance Consumption	$315,070	$315,070
4	Monthly Varible Cladding at Big Sandy Unit 1	$0	$0
5	Monthly Urea Consumption at Big Sandy Unit 2	$201,871	$201,871
6	Monthly Catalyst Replacement at Big Sandy Unit 2	$0	$0
7	Monthly ERC & NOx Allowance Consumption	$0	$0
8	Equipment - Associated Operating Expenses	$23,957	$23,957
9	Equipment - Associated Maintenance Expenses	$79,193	$79,193
10	Total Monthly O&M Expenses	$1,021,293	$1,189,503
11	Cash Working Capital Allowance (Line 10 X 1/8)	$127,662	$148,688

Total Cost at Line 11 is to be recorded on ES FORM 3.10, Line 7.

Kentucky Power Company
Environmental Equipment Operation and Maintenance Costs
July 2006

Work Description	Material Costs	Outside Contract Labor	Misc Other Costs	Total Costs
SCR Boiler Outlet Ductwork	$950.80	$71,766.29	$0.00	$72,717.09
SCR Booster Fans	($24.07)	$0.00	$0.00	($24.07)
SCR Ammonia Injection System	$589.50	$0.00	$0.00	$589.50
SCR Acoustic Horns	$350.69	$0.00	$0.00	$350.69
Total SCR July 2006 O & M Expense	**$1,866.92**	**$71,766.29**	**$0.00**	**$73,633.21**
Additional Operator Overtime During The Ozone Season	$0.00	$0.00	$23,956.59	$23,956.59
Emission Testing Required Under Permit -				
Operation	$0.00	$0.00	$0.00	$0.00
Maintenance	$3,022.93	$2,536.99	$0.00	$5,559.92
July 2006 O & M Expenses Filed				**$103,150**

ES FORM 3.14
Page 1 of 11

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
AEP POOL MONTHLY ENVIRONMENTAL CAPACITY COSTS

For the Expense Month of July 2006

Line No. (1)	Cost Component (2)	AS FILED JULY 2006 Ohio Power Company's Environmental Cost to KPCo (3)	AS FILED JULY 2006 Indiana Michigan Power Company's Environmental Cost to KPCo (4)	AS FILED JULY 2006 Total (5)	TOTAL Ohio Power Company's Environmental Cost to KPCo (6)	TOTAL Indiana Michigan Power Company's Environmental Cost to KPCo (7)	Total (8)
1	Amos Unit No. 3 Environmental Cost to Kentucky Power (ES FORM 3.14, Page 3 of 11, Line 22)	$56,070			$300,375		
2	Cardinal Unit No. 1 Environmental Cost to Kentucky Power (ES FORM 3.14, Page 4 of 11, Line 20)	$60,075			$264,330		
3	Gavin Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 5 of 11, Line 25)	$484,605			$492,615		
4	Kammer Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 6 of 11, Line 20)	$4,005			$4,005		
5	Mitchell Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 7 of 11, Line 20)	$12,015			$660,825		
6	Muskingum Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 8 of 11, Line 20)	$68,085			$68,085		
7	Sporn Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 9 of 11, Line 20)	$12,015			$12,015		
8	Rockport Plant Environmental to Kentucky Power (ES FORM 3.14, Page 10 of 11, Column 5, Line 21)		$4,005			$4,005	
9	Tanners Creek Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 11 of 11, Line 20)		$4,005			$16,020	
10	Total AEP Pool Monthly Environmental Capacity Costs to Kentucky Power	$696,870	$8,010	$704,880	$1,802,250	$20,025	$1,822,275

Note: Cost in Column 5, Line 10 is to be recorded on ES FORM 3.10, Line 16.

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
AEP POOL MONTHLY ENVIRONMENTAL CAPACITY COSTS
WORKING CAPTIAL ONLY

For the Expense Month of July 2006

Line No. (1)	Cost Component (2)	AS FILED JULY 2006 Ohio Power Company's (OPCo) Environmental Cost to KPCo (3)	AS FILED JULY 2006 Indiana Michigan Power Company's (I&M) Environmental Cost to KPCo (4)	AS FILED JULY 2006 Total (5)	TOTAL Ohio Power Company's (OPCo) Environmental Cost to KPCo (6)	TOTAL Indiana Michigan Power Company's (I&M) Environmental Cost to KPCo (7)	Total (8)
1	Amos Unit No. 3 Environmental Cost to Kentucky Power (ES FORM 3.14, Page 3 of 11, Line 22)	$140,218			$782,214		
2	Cardinal Unit No. 1 Environmental Cost to Kentucky Power (ES FORM 3.14, Page 4 of 11, Line 20)	$154,250			$995,261		
3	Gavin Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 5 of 11, Line 25)	$8,599,228			$8,599,228		
4	Kammer Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 6 of 11, Line 20)	$18,033			$18,033		
5	Mitchell Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 7 of 11, Line 20)	$21,235			$2,689,666		
6	Muskingum Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 8 of 11, Line 20)	$206,953			$206,953		
7	Sporn Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 9 of 11, Line 20)	$31,495			$31,495		
8	Rockport Plant Environmental to Kentucky Power (ES FORM 3.14, Page 10 of 11, Column 6 / 9, Line 10)		$0			$0	
9	Rockport Plant Environmental to Kentucky Power (ES FORM 3.14, Page 10 of 11, Column 9 / 10, Line 10)		$0			$0	
10	Tanners Creek Plant Environmental Cost to Kentucky Power (ES FORM 3.14, Page 11 of 11, Line 10)		$4,005			$12,500	
11	*Subtotal*	$9,171,412	$4,005		$13,322,850	$12,500	
12	Steam Capacity By Company - OPCo (Column 3) / I&M (Column 4) (kw)	**8,438,000**	**5,064,000**		**8,438,000**	**5,064,000**	
13	Environmental Base ($/kw)	$1.09	$0.00		$1.58	$0.00	
14	Company Surplus Weighting	**86.00%**	**14.00%**		**86.00%**	**14.00%**	
15	Portion of Weighted Average Capacity Rate Attributed to Environmental Fixed O&M Costs	$0.94	$0.00		$1.36	$0.00	
16	Kentucky Power Capacity Deficit (kw)	**400,500**	**400,500**		**400,500**	**400,500**	
17	Fixed O&M Environmental Cost to Kentucky Power	$376,470	$0	$376,470	$544,680	$0	$544,680

Note: Cost in Column 5, Line 17 is to be recorded on ES FORM 3.13, Line 2.

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - AMOS PLANT UNIT NO. 3

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$389,820,000	$89,843,840	$479,663,840
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$5,340,534	$1,230,861	$6,571,395
4	Ohio Power Company's Percentage Ownership - Environmental Investment	100.00%	100.00%	100.00%
5	OPCo's Share of Cost Associated with Amos Unit No. 3 (3) X (4)	$5,340,534	$1,230,861	$6,571,395
	Operations :			
6	Disposal (5010000)	$436,800	$0	$436,800
7	Urea (5020002)	$0	$204,209	$204,209
8	Trona (5020003)	$41,302	$0	$41,302
9	Lime Stone (5020004)	$346,395	$0	$346,395
10	Air Emission Fee	$0	$6,107	$6,107
11	Total Operations (6) + (7) + (8) + (9) + (10)	$824,497	$210,316	$1,034,813
	Maintenance :			
12	Scrubber Maintenance (5120000)	$276,900	$0	$276,900
13	SCR Maintenance (5120000)	$0	$0	$0
14	Total Maintenance (12) + (13)	$276,900	$0	$276,900
15	1/2 of Maintenance (14) * 50%	$138,450	$0	$138,450
16	Fixed O&M (11) + (15)	$962,947	$210,316	$1,173,263
17	Ohio Power Company's Percentage Ownership - O&M Cost	66.67%	66.67%	66.67%
18	OPCo's Share of O&M Cost Associated with Amos Unit No. 3 (16) X (17)	$641,997	$140,218	$782,214
	Total Revenue Requirement,			
19	Cost Associated with Amos Unit No. 3 (5) + (18)	$5,982,531	$1,371,079	$7,353,609
20	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
21	Amos Unit No. 3 Environmental Rate ($/kw)		$0.16	$0.87
22	Ohio Power Surplus Weighing		86.00%	86.00%
23	Portion of Weighted Average Capacity Rate			
	Attributed to Amos Unit No. 3 SCR ($/kw) (21) * (22)		$0.14	$0.75
	Amos Unit No. 3 Costs to Kentucky Power :			
24	Amos Unit No. 3 Portion ($/kw) (23)		$0.14	$0.75
25	Kentucky Power Capacity Deficit (kw)		400,500	400,500
	Amos Unit No. 3 Environmental Cost to Kentucky Power (24) * (25)			
26	(ES FORM 3.14, Page 1 of 10, Line 1)		$56,070	$300,375

ES FORM 3.14
Page 4 of 11

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - CARDINAL UNIT 1

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$301,364,000	$97,260,706	$398,624,706
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$4,128,687	$1,332,472	$5,461,158
	Operations :			
4	Disposal (5010000)	$200,928	$0	$200,928
5	Urea (5020002)	$0	$151,338	$151,338
6	Trona (5020003)	$147,357	$0	$147,357
7	Lime Stone (5020004)	$429,039	$0	$429,039
8	Air Emission Fee	$0	$2,912	$2,912
9	Total Operations (4) + (5) + (6) + (7) + (8)	$777,324	$154,250	$931,574
	Maintenance :			
10	Scrubber Maintenance (5120000)	$127,374	$0	$127,374
11	SCR Maintenance (5120000)	$0	$0	$0
12	Total Maintenance (10) + (11)	$127,374	$0	$127,374
13	1/2 of Maintenance (11) * 50%	$63,687	$0	$63,687
14	Fixed O&M (9) + (13)	$841,011	$154,250	$995,261
	Total Revenue Requirement,			
15	Cost Associated with Cardinal Unit No. 3 (3) + (14)	$4,969,698	$1,486,722	$6,456,419
16	Ohio Power Company's Percentage Ownership		100.00%	100.00%
17	OPCo's Share of Cost Associated with Cardinal Unit No. 1 (15) X (16)		$1,486,722	$6,456,419
18	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
19	Cardinal Unit No. 1 ($/kw)		$0.18	$0.77
20	Ohio Power Surplus Weighing		86.00%	86.00%
21	Portion of Weighted Average Capacity Rate Attributed to Cardinal Unit No. 1 ($/kw) (19) X (20)		$0.15	$0.66
	Cardinal Unit No. 1 Costs to Kentucky Power :			
22	Cardinal Unit No. 1 Portion ($/kw) (21)		$0.15	$0.66
23	Kentucky Power Capacity Deficit (kw)		400,500	400,500
24	Cardinal Unit No. 1 Environmental Cost to Kentucky Power (22) * (23) (ES FORM 3.14, Page 1 of 10, Line 2)		$60,075	$264,330

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - GAVIN PLANT (UNITS 1 & 2)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$9,997,000	$243,404,794	$253,401,794
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$136,959	$3,334,646	$3,471,605
	Operations :			
4	Sludge Disposal (5010000)	$0	$404,594	$404,594
5	Lime (5020000)	$0	$2,620,083	$2,620,083
6	Urea (5020002)	$0	$771,121	$771,121
7	Trona (5020003)	$0	$325,904	$325,904
8	Air Emission Fee	$0	$28,432	$28,432
9	Lease (5070005)	$0	$4,236,232	$4,236,232
10	Total Operations (4) + (5) + (6) + (7) + (8) + (9)	$0	$8,386,366	$8,386,366
	Maintenance :			
11	SCR Maintenance (5120000)	$0	$20,627	$20,627
12	Scrubber Maintenance (5120000)	$0	$405,097	$405,097
13	Total Maintenance (11) + (12)	$0	$425,724	$425,724
14	1/2 of Maintenance (13) * 50%	$0	$212,862	$212,862
15	Fixed O&M (10) + (14)	$0	$8,599,228	$8,599,228
	Total Revenue Requirement,			
16	Cost Associated with Gavin Plant (3) + (15)	$136,959	$11,933,874	$12,070,833
17	Ohio Power Company's Percentage Ownership	100.00%	100.00%	100.00%
18	OPCo's Share of Cost Associated with Gavin Plant (16) X (17)	$136,959	$11,933,874	$12,070,833
19	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
20	Gavin Plant ($/kw)		$1.41	$1.43
21	Ohio Power Surplus Weighing		86.00%	86.00%
22	Portion of Weighted Average Capacity Rate Attributed to Gavin Plant ($/kw) (20) X (21)		$1.21	$1.23
	Gavin Plant Costs to Kentucky Power :			
23	Gavin Plant Portion ($/kw) (22)		$1.21	$1.23
24	Kentucky Power Capacity Deficit (kw)		400,500	400,500
	Gavin Plant Environmental Cost to Kentucky Power (23) * (24)			
25	(ES FORM 3.14, Page 1 of 10, Line 3)		$484,605	$492,615

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - KAMMER PLANT (UNITS 1, 2 & 3)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$0	$7,064,364	$7,064,364
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$0	$96,782	$96,782
	Operations :			
4	Urea (5020002)	$0	$0	$0
5	Trona (5020003)	$0	$0	$0
6	Air Emission Fee	$0	$18,033	$18,033
7	Total Operations (4) + (5) + (6)	$0	$18,033	$18,033
	Maintenance :			
8	SCR Maintenance (5120000)	$0	$0	$0
9	1/2 of Maintenance (8) * 50%	$0	$0	$0
10	Fixed O&M (7) + (9)	$0	$18,033	$18,033
	Total Revenue Requirement,			
11	Cost Associated with Kammer Plant (3) + (10)	$0	$114,815	$114,815
12	Ohio Power Company's Percentage Ownership	100.00%	100.00%	100.00%
13	OPCo's Share of Cost Associated with Kammer Plant (11) X (12)	$0	$114,815	$114,815
14	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
15	Kammer Plant ($/kw)		$0.01	$0.01
16	Ohio Power Surplus Weighing		86.00%	86.00%
17	Portion of Weighted Average Capacity Rate Attributed to Kammer Plant ($/kw) (15) X (16)		$0.01	$0.01
	Kammer Plant Costs to Kentucky Power :			
18	Kammer Plant Portion ($/kw) (17)		$0.01	$0.01
19	Kentucky Power Capacity Deficit (kw)		400,500	400,500
20	Kammer Plant Environmental Cost to Kentucky Power (18) * (19) (ES FORM 3.14, Page 1 of 10, Line 4)		$4,005	$4,005

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - MITCHELL PLANT (UNITS 1 & 2)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$967,634,000	$19,443,483	$987,077,483
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$13,256,586	$266,376	$13,522,962
	Operations :			
4	Disposal (5010000)	$537,600	$0	$537,600
5	Urea (5020002)	$749,064	$0	$749,064
6	Trona (5020003)	$127,878	$0	$127,878
7	Lime Stone (5020004)	$1,083,489	$0	$1,083,489
8	Air Emission Fee	$0	$21,235	$21,235
9	Total Operations (4) + (5) + (6) + (7) + (+8)	$2,498,031	$21,235	$2,519,266
	Maintenance :			
10	Scrubber Maintenance (5120000)	$340,800	$0	$340,800
11	SCR Maintenance (5120000)	$0	$0	$0
12	Total Maintenance (10) + (11)	$340,800	$0	$340,800
13	1/2 of Maintenance (12) * 50%	$170,400	$0	$170,400
14	Fixed O&M (9) + (13)	$2,668,431	$21,235	$2,689,666
	Total Revenue Requirement,			
15	Cost Associated with Mitchell Plant (3) + (14)	$15,925,017	$287,611	$16,212,628
16	Ohio Power Company's Percentage Ownership	100.00%	100.00%	100.00%
17	OPCo's Share of Cost Associated with Mitchell Plant (15) X (16)	$15,925,017	$287,611	$16,212,628
18	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
19	Mitchell Plant ($/kw)		$0.03	$1.92
20	Ohio Power Surplus Weighing		86.00%	86.00%
21	Portion of Weighted Average Capacity Rate Attributed to Mitchell Plant ($/kw) (19) X (20)		$0.03	$1.65
	Mitchell Plant Costs to Kentucky Power :			
22	Mitchell Plant Portion ($/kw) (21)		$0.03	$1.65
23	Kentucky Power Capacity Deficit (kw)		400,500	400,500
24	Mitchell Plant Environmental Cost to Kentucky Power (22) * (23) (ES FORM 3.14, Page 1 of 10, Line 5)		$12,015	$660,825

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - MUSKINGUM PLANT (UNITS 1, 2, 3 , 4 & 5)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$0	$106,143,602	$106,143,602
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$0	$1,454,167	$1,454,167
	Operations :			
4	Urea (5020002)	$0	$179,257	$179,257
5	Trona (5020003)	$0	$0	$0
6	Air Emission Fee	$0	$27,696	$27,696
7	Total Operations (4) + (5) + (6)	$0	$206,953	$206,953
	Maintenance :			
8	SCR Maintenance (5120000)	$0	$0	$0
9	1/2 of Maintenance (8) * 50%	$0	$0	$0
10	Fixed O&M (7) + (9)	$0	$206,953	$206,953
	Total Revenue Requirement,			
11	Cost Associated with Muskingum Plant (3) + (10)	$0	$1,661,120	$1,661,120
12	Ohio Power Company's Percentage Ownership	100.00%	100.00%	100.00%
13	OPCo's Share of Cost Associated with Muskingum Plant (11) X (12)	$0	$1,661,120	$1,661,120
14	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
15	Muskingum Plant ($/kw)		$0.20	$0.20
16	Ohio Power Surplus Weighing		86.00%	86.00%
17	Portion of Weighted Average Capacity Rate Attributed to Muskingum Plant ($/kw) (15) X (16)		$0.17	$0.17
	Muskingum Plant Costs to Kentucky Power :			
18	Muskingum Plant Portion ($/kw) (17)		$0.17	$0.17
19	Kentucky Power Capacity Deficit (kw)		400,500	400,500
20	Muskingum Plant Environmental Cost to Kentucky Power (18) * (19) (ES FORM 3.14, Page 1 of 10, Line 6)		$68,085	$68,085

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
OHIO POWER COMPANY (OPCo) - SPORN PLANT (UNITS 2, 3, 4 & 5)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$6,546,000	$15,246,415	$21,792,415
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$89,680	$208,876	$298,556
	Operations :			
4	Urea (5020002)	$0	$18,127	$18,127
5	Trona (5020003)	$0	$0	$0
6	Air Emission Fee	$0	$13,368	$13,368
7	Total Operations (4) + (5) + (6)	$0	$31,495	$31,495
	Maintenance :			
8	SCR Maintenance (5120000)	$0	$0	$0
9	1/2 of Maintenance (8) * 50%	$0	$0	$0
10	Fixed O&M (7) + (9)	$0	$31,495	$31,495
	Total Revenue Requirement,			
11	Cost Associated with Sporn Plant (3) + (10)	$89,680	$240,371	$330,051
12	Ohio Power Company's Percentage Ownership	100.00%	100.00%	100.00%
13	OPCo's Share of Cost Associated with Sporn Plant (11) X (12)	$89,680	$240,371	$330,051
14	Ohio Power Company Steam Capacity (kw)		8,438,000	8,438,000
15	Sporn Plant ($/kw)		$0.03	$0.04
16	Ohio Power Surplus Weighing		86.00%	86.00%
17	Portion of Weighted Average Capacity Rate Attributed to Sporn Plant ($/kw) (15) X (16)		$0.03	$0.03
	Sporn Plant Costs to Kentucky Power :			
18	SpornGavin Plant Portion ($/kw) (17)		$0.03	$0.03
19	Kentucky Power Capacity Deficit (kw)		400,500	400,500
20	Sporn Plant Environmental Cost to Kentucky Power (18) * (19) (ES FORM 3.14, Page 1 of 10, Line 7)		$12,015	$12,015

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
INDIANA MICHGAN POWER COMPANY (I&M) - ROCKPORT PLANT (UNITS 1 & 2)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN UNIT 1 AMOUNTS	2006 PLAN UNIT 2 AMOUNTS	TOTAL	AS FILED JULY 2006 PLAN UNIT 1 AMOUNTS	AS FILED JULY 2006 P PLAN UNIT 2 AMOUNTS	TOTAL	TOTAL UNIT 1 AMOUNTS	TOTAL UNIT 2 AMOUNTS	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Utility Plant at Original Cost	$499,000	$499,000		$10,544,676	$16,714,682		$11,043,676	$17,213,682	
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%		1.37%	1.37%		1.37%	1.37%	
3	Total Rate Base	$6,836	$6,836		$144,462	$228,991		$151,298	$235,827	
	Operations :									
4	Urea (5020002)	$0	$0		$0	$0		$0	$0	
5	Trona (5020003)	$0	$0		$0	$0		$0	$0	
6	Air Emission Fee	$0	$0		$0	$0		$0	$0	
7	Total Operations (4) + (5) + (6)	$0	$0		$0	$0		$0	$0	
	Maintenance :									
8	SCR Maintenance (5120000)	$0	$0		$0	$0		$0	$0	
9	1/2 of Maintenance (8) * 50%	$0	$0		$0	$0		$0	$0	
10	Fixed O&M (7) + (10)	$0	$0		$0	$0		$0	$0	
	Total Revenue Requirement,									
11	Cost Associated with Rockport Plant (3) + (10)	$6,836	$6,836		$144,462	$228,991		$151,298	$235,827	
12	Indiana Michigan Power Company's Percentage Ownership	85.00%	65.08%		85.00%	65.08%		85.00%	65.08%	
13	I&M's Share of Cost Associated with Rockport Plant (11) X (12)	$5,811	$4,449		$122,793	$149,027		$128,603	$153,476	
14	Total Rockport Units 1 & 2			$10,260			$271,820			$282,079
15	Indiana Michigan Power Company Steam Capacity (kw)						5,064,000			5,064,000
16	Rockport Plant ($/kw) (14) / (15)						$0.05			$0.06
	Kentucky Power Portion of Rockport Plant /									
17	Indiana Michigan Power Surplus Weighing						14.00%			14.00%
18	Portion of Weighted Average Capacity Rate									
	Attributed to Rockport Plant ($/kw) (16) X (17)						$0.01			$0.01
	Rockport Plant Costs to Kentucky Power :									
19	Rockport Plant Portion ($/kw) (18)						$0.01			$0.01
20	Kentucky Power Capacity Deficit (kw)						400,500			400,500
	Rockport Units 1 & 2 Environmental to Kentucky Power (19) * (20)									
21	(ES FORM 3.14, Page 1 of 10, Line 8)						$4,005			$4,005

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
INDIANA MICHGAN POWER COMPANY (I&M) - TANNERS CREEK (UNITS 1, 2, 3 & 4)

For the Expense Month of July 2006

LINE NO.	COST	2006 PLAN	AS FILED JULY 2006	TOTAL
1	Utility Plant at Original Cost	$90,637,000	$15,810,530	$106,447,530
2	Member Primary Capacity Investment Rate (16.44% / 12)	1.37%	1.37%	1.37%
3	Total Rate Base	$1,241,727	$216,604	$1,458,331
	Operations :			
4	Urea (5020002)	$0	$0	$0
5	Trona (5020003)	$0	$0	$0
6	Air Emission Fee	$0	$12,500	$12,500
7	Total Operations (4) + (5) + (6)	$0	$12,500	$12,500
	Maintenance :			
8	SCR Maintenance (5120000)	$0	$0	$0
9	1/2 of Maintenance (8) * 50%	$0	$0	$0
10	Fixed O&M (7) + (9)	$0	$12,500	$12,500
	Total Revenue Requirement,			
11	Cost Associated with Tanners Creek Plant (3) + (10)	$1,241,727	$229,104	$1,470,831
12	Indiana Michigan Power Company's Percentage Ownership	100.00%	100.00%	100.00%
13	I&M's Share of Cost Associated with Tanners Creek Plant (11) X (12)	$1,241,727	$229,104	$1,470,831
14	Indiana Michigan Power Company Steam Capacity (kw)		5,064,000	5,064,000
15	Tanners Creek Plant ($/kw)		$0.05	$0.29
16	Indiana Michigan Power Surplus Weighing		14.00%	14.00%
17	Portion of Weighted Average Capacity Rate Attributed to Rockport Plant ($/kw) (15) X (16)		$0.01	$0.04
	Tanners Creek Plant Costs to Kentucky Power :			
18	Tanners Creek Plant Portion ($/kw) (17)		$0.01	$0.04
19	Kentucky Power Capacity Deficit (kw)		400,500	400,500
20	Tanners Creek Plant Environmental Cost to Kentucky Power (18) * (19) (ES FORM 3.14, Page 1 of 10, Line 9)		$4,005	$16,020

ES FORM 3.15

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
BIG SANDY PLANT COST OF CAPITAL

For the Expense Month of July 2006

LINE NO.	Component	Balances	Cap. Structure	Cost Rates		WACC (Net of Tax)	GRCF		WACC (PRE-TAX)
		As of 06/30/2005							
1	L/T DEBT	$487,716,122	57.43%	5.70%		3.27%			3.27%
2	S/T DEBT	$0	0.00%	3.34%		0.00%			0.00%
3	ACCTS REC FINANCING	$30,139,598	3.55%	2.99%		0.11%			0.11%
4	C EQUITY	$331,354,481	39.02%	**10.50%**	1/	4.10%	1.6073	2/	6.59%
5	TOTAL	**$849,210,201**	**100.00%**			**7.48%**			**9.97%**

WACC = Weighted Average Cost of Capital

1/ Rate of Return on Common Equity per Case No. 2005 - 00341

2/ Gross Revenue Conversion Factor (GRCF) Calculation:
Appendix C Case No. 2005-00341 dated - March 14, 2006

1	OPERATING REVENUE	100.0000
2	UNCOLLECTIBLE ACCOUNTS EXPENSE (0.47%)	0.4700
3	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	99.5300
4	STATE INCOME TAX EXPENSE, NET OF 199 DEDUCTION (SEE BELOW)	6.0450
5	FEDERAL TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	93.4850
6	199 DEDUCTION PHASE-IN	2.8050
7	FEDERAL TAXABLE PRODUCTION INCOME	90.6800
8	FEDERAL INCOME TAX EXPENSE AFTER 199 DEDUCTION (35%)	31.7380
9	AFTER-TAX PRODUCTION INCOME	58.9420
10	GROSS-UP FACTOR FOR PRODUCTION INCOME:	
11	AFTER-TAX PRODUCTION INCOME	58.9420
12	199 DEDUCTION PHASE-IN	2.8050
13	UNCOLLECTIBLE ACCOUNTS EXPENSE	0.4700
14	TOTAL GROSS-UP FACTOR FOR PRODUCTION INCOME (ROUNDED)	62.2170
15	BLENDED FEDERAL AND STATE TAX RATE:	
16	FEDERAL (LINE 8)	31.7380
17	STATE (LINE 4)	6.0450
18	BLENDED TAX RATE	37.7830
19	GROSS REVENUE CONVERSION FACTOR (100.0000 / Line 14)	1.6073

STATE INCOME TAX CALCULATION:

1	PRE-TAX PRODUCTION INCOME	100.0000
2	COLLECTIBLE ACCOUNTS EXPENSE (0.20%)	0.4700
3	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	99.5300
4	LESS: STATE 199 DEDUCTION	2.8050
5	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	96.7250
6	STATE INCOME TAX RATE	6.2500
7	STATE INCOME TAX EXPENSE (LINE 5 X LINE 6)	6.0450

The WACC (PRE - TAX) value on Line 5 is to be recorded on ES FORM 3.10, Line 9.

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
COSTS ASSOCIATED WITH ROCKPORT

For the Expense Month of July 2006

LINE NO.	COST COMPONENT		2006 Plan Unit No. 1	2006 Plan Unit No. 2	2006 Plan Total Units 1 & 2	**As Filed July 2006 Rockport Plant Common**	Total Rockport Plant Common	Total AEGCo Low NOx Burners	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Return on Rate Base :								
	Rockport Plant Continous Environmental Monitoring System (CEMS)								
1	Installed Cost					$1,776,759	$1,776,759		
2	AEGCo Low NOx Burners (LNB) Installed Cost							$0	
3	Rockport Plant Landfill		$499,000	$499,000			$998,000		
4	Less Accumulated Depreciation		$0	$0		($574,057)	($574,057)	$0	
5	Less Accum. Def. Income Taxes		$0	$0		($127,333)	($127,333)	$0	
6	Total Rate Base		$499,000	$499,000	$998,000	$1,075,369	$2,073,369	$0	
7	Weighted Average Cost of Capital - ES FORM 3.21	10.9555%							
8	Monthly Weighted Avg. Cost of Capital (LINE 7 / 12)				0.9130%	0.9130%	0.9130%	0.9130%	
9	Monthly Return of Rate Base (Line 6 * Line 8)				$9,112	$9,818	$18,930	$0	
	Operating Expenses :								
10	Monthly Depreciation Expense		$1,464	$1,464		$5,212	$8,140	$0	
11	Monthly Indiana Air Emissions Fee		$0	$0		$12,500	$12,500	$0	
12	Total Operating Expenses (Line 10 + Line 11)		$1,464	$1,464	$2,928	$17,712	$20,640	$0	
13	Total Revenue Requirement, Cost Associated with Rockport Plant CEMS and LNB (Line 9 + Line 12)				$12,040	$27,530	$39,570	$0	
14	*Kentucky Power's Portion of Rockport's CEMS and Landfill (Line 13 * 15%)*					**$4,130**	**$5,936**		
15	Kentucky Power's Portion of AEGCo's LNB (Line 13 * 30%)							**$0**	
16	Kentucky Power's Portion of Rockport Plant's Total Revenue Requirement. (Column 8, Line 14 + Column 11, Line 15) **Note:** Cost In Column 11, Line 16 is to be Recorded on ES FORM 3.00 Line 2								**$5,936**

With each monthly filing, attach a schedule similar to Exhibit EKW-2, page 11 of 11 (Wagner Direct Testimony in Case No. 96-489), showing the calculation of the Weighted Average Cost of Capital. These calculations should reflect the provisions of the Rockport Unit Power Agreement, and be as of the Current Expense Month.

ES FORM 3.21

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
ROCKPORT UNIT POWER AGREEMENT COST OF CAPITAL

For the Expense Month of July 2006

LINE NO.	Component	Balances	Cap. Structures	Cost Rates		WACC (NET OF TAX)	GRCF		WACC (PRE - TAX)
		As of 07/31/2006							
1	L/T DEBT	44,832,773	33.5997%	4.6595%		1.5656%			1.5656%
2	S/T DEBT	36,988,978	27.7212%	5.3450%		1.4817%			1.4817%
	CAPITALIZATION								
3	OFFSETS	0	0.0000%	4.9694%		0.0000%			0.0000%
4	DEBT								
5	C EQUITY	51,610,433	38.6791%	**12.1600%**	1/	4.7034%	1.681379	2/	7.9082%
6	TOTAL	133,432,184	100.0000%			7.7507%			10.9555%
		=========	=========			=========			=========

WACC = Weighted Average Cost of Capital
1/ Cost Rates per the Provisions of the Rockport Unit Power Agreement

2/ Gross Revenue Conversion Factor (GRCF) Calculation:

1	OPERATING REVENUE	100.00
2	LESS: INDIANA ADJUSTED GROSS INCOME	
3	(LINE 1 X .085)	8.500
4	INCOME BEFORE FED INC TAX	91.500
5	LESS: FEDERAL INCOME TAX	
6	(LINE 4 X .35)	32.025
7	OPERATING INCOME PERCENTAGE	59.475
8	GROSS REVENUE CONVERSION	
9	FACTOR (100% / LINE 7)	1.681379

The WACC (PRE - TAX) value on Line 6 is to be recorded on ES FORM 3.20, Line 5.

ES FORM 3.30

KENTUCKY POWER COMPANY - ENVIRONMENTAL SURCHARGE REPORT
CURRENT PERIOD REVENUE REQUIREMENT
MONTHLY REVENUES, JURISDICTIONAL ALLOCATION FACTOR, and OVER/(UNDER) RECOVERY ADJUSTMENT

For the Expense Month of July 2006

SCHEDULE OF MONTHLY REVENUES

Line No.	Description	Monthly Revenues	Percentage of Total Revenues
1	Kentucky Retail Revenues	$36,201,227	**64.0%**
2	FERC Wholesale Revenues	$355,328	0.6%
3	Associated Utilities Revenues	$5,153,092	9.1%
4	Non-Assoc. Utilities Revenues	$14,910,575	26.3%
5	Total Revenues for Surcharges Purposes	$56,620,222	100.0%
6	Non-Physical Revenues for Month	$1,147,168	
7	Total Revenues for Month	$57,767,390	

The Kentucky Retail Monthly Revenues and Percentage of Total Revenues (Line 1) are to be recorded on ES FORM 1.00, Lines 9 and 4. The Percentage of Kentucky Retail Revenues to the Total Revenues for the Expense Month will be the Kentucky Retail Jurisdictional Allocation Factor.

OVER/(UNDER) RECOVERY ADJUSTMENT

Line No.	Description	Amounts
1	Kentucky Retail Surcharge Factor for **May 2006**	2.6225%
2	Kentucky Retail Revenues for Current Expense Month	$35,344,519
3	Surcharge Collected (1) * (2)	$926,910
4	Surcharge Amount To Be Collected	$739,666
5	Over/(Under) Recovery (3) - (4) = (5)	$187,244

The Over/(Under) Recovery amount is to be recorded on ES FORM 1.00, LINE 6.

NOTE : The sign on LINE 5 of ES FORM 3.30 will be changed on LINE 6 of ES FORM 1.00 in order to properly adjust the collection of the current month's expense.