COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF AN AMENDED COMPLIANCE PLAN FOR PURPOSES OF RECOVERING ADDITIONAL COSTS OF POLLUTION CONTROL FACILITIES AND TO AMEND ITS ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF	)	CASE NO. 2005-00068

BRIEF OF KENTUCKY POWER COMPANY

I. INTRODUCTION

Kentucky Power Company ("KPCo" or the "Company") seeks recovery in this case of certain environmental costs required by the Clean Air Act as Amended. The Company seeks recovery of these costs pursuant to KRS 278.183, which provides that a utility is entitled to current recovery (via a surcharge) of costs incurred for compliance with the Federal Clean Air Act, as amended, ("CAAA") and those federal, state or local environmental requirements which apply to coal combustion and by-products from facilities used to generate electricity from coal. *See* KRS 278.183(1). The statute requires the utility to present an environmental compliance plan to the Commission before imposing the surcharge. KRS 278.183(2). The Commission must consider the plan and the proposed rate surcharge, and approve them if it finds the plan and rate surcharge to be reasonable and cost-effective *Id.*

This is KPCo's third request for approval of recovery of environmental costs. The Company has made changes to its original plan as the requirements of the CAAA have been applied. The particular provisions of the CAAA that required the majority of the Company's recoverable environmental costs relate to the Nitrogen Oxide (NO_x) and Sulfur Dioxide (SO_2)

emission reduction standards for coal-fired power plants that have been phased in over the last several years.

Kentucky Power is a subsidiary of American Electric Power and a member of the AEP Pool. The AEP Pool was created by the FERC–approved AEP Interconnection Agreement ("Pool Agreement" or "Interconnection Agreement"), which allows the members of the Pool to share capacity and the expenses associated with that shared capacity through FERC–approved rates. As will be explained below, Kentucky Power does not own sufficient generating capacity to supply its customers the power they need during peak demand periods. Consequently, Kentucky Power is a deficit member of the AEP Pool and is assigned capacity from its sister AEP companies that have more power capacity than the system's average. The rates paid by Kentucky Power for the capacity received from the AEP surplus companies under the Pool Agreement include charges associated with environmental facilities installed at the generating plants of the surplus companies. Kentucky Power also receives power from and owns an interest in the Rockport generating plants located in Indiana pursuant to a separate FERC–approved agreement, the Unit Power Agreement.

The costs being sought in this proceeding pursuant to the Company's Second Amended Plan are environmental costs incurred by Kentucky Power pursuant to the AEP Interconnection Agreement and the Rockport Unit Power Agreement for environmental compliance.

II. BACKGROUND

A. The AEP Pool

The AEP Pool consists of five operating utilities that are subsidiaries of American Electric Power Company, Inc. The members are KPCo, Appalachian Power Company ("APCo"), Columbus Southern Power Company ("CSP"), Indiana Michigan Power Company("I&M"), and Ohio Power Company ("OPCo"). While each company has title to its own generating facilities, the System is designed, built and operated on an integrated basis. This approach has allowed the AEP System to minimize capacity costs by allowing for larger, more cost–effective units to be constructed, and by insuring cost-effective operation.

Each member's obligations are defined by the Interconnection Agreement. As explained in detail in the testimony of Errol Wagner, the Interconnection Agreement requires each operating company to provide adequate generating facilities or other sources to meet its internal firm load requirement. Wagner Direct Testimony ("EKW") at p. 4. Kentucky Power, for example owns two generating units located at Louisa Kentucky, Big Sandy Unit 1 (260 MW) and Big Sandy Unit 2 (800 MW). Additionally, Kentucky Power has entered into a Unit Power Agreement with AEGCo which entitles KPCo to a share of the generating capacity of the Rockport units owned, in part, or leased by AEGCo. This arrangement gives KPCo an additional 390 MW of capacity. Thus, KPCo's total capacity reserve equals 1450 MW. This amount is significantly less (some 235 MW) than the Company's internal peak demand for 2005 of 1685 MW. Thus, KPCo must rely on the AEP System to meet the demand needs of its customers.

The Interconnection Agreement allows KPCo to meet its demand requirements by relying on the AEP Pool. The Agreement allocates the total AEP System capacity to each member company on the basis of each member company's highest non-coincident peak demand in the preceding twelve month period. The ratio of a member's highest preceding twelve-month non-coincident peak to the total system peak is referred to as the Member Load Ratio ("MLR") for each company. Each member is responsible for its MLR share of the total system capacity. This is called the member's primary capacity reservation and is calculated by multiplying the member's MLR times the total system capacity. If a member's primary capacity reservation exceeds its installed capacity, the member is a deficit member and is required to make up its shortfall by paying the surplus members a carrying charge based on the average embedded cost of capacity of the surplus companies. Conversely, if a member's primary capacity reservation is less than its installed capacity, it is a surplus member.

Because a member's primary capacity reservation is determined by multiplying the member's MLR times the total system capacity, the total capacity surplus in any given month will always equal the total capacity deficit for that month. The Capacity Settlement Charge paid by the deficit companies is a means of equalizing the members' responsibility for the system's installed capacity. Without such a mechanism, Kentucky Power would have to either build new generating facilities (including environmental equipment) at great expense, or purchase power on the open market as needed, resulting in unacceptable risk as well as increased expense.

B. <u>The Clean Air Act Amendments of 1990</u>

In the summer of 1989 the first President Bush proposed sweeping amendments to the Clean Air Act. These changes were enacted by Congress in 1990. 42 U.S.C. §§ 7401 et seq. Title IV of the 1990 Clean Air Act Amendments established a new program placing restrictions on the emission of SO_2 and NO_x (compounds that are considered precursors to acid rain) from electric utilities' generating plants. The Clean Air Act as amended required utilities to reduce SO_2 emissions by 10 million tons from the 1980 levels. Clean Air Act ("CAA") § 401(b). The reduction was implemented in two stages, Phase I and Phase II. CAA §§ 404, 405. Phase I began on January 1, 1995 and required certain large coal-fired utilities to make reductions in SO_2 emissions. Phase II began on January 1, 2000. In Phase II, the Phase I units were required to make further reductions in SO_2 emissions; and the remaining affected utilities were given limits designed to cap annual utility SO_2 emissions at approximately 8.95 million tons. CAA §§ 403(a), 404.

The Clean Air Act as amended also provided for a market-based system of "allowances" that entitled the allowance holder to emit one ton of SO_2 in a given year. CAA § 405. The Environmental Protection Agency ("EPA") allocates a finite number of allowances per year. If a utility's actual emissions exceed its allocated allowances, it must take steps to reduce the emissions or purchase additional allowances from utilities whose actual emissions were less than the allowances allocated to them. Utilities that installed SO_2 scrubbers or complied early were awarded additional allowances.

Title IV also requires a reduction in NO_x emissions by approximately 2 million tons from 1980 levels. CAA § 407. Again, the Act provided for two phases. The first phase required reductions from certain coal-fired plants through the use of low–NO_x burners. For Phase II, the Act provides that EPA must establish allowable emission rates for NO_x emissions from coal-fired electric utility boilers. *Id.* EPA has promulgated two rules governing NO_x emissions. The NO_x SIP Call Rule requires certain states, including Kentucky, to amend their State Implementation Plans to reduce NO_x emissions during the summer ozone season. (63 FR 5736, October 27, 1998). The Section 126 Rule, promulgated in response to a petition by eighteen northeastern states, requires NO_x reductions from upwind States. (64 FR 28259, May 25, 1999 and 65 FR 2674, January 18, 2000).

The NO_x rules require reductions at all of AEP's coal-fired plants. Under Phase I, AEP coal-fired plants reduced NO_x emissions by approximately 30%. Under the Section 126 and NO_x SIP Call Rules, additional reductions of approximately 75% were required across the AEP System. (The required reduction at Big Sandy was 78%.) Thus large reductions in NO_x emissions were required across the AEP System. KPCo Response to Commission Staff 2nd Set Data Request, p. 20 of 79.

C. KRS 278.183

One way in which utilities could reduce SO_2 and NO_x emissions to comply with Title IV of the CAAAs would be to switch to cleaner fuels, either lower sulfur coal or gas. In recognition of the deleterious effect such actions could have on the Kentucky coal market, in 1992 the Kentucky Legislature enacted SB 341, i.e. KRS 278.183, to encourage the use of Kentucky coal by utilities serving the Commonwealth.

The Legislature, in KRS 278.183(1), therefore, provided that "a utility shall be entitled to the current recovery of its costs of complying with the federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by products from facilities utilized for production of energy from coal …." As Kentucky Power has incurred costs in complying with the CAAA, the Company has filed a compliance plan with this Commission and petitioned for recovery and approval of a surcharge for its costs.

D. Kentucky Power's Previous Surcharge Filings

Kentucky Power filed its first environmental surcharge case in 1996. The components of the 1996 plan included, inter alia, low NO_x burners for Big Sandy 2; Kentucky Power's portion of the cost of scrubbers installed at the Gavin Plant owned by Ohio Power Company (as reflected in the capacity charges KPCo pays to Ohio Power under the Interconnection Agreement); purchased SO_2 allowances; and continuous emission monitors (CEM's) and fees for the Rockport plant. This original filing included, therefore, not only direct costs borne by Kentucky Power for controls on the Big Sandy Plant, but also included environmental costs borne by Kentucky Power as a result of its membership in the AEP System and its participation in three FERC–approved agreements: the Interconnection Agreement and the Rockport Unit Power Agreement, discussed in detail above, as well as the Interim Allowance Agreement (that governs the System's allocation and handling of SO_2 allowances). In its order in the 1996 case, the

Commission approved the recovery of the components of the KPCo plan covering costs incurred through the FERC–approved agreements for environmental controls.

In 2002, Kentucky Power filed a second environmental surcharge case and an Amended Plan. *See* Case No. 2002-00169. This filing reflected the new CAAA requirements to place NO_x controls on the Big Sandy units. As a part of this filing (and the preceding Certificate of Need case, Case No. 2001-00093), Kentucky Power provided detailed testimony concerning the manner in which the AEP System was determining the appropriate (and cost-effective) means for compliance with the SO_2 and NO_x requirements of the CAAA. The Company's witness, Michael Durner, explained that AEP uses a production cost model to provide data for an optimization analysis which selects technologies using a least incremental reduction cost method. (The pertinent portions of this testimony and accompanying report have been provided in this case in response to data requests. *See* KPCo Response to Commission Staff Second Set Data Request, pp. 16-17 and 26-40 of 79.) The optimization analysis demonstrated that in "order to reduce System emissions by the required 75%, a significant fraction of the fleet [would] require additional NO_x emission controls." *Id.*, p. 36 of 70. Selective Catalytic Reduction (SCR) must be placed on several System units because it is the only available control technology available that can achieve the required level of NO_x removal. *Id.*

In addition to the detailed analysis provided by the AEP staff in the Company's second surcharge case, the Company provided the testimony and report of an independent outside consultant, Stone & Webster. Stone & Webster reviewed the AEP optimization process and compared the costs for the SCR at Big Sandy to industry experience. They concluded that the AEP SCR costs compared favorably to their SCR benchmark costs. KPCo Response to Commission Staff 3rd Set Data Request, Item No. 2.

The current filing is the third environmental surcharge for the Company and reflects Kentucky Power's MLR share of the on-going compliance requirements for the surplus companies in the AEP System. Now that many of the NO_x and SO_2 controls are in place for the System, Kentucky Power has determined the impact of the CAAA projects at its sister utilities on the Company's capacity equalization charge under the Interconnection Agreement. KPCo has also looked at the additional CAAA environmental project costs it is incurring for the Rockport Units under the Unit Power Agreement. The costs that are being incurred by KPCo for these environmental projects through the FERC–approved Agreements are being sought in this proceeding. The projects are listed along with the applicable CAAA requirement in Exhibit JMM-1. *See* Attachment 1 hereto. The types of environmental facilities at issue are low NO_x burners, over-fire air NO_x control systems, water injection NO_x control systems, and selective catalytic reduction (SCR) systems. McManus Direct Testimony ("JMM") at p. 5. The generating plants involved are those owned, in whole or in part, by the two surplus companies, *i.e.* OPCo's John E. Amos Plant, Cardinal Plant, General James M. Gavin Plant, Mitchell Plant, Kammer Plant, Muskingum River Plant, and the Phillip Sporn Plant and I&M's Rockport Plant and Tanners Creek Plant. *Id.* As noted earlier, these costs are being incurred by KPCo because the Company is relying upon the AEP Pool, and the capacity of these surplus companies (including investment activity with CAAA compliance) to meet the needs of the Company's retail customers.

III. ARGUMENT

A. Kentucky Power is entitled to current recovery of the environmental compliance costs set forth in the Company's Second Amended Plan.

The surcharge statute provides that when a utility requests approval of an environmental compliance plan and a rate surcharge, a hearing shall be conducted to "[c]onsider and approve the plan and rate surcharge if the Commission finds the plan and rate surcharge reasonable and cost–effective for compliance with the applicable environmental requirements set forth in subsection (1) of this section." Thus, the Company must demonstrate (1) that the requested costs are being incurred for compliance with the applicable environmental requirements (the CAAAs in this case); and (2) that the plan and rate surcharge are reasonable and cost–effective for such compliance.

The Company presented the testimony of John McManus, a registered professional engineer, to demonstrate that the costs at issue are being incurred for compliance with the CAAAs. Mr. McManus is the Vice President of the Environmental Services Division of the American Electric Power Service Corporation ("AEPSC"). He is responsible for oversight of environmental support for all AEP generation and energy delivery facilities. He is also the AEP companies' Designated Representative on Title IV Acid Rain Program matters and the listed NO_x Authorized Account Representative on NO_x SIP Call Program matters. As such, he participates directly in the development of environmental compliance plans for the AEP companies' facilities, certifies compliance with the Acid Rain and NO_x SIP Call programs, and is the person legally authorized to represent the facilities in Title IV and NO_x SIP Call matters. JMM at pp. 1-3. Mr. McManus described the types of controls available and the actions undertaken at each of the surplus companies' generating facilities in order to comply with the NO_x and SO_2 reduction requirements and other requirements of the CAAA. *Id.* at pp. 3-12. He further described which provisions of CAAA are applicable to each unit and the cost of each action taken. *Id.* at pp. 12-14 and JMM Exhibit 1.

Mr. McManus also described how AEP has taken advantage of the flexibility provisions of the NO_x SIP Call regulation to allow progressive implementation of control equipment.

Because of the depth of reductions required by the regulation, AEP's NO_x compliance plan calls for installation of SCRs on 11 generating units representing 10,385 MW of generating capacity, an enormous and complex construction undertaking. *Id.* at 14.

The Company also presented the testimony of Errol Wagner. Mr. Wagner, a Certified Public Accountant, is the Director of Regulatory Services for KPCo. He has responsibility for all rate and regulatory matters affecting the Company. EKW at p. 1. Mr. Wagner presented the annual cost the Company expects to incur as a result of the environmental facilities added to the Company's environmental plan in the Second Amended Plan. *Id.* at p. 2. By way of background, Mr. Wagner explained how the AEP Interconnection Agreement works and how the Rockport Unit Power Agreement works. He explained, for instance, that because Kentucky Power is a deficit Company, i.e. it does not have enough capacity (through ownership or Unit Power Agreements) to meet its firm load requirements, it relies upon the generating facilities of the AEP surplus companies to meet some of its generating needs. He further explained that the relationship between the deficit and surplus companies is governed by the FERC–approved Interconnection Agreement. Under that Agreement, the deficit companies must pay a capacity equalization charge to compensate the surplus companies for their investment in the surplus facilities, including the environmental controls placed on those facilities for compliance with the CAAA. *Id.* at pp. 4-8. Mr. Wagner provided exhibits illustrating how Kentucky Power's annual charge associated with the environmental facilities of the surplus companies is determined. EKW Exhibit–4.

Mr. Wagner also explained the nature of KPCo's interest in the Rockport Units under the Rockport Unit Power Agreement and how a portion of the cost of the Low NO_x Burners for Rockport's Units 1 and 2 will flow through the Unit Power Agreement to Kentucky Power while the remaining portion borne by Kentucky Power flows through the Interconnection Agreement. EKW at pp. 8–12 and EKW Exhibit–12. He further explained that the Company is not requesting a rate of return on capital expenditures of the surplus companies and that the estimated effect of the requested surcharge is an increase to retail customers of approximately 0.61% (an annual increase of approximately $3.84 for a residential customer averaging 1,000 kWh per month). The estimated annual retail effect of the proposed surcharge is approximately $1.89 million. EKW at p. 12, EKW Exhibit–14.

Because the costs being requested in this case are incurred in exactly the same manner as the Gavin costs approved by the Commission in the Company's first environmental surcharge case, Case No. 96–489, in making its filing herein, the Company relied upon the following language in the Commission's order in Case No. 96–489:

> The Commission finds that federal preemption mandates our acceptance of the FERC jurisdictional agreements as reasonable. To the extent that environmental costs are part of the total costs Kentucky Power is allocated under the terms of these agreements, the costs must be accepted as reasonable. Contrary to KIUC's position, federal preemption is applicable and controls in this instance, not only for the allowance purchases required under the IAA, but also for the costs Kentucky Power is required to pay under the terms of the Rockport Unit Power Agreement and the Interconnection Agreement. Due to the application of federal preemption, the Commission is required to accept as reasonable the costs incurred under these FERC agreements. Consequently, all of the arguments presented by the AG and KIUC in opposition to the reasonableness of such costs are not appropriate for consideration by this Commission.

Order of May 27, 1997, p. 16, Case No. 96-489 ("1997 Order").

The arguments of the AG and the KIUC referenced by the Commission in its order included the argument that the Gavin scrubber costs the Company was seeking to recover were not reasonable and cost-effective. *Id.* at 15. The Commission disagreed, as it explains in the above quote. The Commission also reviewed numerous court decisions on preemption and declared that "[n]umerous court rulings lead inextricably to the conclusion that actions taken by Kentucky Power pursuant to FERC filed agreements must be presumed to be reasonable by this Commission." *Id.* at 17.

While Kentucky Power believes that this declaration of law in the first surcharge case is controlling and correct, it has, nonetheless, at the request of the Commission Staff, also presented evidence in this proceeding of the steps taken by AEP to ensure that the environmental projects at issue were undertaken in a reasonable and cost-effective manner. Thus, Mr. McManus has again explained the nature of the optimization model used by AEP on an on-going basis to determine that each project is reasonable and cost-effective. Mr. McManus incorporated previous reports and testimony presented in the first two cases that discussed the decision-making process and the alternatives available in detail. *See* KPCo Response to Commission Staff 2nd Data Request, Item 1. The Company also presented all the capital improvement requests (CIs) presented to the AEP management, up to and including the Board of Directors (depending on the amount of the expenditure) for approval of each of the subject projects. These CIs constitute the written evaluation made by the AEPSC in support of each project after it has considered the results of the optimization model runs. The Company has presented these materials in a good faith effort to assure the Commission and its Staff that AEP has undertaken every possible step to ensure the reasonableness and cost-effectiveness of the environmental control projects at issue.

Neither the KIUC nor the AG has challenged the appropriateness or the cost-effectiveness of the individual projects. The Commission Staff, however, has raised questions about the reasons for the SO_3 mitigation projects. Understandably, the Commission Staff had questions concerning statements in the CI for the SO_3 mitigation system indicating that there are no specific regulatory requirements for SO_3 and that the system was being installed in order to address community concerns arising from an SO_3 plume.

At the Hearing, Mr. McManus explained that while there are no regulations directly limiting the SO_3 emission, SO_3 does contribute to conditions that are regulated, (i.e. to formation of a secondary plume) and to operational issues that affect regulatory compliance. At the Hearing, the Staff introduced one page, page 3 of 4 of the Cardinal 1 SO_3 CI. *See* Attachment 2 hereto for the entire CI. Page 4 of 4 explains the operational issues caused by increases in SO_3 emissions associated with the operation of the SCR without mitigation systems. Specifically,

> SO_3, present in the flue gas as H_2SO_4, causes a number of problems. When the flue gas temperature falls below the acid dew point of H_2SO_4, the vapor condenses on the equipment in the flue gas path and causes corrosion. SO_3 in the flue gas that exits the stack forms a secondary plume with a characteristic blue color and elevated visual opacity. While there are currently no regulations specific to SO_3 emission levels, AEP has decided to minimize SO_3 levels and plume visibility where practical.

In a technical paper written by scientists from the U.S. Environmental Protection Agency Office of Research and Development and Riley Power, Inc., the authors discuss approaches to mitigating SO_3 emissions because of these operational problems and potential regulatory concerns. *See* Srivastava, R.K. et al, "Emissions of Sulfur Trioxide from Coal-Fired Power Plants," *Journal of the Air & Waste Management Association*, Volume 54, June 2004, p. 750. They confirm that "[t]here are currently no U.S. regulations that directly limit emissions of SO_3/H_2SO_4 aerosols from utility boilers," but note that other regulatory programs may require SO_3 control. Among the serious operational problems noted by the authors are corrosion, formation of sulfite scale, plugging and fouling of low temperature plant components, and increased loading of particulate control devices. *Id.* at 752. Each of these problems increases the potential for mechanical and other failures that can affect regulatory compliance.

Accordingly, while AEP Management responded promptly to the community concerns regarding the visible changes in the plume after initial operation of the first SCRs, there are other regulatory and operational issues associated with the increase in SO3 concentrations associated with SCR operations that must be addressed. Since the SCR is required to meet CAAA requirements, and increased SO_3 formation is a result of SCR operation that has unacceptable operational and regulatory consequences, SO_3 mitigation costs are directly related to the CAAA requirements and are recoverable under KRS 278.183. Further, as the Cardinal Unit 1 SCR CI demonstrates, AEP considered the available techniques for removing SO_3 and determined the most economical method of achieving the target stack SO_3 concentrations under the circumstances present at the plant. See Attachment 2 hereto at p. 3 of 4.

The testimony of Mr. McManus and Mr. Wagner demonstrates, inter alia,: (1) that the environmental control projects included in the Company's Second Amended Plan are necessary for compliance with the CAAA; (2) that the projects were part of the AEP System plan designed to achieve maximum emission reductions at the least cost; and (3) that the requested environmental costs incurred by Kentucky Power were incurred pursuant to FERC–approved Agreements and, as such, must be presumed reasonable and cost-effective as established in the Commission's Order in Case No. 96–489. Accordingly, the company has met its burden under KRS 278.183.

B. KIUC's witness has provided no valid basis for disallowance of the requested costs.

1. The KIUC is wrong when it argues that federal preemption has no effect in this proceeding.

Although the KIUC has been party to the regulatory and court proceedings involving the preemptive effect of the AEP System agreements that have been approved by FERC, it nonetheless continues to argue that preemption does not apply. In this proceeding, the KIUC

Witness Kollen asserts in his testimony that the Company has proposed "disaggregated rates," and that such rates are not federal rates, and that preemption, therefore, does not apply. Kollen Direct ("LK") at p. 7. In a pretrial motion, the Company asked that Mr. Kollen's testimony be disallowed because it is not factual or legitimate expert testimony but rather is an attempt by a non-legal expert to render an opinion on a question of law. The Commission decided to allow Mr. Kollen's testimony to be submitted, subject to the hearing process. Now, the Company asks this Commission to give Mr. Kollen's testimony on the preemption issue little or no weight because it constitutes a legal opinion about which he is not qualified to testify.

Moreover, the underlying assertions and premises for Mr. Kollen's testimony are false. KPCo is not relying upon the doctrine of Federal preemption to require the Commission to include in the environmental surcharge the whole or any part of the FERC–approved capacity charge. (That effort will come in the Company's next general rate case.) Rather, in this proceeding it is Kentucky statutory law (i.e. KRS 278.183) which requires recovery of environmental compliance costs through a surcharge – not federal preemption. KPCo does rely on Federal preemption to establish that the costs being incurred by KPCo are reasonable for purposes of the environmental surcharge – but this position does not require the "disaggregation" of a preemptive FERC rate; only a reasonable and prudent determination of the environmental costs reflected in the FERC rate – which determination is required by the Kentucky statute. Mr. Kollen's testimony fails to grasp this important distinction.

In Case No. 96-489, this Commission properly recognized the role that federal preemption plays in determining the "reasonableness" of CAAA environmental compliance costs borne by Kentucky Power as a result of the FERC–approved agreements that govern the AEP System. The opinion could not have been more clear on this matter:

> Since Gavin is owned by Ohio Power, a portion of the FERC capacity settlement payment Kentucky Power pays each month includes a portion of the Gavin Scrubber costs.

1997 Order at 13.

> The Commission finds that federal preemption mandates our acceptance of the FERC jurisdictional agreements as reasonable. To the extent that environmental costs are part of the total costs Kentucky Power is allocated under the terms of these agreements, the costs must be accepted as reasonable.

Id. at 16.

Here, Kentucky Power asks this Commission to recognize that it incurs environmental costs through the FERC–approved AEP agreements. KRS 278.183 first requires the Company and the Commission to determine the nature and extent of those costs. Federal preemption then requires this Commission to recognize the identified environmental costs as legitimate and reasonable. Mr. Kollen is simply wrong as a matter of law, when he asserts that the Commission is required to make an independent conclusion about the reasonableness of Federal rates and that preemption cannot, therefore, apply. LK at p. 8. Once identified as environmental costs incurred by KPCo to supply the electricity demands of its customers, the only thing preemption requires is that the Commission find that the costs are reasonable. *See* Order at 16-17, *citing New Orleans Public Service Inc. v. Council of City of New Orleans*, 911 F.2d 993 (5th Cir. 1990).

Moreover, Mr. Kollen is wrong when he asserts that the Commission decision in Case No. 96-489 did not recognize any "disaggregated" portion of the interstate rate as recoverable under the surcharge statute. LK at pp. 8-9. Incredibly, Mr. Kollen states:

> All costs incurred by the Company pursuant to the Interim Allowance Agreement rates were considered to be environmental costs and therefore recoverable through the ECR. In that Order [in Case no. 96-489], there was no disaggregation of the federal rates pursuant to the AEP Interim Allowance Agreement. *Id.* at 9.

Yet, the Order in Case No. 96-489 specifically contradicts this statement when it declares: "Contrary to KIUC's position, federal preemption is applicable and controls in this instance, not only for the allowance purchases required under the IAA, but also for the costs Kentucky Power is required to pay under the terms of the Rockport Unit Power Agreement and the Interconnection Agreement. "1997 Order at 16. The Order further states that the Commission finds "Kentucky Power's portion of the cost for the installation of scrubbers at Gavin" should be included in KPCo's environmental compliance plan and approved recovery of those costs through the environmental surcharge, a retail ratemaking mechanism for purposes of preemption. *Id.* at 19 and 35. For the KIUC and its witness to now maintain that the Commission did not allow a portion of the environmental costs incurred by Kentucky Power pursuant to the Interconnection Agreement is disingenuous at best.

As Mr. Wagner testified at the hearing in this case, the costs the Company now seeks to recover are the same kinds of costs it sought to recover in Case No. 96-489 for the Gavin scrubber. The procedure for determining the proportion of the FERC rate that is attributable to the environmental projects is the same procedure used in Case No. 96-489, and is a straight-forward calculation based on the formulas set out in the Interconnection Agreement. *See* EKW Exhibits.

2. This proceeding is not the appropriate proceeding to consider the treatment of allowances consumed in off-system sales or the treatment of new tax deductions.

The KIUC, through Mr. Kollen, has also attempted both to reopen an issue previously determined and to interject a completely new issue into this proceeding. He argues: (1) that the Company's treatment of SO_2 allowances consumed for off-system sales should be changed so that the expense is no longer reflected in of the System Sales Clause tariff, but instead would be part of the Environmental Surcharge tariff; and (2) that a new provision of the federal tax laws

(IRC § 199) that allows a manufacturing deduction under certain circumstances should be construed as a tax rate reduction for purposes of determining the Company's revenue requirements under the surcharge. The Company filed a pre-hearing motion seeking to have Mr. Kollen's testimony on these issues stricken because they are not before the Commission in this case. By Order dated July 26, 2005, the Commission ruled that these issues are "issues of fact which relate to Kentucky Power's entitlement to surcharge cost recovery under KRS 278.183" and that the Company can present legal arguments in its post-hearing brief on these issues once the evidentiary record is developed. Order of July 26, 2005.

KPCo asks the Commission to reconsider this ruling and to find that these issues are not properly before it in this case. The Kentucky courts have adhered to the fundamental principle of administrative law that an agency is a creature of statute and must strictly conform to the statutory restrictions. See *Department for Natural Resources v. Stearns Coal and Lumber Co.*, Ky., 563 S.W.2d 471, 473 (1978) ("It is fundamental that administrative agencies are creatures of statute and must find within the statute warrant for the exercise of any authority which they claim."); *Flying J Travel Plaza v. Commonwealth, Transportation Cabinet*, Ky., 928 S.W.2d 344, 347 (1996) ("[T]he authority of the agency is limited to a direct implementation of the functions assigned to the agency by the statute."); and *United Sign, Ltd. V. Commonwealth Transportation Cabinet*, Ky. App., 44 S.W.3d 794,798 (2000) ("Any doubts concerning existence or extent of an administrative agency's power should be resolved against the agency.")

The Kentucky Courts have specifically held that the "PSC's powers are statutory" and that "[wh]en a statute prescribes the procedures that an administrative agency must follow, the agency may not add or subtract from those requirements." *Public Service Commission of Kentucky v. Attorney General of the Commonwealth*, Ky. App., 860 S.W. 2d 296 (1993). *See* *also, Union Light, Heat and Power Company v. Public Service Commission*, Ky, 271 S.W.2d 361 (1954). Here the surcharge statute provides for a hearing on the plan submitted by the utility; nothing in the statute provides that an Intervener can inject issues unrelated to the plan presented by the utility.

In attempting to inject arguments unrelated to the petition into this proceeding and further arguing that the costs at issue in the petition are better suited for a general rate case, the KIUC is attempting to treat this cost recovery action as a general rate case in which the PSC should balance the interests of investors and ratepayers. This is precisely the argument that the Kentucky Supreme Court rejected in 1998 when the KIUC argued that the surcharge statute is unconstitutional. *See Kentucky Industrial Utility Customers v. Kentucky Utilities Company*, 983 S.W.2d 493 (1998). The Supreme Court was clear that "the statute provides an alternate procedure to increasing the base rate by allowing utilities to recover the costs of environmental compliance by means of a surcharge rather than by opening a general rate case." *Id.* at 497. Accordingly, this Commission should reject the arguments of the KIUC regarding an alternative treatment for SO_2 allowances and the Section 199 deduction.

3. Even if this proceeding were the appropriate proceeding to consider the allowance issue, the KIUC's position on these matters is incorrect.

a. SO_2 Allowances

In the Company's first environmental surcharge case in 1996, the Company included in its plan a request for a return on SO_2 Emission Allowances purchased by Kentucky Power and that request was granted by the Commission. The Company explained in that proceeding that the AEP System's SO_2 Allowances were governed by a FERC–approved Interim Allowance Agreement ("the IAA"). *See* Response to KIUC 1st Set Data Requests, Item No. 3. Because the System is planned and operated on an integrated and coordinated basis, and because the

Members receive allowances from EPA (as an award or bonus) and through purchase, the IAA was entered into in order to ensure "an equitable methodology of allocation emission allowances and associated costs and benefits between and among the Members." *Id.* at page 6 of 24. The Company presented expert testimony on the manner in which the Company obtained allowances and the requirements of the IAA in the 1996 proceeding.

In its May 27, 1997 Order in Case No. 96-489, the Commission expressly discussed the emission allowances and allowed a return on the Company's allowance inventory. The Commission specifically refers in the Order to the "net gain or net loss resulting from emission allowance **sales**, either from the annual EPA auctions or those amounts allocated to Kentucky Power under the terms of the IAA." 1997 Order at 27 (emphasis added). The Commission ruled that "any EPA auction proceeds and any net gains or net losses allocated to Kentucky Power under the IAA will be included as offsets to the current period revenue requirement in the month received by Kentucky Power." *Id.* at 28. Moreover, the ES Form 3.0 attached to the Order refers to "Net Gains or Net Losses from Emission Allowance **Sales**." *Id.* (Emphasis added).

Kentucky Power believed the Commission's 1997 Order clearly applied to net gains and losses from allowances that were **sold** by AEP to a third party – and did not involve allowances that were **consumed** for off-system sales (as the KIUC is now arguing). Accordingly, KPCo has consistently included in the Environmental Surcharge tariff calculations, only the proceeds from the sales of SO_2 allowances. Moreover, the Company clearly explained to the Commission in responses to data requests in Case No. 96-489 and in the subsequent two-year review case, Case No. 2000-107, that it includes in the environmental surcharge calculations only proceeds from the sale of allowances; and correspondingly the environmental surcharge does not reflect any costs or benefits associated with the consumption of allowances. *See* KPCo Response to Commission Staff 2nd Set, Item No. 1 in Case No. 2000-107 in which the staff asked whether for purposes of the relevant component of ES Form 3.0 Calculation of current Period Revenue Requirements, "are the allowance sales made on a stand--alone basis, or combined with the sales of electricity by Kentucky Power?" The Company responded clearly and simply that allowance sales are made on a stand-alone basis.

Now, in this proceeding, which is not related to the SO_2 allowances, the KIUC has taken another run at the allowance issue, arguing, through its witness, Mr. Kollen, that the Company should treat the consumption of allowances for off-system sales as "sales of allowances" and treat the entire value of the allowance as revenue in the surcharge revenue requirement calculation.

The KIUC approach fails to recognize the critical distinction between the direct sale of allowances and the consumption of allowances for making off-system sales. Currently, and at all times while the environmental surcharge tariff has been in effect, the Company has handled the consumption of allowances under the System Sales Clause Tariff ("SSC Tariff"). The SSC Tariff applies to power sales made to non-affiliated companies and is designed to allow the Company and its ratepayers to share the profits and losses from such sales of power. (This tariff was discussed extensively in prior surcharge proceedings in connection with allocation issues.)

The KIUC now argues that instead of treating consumed SO_2 allowances as an out-of-pocket cost under the SSC Tariff, consumed allowances should be treated as sales of allowances and used in the ES Tariff calculations. As grounds for reversing a ruling that has been in effect for eight years, the KIUC and Mr. Kollen rely upon the provision of the IAA that addresses consumption of allowances for off-system sales. LK at p. 24. This provision calls for redistributions, on an MLR basis, of in-kind or cash reimbursements by customers in such sales or of costs of allowances consumed in such sales. The KIUC now argues that this section of the IAA addresses sales of allowances as that term was used in the Commission's 1997 Order. This argument is just wrong.

Both the Commission in its 1997 Order, and the Company (in its responses to the Commission as well as the AEP System companies in general in the IAA) demonstrate a clear understanding of the difference between a sale of an allowance and consumption of an allowance. As explained above, the Order specifically refers to sales of allowances, not consumption of allowances in sales of power, and the Company clearly advised the Commission more than once that it was using the gains and losses from the sale of allowances on a stand alone basis in its ES Tariff. Moreover, the IAA has two separate provisions relating to sales and consumptions of SO_2 allowances. Section 4.3 of the IAA is entitled "ALLOWANCES **CONSUMED** FOR POWER SALES TO FOREIGN COMPANIES" which has no subsections. Section 4.4, by contrast, is entitled "ALLOWANCE TRANSACTIONS WITH NON-AFFILIATED PARTIES" and has four subsections: subsection 4.41 entitled "**SALE** OF ALLOWANCES"; subsection 4.42 entitled "**PURCHASE** OF ALLOWANCES"; subsection 4.43 entitled "**SALE** OF WITHHELD ALLOWANCES AT EPA AUCTIONS"; and subsection 4.44 entitled "**NET PROCEEDS** AND COSTS FROM PREVIOUS ALLOWANCE TRANSACTIONS." (Emphasis added.) In the introductory paragraph to Section 4.4, it states; "Participation in the allowance market could involve either the **sale or purchase of allowances** to or from non–affiliated parties." Thus the IAA provision that is relevant for purposes of the Commission Order in Case No. 96-489 when the order speaks of "the net gain or loss resulting from emission allowance sales" is Section 4.4—not, as the KIUC argues eight years later, 4.3.

The facts here demonstrate that Kentucky Power has adhered to the Commission's Orders and that the Commission was fully informed when it made its decisions. Now, the KIUC attempts to get another bite at this apple by presenting an incorrect interpretation of previous Commission Orders and interjecting a matter that has long been decided and is not at issue in this case. It should also be noted that the KIUC has attempted to wash NO_x allowances into this spurious allowance argument even though the IAA, which KIUC relies upon for its new-found theory, does not address NO_x allowances at all; and the KIUC has presented incorrect calculations as to the likely effect of this argument on the surcharge. See Wagner Rebuttal Testimony at pp. 7–11. Accordingly, the Commission should disregard the KIUC's argument as to allowances.

b. Tax Issues

The KIUC and Mr. Kollen further argue that the new tax deduction created by the American Jobs Creation Act of 2004 for "domestic manufacturers" (*see* § 199 of the Internal Revenue Code) must be treated by the Commission as a reduction to the federal income tax rate on utility production taxable income. LK at p. 31. Additionally, they argue that § 199 has effectively reduced the Kentucky income tax rate because Kentucky's new tax law incorporates relevant provisions of the federal tax law. *Id.*

Just as the KIUC and Mr. Kollen would have the Commission equate "allowances sold" with "allowances consumed" for purposes of the previous argument, they would have the Commission equate "tax deduction " with "rate reduction" for purposes of their tax argument. There is no basis in law or logic for the Commission to accept this distorted argument.[1]

[1] Certainly, manufacturing members of the KIUC are treating § 199 as a tax deduction – and not as a rate reduction.

As is the pattern of the KIUC, this argument appears to be made because LG&E and KU agreed to treat this deduction as a rate reduction in their recent environmental surcharge cases. *See* June 20, 2005 Orders in Case No. 2004-00421 at p. 22 and Case No. 2004-00426 at p. 28 ("KIUC and LG&E agreed that the gross up factor needed to reflect the impact of the new Internal Revenue Code Section 199 Domestic Manufacturing Deduction and the reduction in the Kentucky corporate income tax rate.") This circumstance should have no bearing on the Commission's decision in this case. What another utility decides to agree to in the give and take of a proceeding can have no precedential effect in this proceeding where Kentucky Power has presented expert testimony as to why the KIUC's arguments are wrong both as a matter of practicality and a matter of law. This is particularly true where Kentucky Power, unlike KU and LG&E, is a member of a much larger group which is treated as a single "expanded affiliated group" ("EAG") for purposes of IRC § 199.

First, and foremost, the characterization of § 199 is clearly found within the terms of the legislation itself. The section declares itself to be a deduction, no mention is made of tax rate:

> (a) Allowance of deduction
>
> There shall be allowed as a deduction ....

The § 199 deduction can be analogized to labor cost and other operating deductions. Indeed, the § 199 deduction is no different than the other tax deductions on the monthly schedules. For example, depreciation is a tax deduction; catalyst amortization expense is a tax deduction; property taxes are income tax deductions; air emission fees are tax deductions; and operation and maintenance expenses are tax deductions. The tax rate is not reduced because of these deductions. There is no basis (and certainly no evidence has been presented) for treating the § 199 deduction any differently than these tax deductions.

Furthermore, contrary to the simplistic explanation of the deduction presented by Mr. Kollen, the IRC § 199 deduction for utilities is not a simple matter that results in a knowable reduction in tax expense. Rather, as the Company's expert witness, Michael Kelley, explained, the deduction for a company depends upon the deduction determined for the EAG based on the EAG's Qualified Production Activity Income ("QPAI"), which is the sum of the positive and negative QPAI of all members of the EAG. Once the EAG's deduction has been determined, the deduction is allocated to members of the EAG that have positive QPAI on a stand–alone basis, and it is not likely that an EAG member's allocated deduction will be equal to its stand-alone deduction. Kelley Rebuttal at p. 4. Moreover, the regulations governing this deduction have not yet been promulgated and the IRS has not made a formal determination as to whether the revenues that are derived from environmental investments will qualify for the deduction. *Id.* at 9 & 10. Thus, the actual effect of § 199 on the bottom line of any utility – especially a utility within the AEP system – cannot be accurately determined. Certainly attempting to implement § 199 as a rate reduction would produce an inaccurate estimate of the tax benefit from the new deduction (especially in view of additional problems caused by new rules affecting net operating losses). As Mr. Kelley explained, it is not correct to treat the IRS § 199 deduction as a tax rate reduction:

> The federal tax rate remains at 35%. And since the amount of the IRC § 199 deduction is determined on an annual basis based upon facts and circumstances not wholly determined at the individual member level within the EAG, the result is a variable income tax expense deduction. There is no basis in the federal tax law to treat this deduction as anything other than a deduction against taxable income; the FERC has defined this item as a deduction; and the accounting authorities have mandated treatment as a deduction. Therefore, the IRC § 199 deduction cannot and should not be treated as an effective tax rate reduction. …
>
> *Id.* at 11 & 12.

The KIUC and Mr. Kollen further note that Kentucky's corporate income tax rate has been reduced to 6%, and he argues that this rate reduction should be captured in the environmental surcharge. However, Mr. Kollen is unduly and unfairly selective in his focus only on the rate component of Kentucky's new corporate income tax law. Indeed, the new law requires the filing of a consolidated return with other members of the AEP System who have some nexus with Kentucky. This, and other changes, might actually result in KPCo's level of tax expense to Kentucky to increase—despite the rate reduction. In the newly created Kentucky consolidated group environment, it just is not as simple as the KIUC would have the Commission believe.

Having said this, KPCo has no objection to having the effects of new changes in federal and state tax laws reflected in the environmental surcharge—the Company just wants those changes to be incorporated at the right time, and in the right way. As noted, KPCo believes that its filing in this case in not the appropriate forum for these issues. But should the Commission disagree, KPCo would propose to amend its ERC Tariff to include a line item for estimated income tax expense—which line item would reflect a negative expense. The Company then would annually reconcile the estimated expense with the actual expense through the ERC surcharge.

IV. <u>CONCLUSION</u>

In this proceeding, Kentucky Power seeks recovery of certain environmental costs required by the CAAAs which it incurs through its membership in the AEP Pool and under the governing FERC-approved Agreements, i.e. the AEP System Interconnection Agreement and the Rockport Unit Power Agreement. Kentucky Power's membership in the AEP Pool ensures that it has sufficient energy reserves to meet its non–coincident peak load even though it does not own enough generating capacity to meet that load. Consequently, Kentucky Power ratepayers benefit substantially from the Company's affiliations with its sister AEP companies. Allowing recovery of the requested costs recognizes the benefits received by Kentucky customers from Kentucky Power's affiliation with the AEP System. Were it not for membership in the AEP System, the Company would have had to incur substantially greater costs to meet its native load, including the full amount of the accompanying environmental compliance costs, than it has under the current arrangement.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Brief of Kentucky Power was served via United States Postal Service, First Class Mail, postage prepaid, upon:

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on this the 19th day of August, 2005.

Judith A. Villines

Judith A. Villines

EXHIBIT JMM-1

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	Continuous Emissions Monitoring System	1995	$635	Title IV Acid Rain Progam
Amos Unit 3	Low NOx Burners	1998	$6,681	Title IV Acid Rain Progam
Amos Unit 3	SCR	2002	$83,916	NOx SIP Call
Cardinal Unit 1	Continuous Emissions Monitoring System	1994	$1,005	Title IV Acid Rain Progam
Cardinal Unit 1	Low NOx Burners	1998	$5,912	Title IV Acid Rain Progam
Cardinal Unit 1	SCR and associated SO3 Mitigation System	2003 (SCR); 2004 (SO3 Mitigation)	$92,978	NOx SIP Call
Gavin Plant Unit 1	Low NOx Burners	1999	$14,431	Title IV Acid Rain Progam
Gavin Plant Unit 1	SCR Catalyst Replacement	2005	$12,962	NOx SIP Call
Gavin Plant Unit 2	Low NOx Burners	1999	$13,472	Title IV Acid Rain Progam
Gavin Plant Common	SCR and associated SO3 Mitigation	2001 (SCR); 2003, 2004 (SO3 Mitigation)	$228,921	NOx SIP Call
Kammer Plant Unit 1	Over Fire Air and Duct Modification	1999 (OFA) 2003 (Duct Mod.)	$1,895	Title IV Acid Rain Program
Kammer Plant Unit 2	Over Fire Air and Duct Modification	1999 (OFA) 2004 (Duct Mod.)	$2,295	Title IV Acid Rain Program
Kammer Plant Unit 3	Over Fire Air and Duct Modification	1999 (OFA) 2003 (Duct Mod.)	$2,293	Title IV Acid Rain Program
Kammer Plant Common	Continuous Emissions Monitoring System	1993	$1,289	Title IV Acid Rain Program
Mitchell Plant Unit 1	Low NOx Burners	1993	$10,413	Title IV Acid Rain Program
Mitchell Plant Unit 1	Water Injection and Low NOx Burner Modifications	2002	$1,597	NOx SIP Call
Mitchell Plant Unit 2	Low NOx Burners	1994	$9,922	Title IV Acid Rain Program
Mitchell Plant Unit 2	Low NOx Burner Modifications	2004	$619	NOx SIP Call
Mitchell Plant Common	Continuous Emissions Monitoring System	1993	$1,419	Title IV Acid Rain Program
Mitchell Plant Common	Replace Burner Barrier Valves	2004	$326	NOx SIP Call
Muskingum River Unit 1	Low NOx Ductwork and Over Fire Air	2000	$1,215	Title IV Acid Rain Program
Muskingum River Unit 1	Over Fire Air Modifications and Water Injection	2003	$1,528	NOx SIP Call

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
Muskingum River Unit 1	Water Injection Modifications	2004	$106	NOx SIP Call
Muskingum River Unit 2	Low NOx Ductwork and Over Fire Air	2000	$1,004	Title IV Acid Rain Program
Muskingum River Unit 2	Over Fire Air Modifications and Water Injection	2004	$1,254	NOx SIP Call
Muskingum River Unit 3	Over Fire Air	2000	$984	Title IV Acid Rain Program
Muskingum River Unit 3	Over Fire Air Modifications	2003	$868	NOx SIP Call
Muskingum River Unit 3	NOx Instrumentation	2004	$276	NOx SIP Call
Muskingum River Unit 4	Over Fire Air	2000	$838	Title IV Acid Rain Program
Muskingum River Unit 4	Over Fire Air Modifications	2004	$819	NOx SIP Call
Muskingum River Unit 5	Low NOx Burners	1994	$5,572	Title IV Acid Rain Program
Muskingum River Unit 5	Low NOx Burner Modifications and Weld Overlays	2004	$2,144	NOx SIP Call
Muskingum River Unit 5	SCR	2005	$98,297	NOx SIP Call
Muskingum River Plant Common	Continuous Emissions Monitoring System	1993	$2,516	Title IV Acid Rain Program
Philip Sporn Unit 2	Low NOx Burners	1997	$2,684	Title IV Acid Rain Program
Philip Sporn Unit 2	Low NOx Burner Modifications	2003	$617	NOx SIP Call
Philip Sporn Unit 4	Low NOx Burners and Modulating Inject. Air	1998	$2,249	Title IV Acid Rain Program
Philip Sporn Unit 4	Low NOx Burner Modifications	2004	$728	NOx SIP Call
Philip Sporn Unit 5	Low NOx Burners and Modulating Inject. Air	1999	$4,597	Title IV Acid Rain Program
Philip Sporn Plant Common	SO_3 Injection System	2003	$3,330	Title I National Ambient Air Quality Standards
Philip Sporn Plant Common	Continuous Emissions Monitoring System	1994	$2,016	Title IV Acid Rain Program

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
Rockport Unit 1	Low NOx Burners	2003	$16,753	NOx SIP Call
Rockport Unit 2	Low NOx Burners	2004	$16,712	NOx SIP Call
Tanners Creek Unit 1	Low NOx Burners	1995	$1,459	Title IV Acid Rain Program
Tanners Creek Unit 1	Low NOx Burner Modifications	2004	$1,300	NOx SIP Call
Tanners Creek Unit 1	Low NOx Burner Leg Replacement	2004	$605	NOx SIP Call
Tanners Creek Unit 2	Low NOx Burners	1998	$2,673	Title IV Acid Rain Program
Tanners Creek Unit 2	Low NOx Burner Modifications	2003	$1,284	NOx SIP Call
Tanners Creek Unit 3	Low NOx Burners	1999	$3,823	Title IV Acid Rain Program
Tanners Creek Unit 3	Low NOx Burner Modifications	2004	$858	NOx SIP Call
Tanners Creek Unit 4	Over Fire Air/Low NOx Burners	2002	$3,419	NOx SIP Call
Tanners Creek Unit 4	ESP Controls Upgrade	2004	$443	Title V Operating Permit Program
Tanners Creek Plant Common	Continuous Emissions Monitoring System	1995 (Unit 4) and 1996 (Units 1-3)	$2,628	Title IV Acid Rain Program

AEP

PROJECT APPROVAL REQUISITION

COPY

Company: Ohio Power **Funding Project Number:** 000007654

Authorization Type: _X_ Capital Improvement
___ Lease Improvement

___ Original Version: ___
_X_ Revision Number: 02

Business Line:	**Generation**
Location:	**Cardinal Unit 1**
Project Title:	**NH_3 Injection System for SO_3 Control (Cardinal Project # 000007653)**
Brief Description:	**The Ammonia (NH_3) Flue Gas Conditioning (FGC) System will be installed to inject NH_3 vapor into the flue gas upstream of the Electrostatic Precipitator (ESP) to reduce the SO_3 emissions at Cardinal Unit 1.**

Project Dates:	**Start:**	**Completion:**	**Authorization for Revision Needed by:**
	01/01/2004	**08/01/2004**	**02/28/2005**

Expenditure to be Authorized [illegible]	Capital	Removal	Total Cost ($)
Previously Approved Amount	967,570	0	967,570
This Submission	64,725	0	64,725
Total ($)	1,032,295	0	1,032,295

Note: Amount to be authorized is the "This Submission" amount

Required Signatures

Authorization Limits	Title	Approver	Signature	Date
amt < $ 10m	Senior VP/or As Delegated	Sigmon, W.	[signature]	3/1/05
$ 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	[signature]	3/2/05

Budget Availability for this Authorization: ___ In Budget ___ Offset

Offset (source & amount): Prior year project. No 2005 funds required.

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		0	1,032,295				1,032,295
Removal		0	0				0
Amount to be Authorized		0	1,032,295				1,032,295
Assoc. O & M			0				0

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

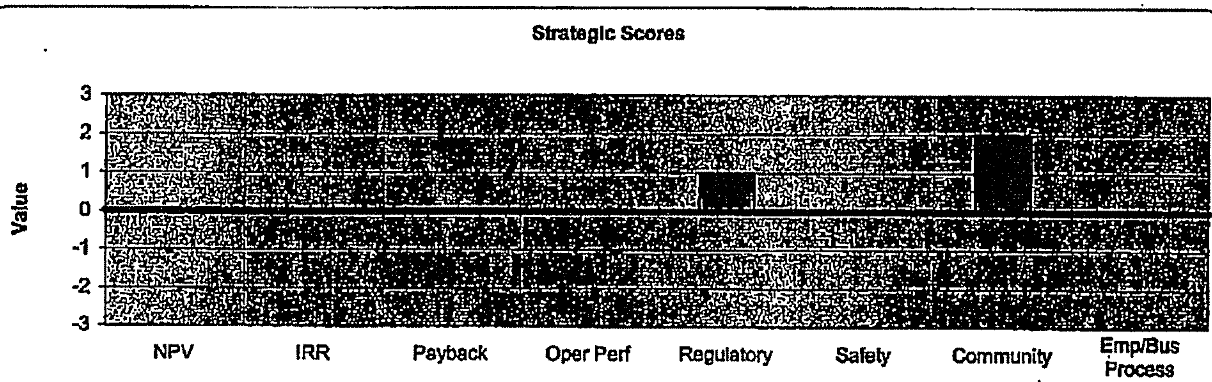
Financial Analysis Summary

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

Note: There are no hard economic benefits to implementing this system. There are potential soft economic benefits related to community relations, but they cannot be quantified.

Scoring Summary

__ Discretionary x Mandated



	NPV	IRR	Payback	Oper Perf	Regulatory	Safety	Community	Emp/Bus Process
Value	0	0	0	0	1	0	2	0

Parameter

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

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

Note: Risk scores assume current fuel scenario based upon low to mid-sulfur fuel usage.
Please see Project Justification and Glossary for explanation of Scores

Project Justification & Explanation of Scores

A typical cost/benefit analysis of this system was not performed because of the lack of economic benefits to installing the system. There are no regulations that limit the SO_3 emissions from Cardinal. However, AEP management has decided to mitigate SO_3 emissions due to community concerns and to avoid adverse publicity similar to that experienced at Gavin. Therefore, the challenge was to determine which method of achieving the target stack SO_3 concentrations was most economical. An ammonia injection system has been selected as the technology of choice due to very low capital and operating costs as compared to other tested SO_3 mitigation methods.

Conclusion

The proposed capital improvement will install an ammonia injection system for year-round SO_3 control on Unit 1. The capital cost for installing the system is estimated at $967,570. The operating cost for maintaining an acceptable stack plume is estimated at $53,000/year. This assumes that a 1.6 lb SO2/MBtu fuel is burned during SCR operation, and 4.5 lb SO2/MBtu during non-SCR operation. The CI cost estimate assumes that contract labor will be used for the installation of the system, due to unavailability of the RSO.

Reason for Revision

The revision is necessary for two reasons. Near the end of the installation phase of the project, the lead engineer was removed by Engineering Services management and assigned to a corporate spend optimization team. A third-party engineer from Shaw Stone & Webster, Inc. was hired to oversee the remainder of the installation and startup. The original engineering estimate in the CI did not include enough funds to cover the cost of the third-party engineer. In addition, the startup of the system lasted longer than expected to address some controls issues and resulted in additional charges that were not accounted for in the CI estimate. There were no changes in the overall scope of the CI, only changes in manpower, and startup delays. As such, the total approved CI amount was exceeded by 7%, and the approved direct amount was exceeded by 10.5%.

Other Alternatives Considered

A number of alternate techniques for removing SO_3 from the flue gas have been tested at Gavin Plant. These include $Mg(OH)_2$ slurry injection in the furnace, $Ca(OH)_2$ injection upstream of the precipitator, sodium sulfite/sodium bisulfite (SBS) injection upstream of the air heater, ammonia injection upstream of the precipitator, and trona injection upstream of the precipitator. The lowest cost means of reducing the stack concentrations of SO_3 is ammonia injection upstream of the precipitator. However, due to concerns about ammonia in the flyash off-gassing and/or raising the ammonia concentration in the flyash pond discharge, this method is only appropriate for units burning low- to mid-sulfur fuels.

Associated / Future Projects

An ammonia injection system has been installed on Cardinal Unit 2, with ammonia supplied by the SCR AOD system. An ammonia injection system had been proposed for Cardinal 1, but was not installed because a low SO_2 to SO_3 conversion catalyst was specified for this SCR. Recent experience has indicated that it would be prudent to incorporate some means of controlling the SO_3 levels even with the installed low conversion catalyst.

Regulatory Issues

Currently, there are no regulatory issues associated with the mitigation of SO_3. However, there is speculation that future PM 2.5 legislation could require the condensable gas portion to be included in particulate matter measurements.

PROJECT APPROVAL REQUISITION

Background Information

Cardinal Unit 1 is permitted to burn fuel with sulfur content up to 7.08 lb SO_2/MBtu. The current fuel strategy calls for burning a low sulfur fuel (nominal sulfur content 1.7 lb SO_2/MBtu) during SCR operation, and a mid-sulfur (nominal 4.5 lb SO_2/MBtu) during non-SCR operation. A portion of the SO_2 generated during coal combustion is further oxidized in the boiler and in the selective catalytic reactor (SCR) used for NOx removal during ozone season. Some SO_3 is removed in the air heater. Without additional control, the stack SO_3 levels are expected to be approximately 16 ppmv when the SCR is not in operation, and 14 - 16 ppmv when the SCR is in operation. Due to variability in conversion rates and other process parameters, stack SO_3 levels could be up to 50% higher than expected.

SO_3, present in the flue gas as H_2SO_4, causes a number of problems. When the flue gas temperature falls below the acid dew point of H_2SO_4, the vapor condenses on the equipment in the flue gas path and causes corrosion. SO_3 in the flue gas that exits the stack forms a secondary plume with a characteristic blue color and elevated visual opacity. While there are currently no regulations specific to SO_3 emission levels, AEP has decided to minimize SO_3 levels and plume visibility where practical.

SO_3 exists as a gas at the economizer/SCR outlet temperature. Once the flue gas cools below 500 F, the SO_3 gas reacts with water vapor in the flue gas to form vapor-phase sulfuric acid (H_2SO_4).

Ammonia reacts with sulfuric acid vapor to form ammonium bisulfate (1) or ammonium sulfate (2), or a mixture of the two products.

$NH_3 (g) + H_2SO_4 (g) \longrightarrow NH_4HSO_4$ (1)

$2NH_3 (g) + H_2SO_4 (g) \longrightarrow (NH_4)_2SO_4$ (2)

The ammonia will be supplied by the existing AOD system.

If the primary reactant is ammonium bisulfate, it is expected that ESP collection efficiency will improve or stay the same with ammonia injection. Any ammonia that is removed in the ESP will be disposed of in the fly ash pond. At this point, some of the ammonia will be destroyed by biological mechanisms in the pond. The ammonia injection rate will be limited by the pond's ability to destroy the ammonia and thereby maintain flyash pond discharge ammonia below the action level.

Project Contacts

Contact	Name	Telephone
Project Manager	Matt Usher	200-3262
Requisition Detail Provider	Matt Usher	200-3262