COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	**)**	**Case No. 2017-00179**

DIRECT TESTIMONY OF

MCMANUS, MILLER, OSBORNE, PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

SECTION III

VOLUME 3 OF 4

June 28, 2017

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

JOHN M. MCMANUS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

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

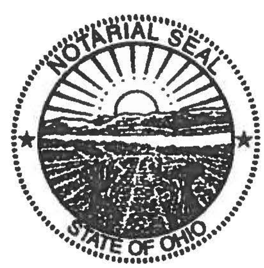
John M McManus

STATE OF OHIO)
) CASE NO. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 21 day of June 2017.

Notary Public

My Commission Expires: 12/31/2019



PATRICK R OTT
Notary Public
In and for the State of Ohio
My Commission Expires
December 31, 2019

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is John M. McManus. I am employed by American Electric Power Service Corporation as Vice President - Environmental Services. American Electric Power Service Corporation ("AEPSC") is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies there from 1976-77. I joined AEPSC's Environmental Engineering Division in September 1977. After holding various positions in the environmental division over the years, I was appointed as Manager, Environmental Services in December 2002 and remained in that position until April 2003. I was appointed to my current position as Vice President - Environmental Services in April 2003. I am also a registered professional engineer in the State of Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT-ENVIRONMENTAL SERVICES?

A. I am responsible for oversight of environmental support for all generation and energy delivery facilities owned by AEP operating companies. Environmental Services provides permitting and compliance support, guidance, procedures, recommendations and training for AEP's operating companies in order to maintain and improve their environmental programs and enhance compliance with environmental laws, regulations, and policies. As part of this effort, Environmental Services is also involved in the development process for environmental regulations and coordinating with operating company staffs to support AEP's corporate strategies and values concerning the environment.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified before the Kentucky Public Service Commission ("Commission") on a number of occasions. In addition, I have testified before the Virginia State Corporation Commission, Indiana Utility Regulatory Commission, Public Service Commission of West Virginia, Public Utilities Commission of Ohio, and I have submitted testimony before the Public Utility Commission of Texas.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe the environmental regulatory requirements that necessitated the Company's updated Environmental

Compliance Plan ("2017 Plan"). The 2017 Plan is described in detail in the testimony of Company Witness Elliott. I will also discuss other applicable and emerging environmental regulations that may drive future updates to the Company's existing Environmental Compliance Plan.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring two exhibits. **EXHIBIT JMM-1** is a copy of the New Source Review ("NSR") Consent Decree (the "Consent Decree") entered into among AEP's eastern utility companies with coal-fired generation including Kentucky Power, the United States Department of Justice ("DOJ"), various states in the northeastern United States, and other involved parties. **EXHIBIT JMM-2** is a copy of the Third Joint Modification to the Consent Decree ("Modified Consent Decree").

IV. CURRENT ENVIRONMENTAL COMPLIANCE

Q. PLEASE DESCRIBE KENTUCKY POWER'S COMPLIANCE WITH APPLICABLE ENVIRONMENTAL REQUIREMENTS.

A. Kentucky Power is in compliance with all current applicable environmental regulations. The environmental controls installed at the Company's Mitchell and Big Sandy Plants, as well as those installed at the Rockport Plant that is the subject of a Unit Power Agreement, ensure the Company complies with applicable environmental regulations. These regulations include the Mercury and Air Toxics Standards Rule ("MATS") and the Cross State Air Pollution Rule ("CSAPR"), as well as the permits issued for the plants under the Clean Air Act and Clean Water Act. The projects required to comply with the Clean Air Act and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal comprise the Company's existing Environmental Compliance Plan.

V. KENTUCKY POWER'S 2017 ENVIRONMENTAL COMPLIANCE PLAN

Q. PLEASE DESCRIBE THE ENVIRONMENTAL COMPLIANCE PROJECTS ADDED BY THE COMPANY IN ITS 2017 PLAN.

A. Kentucky Power proposes to amend its existing Environmental Compliance Plan ("ECP" or "Plan") to add Project 19, the Rockport Unit 1 Selective Catalytic Reduction ("SCR") technology project. The Rockport Unit 1 SCR project will reduce the plant's nitrogen oxide ("NO_X") emissions. While Rockport Unit 1 already employs conventional combustion NO_X controls consisting of low NO_X burners and overfire air, the addition of SCR technology is the most reasonable way to achieve additional significant NO_X emissions reductions from the unit. NO_X is created in the steam generator as a byproduct of the combustion process. The SCR technology injects ammonia as a reagent into the flue gas stream. The ammonia and NO_X are passed through a catalyst where they react on the catalyst surface to form nitrogen gas and water vapor and thereby reduce the NO_X in the flue gas stream. Additional detail about the installation of the Rockport Unit 1 SCR and its cost-effectiveness is included in the testimony of Company Witness Osborne.

Kentucky Power is also proposing to add Project 20 which provides for recovery through the environmental surcharge of costs of consumables, including a return on the inventory of consumables, necessary to operate the projects included in the Company's approved ECP. Additional information about Project 20 is included in the Direct testimony of Company Witness Elliott.

Q. WHAT MANDATES THE SCR RETROFIT AT THE ROCKPORT PLANT?

A. As part of the Clean Air Act and AEP's related Consent Decree, I&M must retrofit Unit 1 of the Rockport Plant with SCR technology by December 31, 2017 to continue operation of this unit. Additionally, in light of the EPA's recent update to CSAPR, discussed further in my testimony, the retrofit of SCR technology on Rockport Unit 1 will aid in ensuring the Plant's compliance with this rulemaking.

Q. PLEASE DESCRIBE THE 2007 NSR CONSENT DECREE.

A. The United States, on behalf of the Federal Environmental Protection Agency ("EPA"), several northeastern states, and fourteen environmental groups filed complaints against several AEP companies including Indiana Michigan Power (counterparty to the Rockport Unit Power Agreement). The complaints sought injunctive relief and civil penalties for alleged violations of the Prevention of Significant Deterioration and Nonattainment New Source Review (NSR) provisions in Part C and D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and federally enforceable state implementation plans developed by Indiana, Ohio, Virginia, and West Virginia. After several years of litigation, the parties negotiated a settlement whose terms are reflected in the Consent Decree. In order to achieve a system-wide settlement and avoid the risk of repetitive litigation, the Consent Decree included all coal-fired units owned or operated by AEP companies in the eastern United States (including certain units like the Rockport units and the Big Sandy units that had not been targeted in the original complaints). The Court entered the Consent Decree as its final order in those cases and continues to administer and enforce the terms of the Consent Decree. A copy of the Consent Decree is included as **EXHIBIT JMM-1**.

Q. HAVE THERE BEEN NEGOTIATED MODIFICATIONS OF THE CONSENT DECREE?

A. Yes. There have been three modifications to the initial Consent Decree, but only the Third Joint Modification is relevant to Kentucky Power. On February 22, 2013, AEP, along with the DOJ, EPA, and other parties, filed the proposed Third Joint Modified Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. The Third Joint Modified Consent Decree provided for the deferral of a high efficiency flue gas desulfurization system ("FGD") until December 31, 2025 on one of the Rockport Units and until December 31, 2028 for the other Rockport Unit. In the interim, the Third Joint Modified Consent Decree required the installation of dry sorbent injection ("DSI") control technology on Rockport Units 1 and 2 by April 16, 2015. A copy of this Third Joint Modified Consent Decree is included as **EXHIBIT JMM-2**.

Q. IS THE INSTALLATION OF SCR TECHNOLOGY AT ROCKPORT UNIT 1 NECESSARY TO COMPLY WITH APPLICABLE ENVIRONMENTAL REQUIREMENTS INCLUDING THE CLEAN AIR ACT?

A. Yes. As the Commission noted in its Order in Case No. 2014-00396, the Consent Decree is an environmental requirement of the Company that specifies the Clean Air Act emission control and monitoring standards, compliance schedules for emissions of SO_2, NO_x and particulate matter, for, among other units, Unit 1 at the Rockport Plant. It also provides stipulated penalties for noncompliance. The Consent Decree mandates that SCR technology be installed at Rockport Unit 1 no later than December 31, 2017. The Company cannot comply with its applicable environmental requirements, including the Clean Air Act as implemented by the Consent Decree as amended, if the SCR technology is not installed.

Q. DO THE PROJECTS LISTED IN KENTUCKY POWER'S 2017 ENVIRONMENTAL COMPLIANCE PLAN MEET THE REQUIREMENTS OF KRS 278.183?

A. Yes. The projects listed in the 2017 Plan are required to comply with the Federal Clean Air Act and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

Q. ARE THERE ANY ADDITIONAL PROJECTS THAT THE COMPANY IS PROPOSING TO INCLUDE IN THE UPDATED 2017 ECP?

A. No. However, on September 7, 2016, the EPA issued a final rule updating the CSAPR to address the 2008 Ozone National Ambient Air Quality Standard ("NAAQS"). This final rule significantly reduced the ozone season NO_x budgets for many of the states covered by the CSAPR. It is effective starting with the 2017 ozone season (May 1, 2017). As a result, the modified NO_x ozone season emission budget for Indiana, in which the Rockport Plant operates, is 50% less than for the previous version of CSAPR. Similarly, the modified NO_x ozone season emission budget for Kentucky (Big Sandy Plant) and West Virginia (Mitchell Plant) are 47% and 29% lower than the previous version of CSAPR, respectively. These changes will impact the use of emission allowances that are included in the Company's ECP.

Q. DO YOU ANTICIPATE THE COMPANY BEING ABLE TO COMPLY WITH THE 2016 UPDATE TO CSAPR?

A. Yes. Under the Company's most recent forecast, and considering the emission reductions of NO_X and SO_2 from the installed SCR and FGD systems, the Company anticipates holding sufficient CSAPR allowances to comply with the 2016 CSAPR update.

VI. <u>ENVIRONMENTAL REQUIREMENTS UNDER EVALUATION</u>

Q. ARE THERE ANY ENVIRONMENTAL REQUIREMENTS THAT THE COMPANY IS CURRENTLY EVALUATING THAT MAY DRIVE FUTURE MODIFICATIONS OF THE COMPANY'S PROPOSED 2017 ENVIRONMENTAL COMPLIANCE PLAN?

A. Yes. There are other current and proposed environmental regulations that may require future investments in environmental controls and corresponding updates to the Company's Environmental Compliance Plan. These environmental regulations include the Coal Combustion Residuals Rule, the Effluent Limitation Guidelines Rule, and the Clean Power Plan.

Q. PLEASE DESCRIBE THESE ENVIRONMENTAL REGULATIONS BEING EVALUATED BY THE COMPANY.

A. Coal Combustion Residuals Rule- EPA issued the final Coal Combustion Residuals ("CCR") Rule on December 19, 2014. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and became effective on October 19, 2015. The CCR Rule is a comprehensive rule applicable to new and existing CCR landfills as well as CCR surface impoundments. It contains requirements, with implementation schedules, for locational restrictions, liner design for new landfills, surface impoundment structural integrity requirements, CCR unit operating criteria, groundwater monitoring and corrective actions, closure and post-closure care, and recordkeeping, notification and internet posting obligations. EPA has not included a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments. Use of existing unlined surface impoundment must cease if groundwater monitoring data indicate there has been a release from the impoundment that exceeds applicable groundwater protection standards.

Currently, the Company is conducting the necessary site-specific analyses to determine whether any modifications or other changes to the Company's existing facilities are required by the CCR Rule. Kentucky Power's Mitchell Plant and I&M's Rockport Plant currently are equipped with dry fly ash handling systems and dry ash landfills to meet current permit requirements. While the evaluations are ongoing, these existing dry fly ash handling and disposal systems may mitigate the impact of the CCR Rule on the plants' future compliance costs.

<u>Effluent Limitations Guidelines (ELG) Rule</u> - On September 30, 2015, EPA finalized a revision to the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating category ("ELG Rule"). The ELG Rule requires compliance with technology-based limits for waste water discharges from power plants. The ELG Rule's main focus is process water and wastewater associated with the handling of coal combustion wastes and by-products from coal-fired generation. Specifically, the ELG Rule will prohibit the discharge of fly ash and bottom ash transport water. It also requires the installation of physical, chemical, and biological treatment for FGD wastewater. The technology-based limits established by the ELG Rule will be incorporated during each plants' next National Pollutant Discharge Elimination System ("NPDES") permit renewal cycle.

The final ELG rule has been appealed and remains in litigation. In March 2017, industry associations filed petitions for reconsideration of the rule with the EPA. In April 2017, EPA announced its intent to grant reconsideration of the rule and issued a stay of the rule's future compliance deadlines, effective upon publication. Additionally, the EPA has been granted a motion seeking a stay of the litigation in the U.S. Court of Appeals for the Fifth Circuit until August 12, 2017. On June 6, 2017, EPA published a notice in the Federal Register seeking public comment on a proposal to revise the compliance schedule for the rule.

The Company's current assessment is that the existing dry fly ash handling system and dry ash landfill, along with the existing wastewater treatment plant for FGD blowdown, may mitigate the impact of the final ELG Rule on

Kentucky Power's Mitchell Plant's compliance costs. Similarly, the Rockport Plant's existing dry fly ash handling system and dry ash landfill may mitigate the impact of the ELG Rule on that plant. Modifications to the bottom ash handling systems at both plants may be needed.

Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan – On August 3, 2015, EPA finalized two rulemakings to regulate CO_2 emissions from fossil fuel-based electric generating units. EPA finalized New Source Performance Standards under Section 111(b) of the Clean Air Act that apply to new fossil units as well as separate standards for modified or reconstructed existing fossil steam units. Separately, EPA finalized a rule referred to as the Clean Power Plan ("CPP"), which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the Clean Air Act. EPA also issued for public comment a proposed Federal Implementation Plan to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance.

On October 23, 2015, a coalition of states filed a lawsuit challenging the CPP and a motion for stay with the D.C. Circuit. On January 21, 2016, the D.C. Circuit denied the coalition's request for stay and agreed to fast-track its consideration of the legal merits of the coalition's CPP challenge. The coalition of states filed a request with the Supreme Court to stay implementation of the CPP on January 26, 2016, and on February 9, 2016, the Supreme Court stayed implementation of the CPP while the rule is under legal review.

In March 2017, EPA filed in the U.S. Court of Appeals for the District of Columbia Circuit notice of 1) an Executive Order from the President of the

United States titled "Promoting Energy Independence and Economic Growth" directing the EPA to review the Clean Power Plan and related rules; 2) the EPA's initiation of a review of the Clean Power Plan and 3) if the EPA determines appropriate, a forthcoming rulemaking related to the Clean Power Plan consistent with the Executive Order. In this same filing, EPA also presented a motion to hold the litigation in abeyance until 30 days after the conclusion of review and any resulting rulemaking. On April 28, 2017, the Court stayed the Clean Power Plan litigation for 60 days and directed parties to the case to file briefs addressing the future of the litigation.

Kentucky Power continues to analyze the available information and engage with the states and other stakeholders in an effort to understand the available program design options and their potential impacts on its operations.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp Civil Action No C2-99-1250 (Consolidated with C2-99-1182)

UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No C2-05-360

OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No. C2-04-1098

CONSENT DECREE

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WHEREAS, the following complaints have been filed against American Electric Power Service Corporation, Indiana Michigan Power Company, Ohio Power Company, Appalachian Power Company, Cardinal Operating Company, and Columbus Southern Power Company in the above-captioned cases, *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-99-1182 and C2-99-1250 ("*AEP I*") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("*AEP II*"):

(a) the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), filed initial complaints on November 3, 1999 and April 8, 2005, and filed amended complaints on March 3, 2000 and September 17, 2004, pursuant to Sections 113(b), 165, and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413, 7475, and 7477;

(b) the States of New York, Connecticut, New Jersey, Vermont, New Hampshire, Maryland, and Rhode Island, and the Commonwealth of Massachusetts, after their motion to intervene was granted, filed initial complaints on December 14, 1999 and November 18, 2004, and filed amended complaints on April 5, 2000, September 24, 2002, and September 17, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604; and

(c) Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Valley Watch, Inc., Ohio Valley Environmental Coalition, West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc. filed an initial complaint on November 19, 1999, and filed amended complaints on January 1, 2000 and September 16, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604;

WHEREAS, the complaints filed against Defendants in *AEP I* and *AEP II* sought injunctive relief and the assessment of civil penalties for alleged violations of, *inter alia*, the:

(a) Prevention of Significant Deterioration and Nonattainment New Source Review provisions in Part C and D of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, 7501-7515; and

(b) federally-enforceable state implementation plans developed by Indiana, Ohio, Virginia, and West Virginia;

WHEREAS, EPA issued notices of violation ("NOVs") to Defendants with respect to such allegations on November 2, 1999, November 22, 1999, and June 18, 2004;

WHEREAS, EPA provided Defendants and the States of Indiana, Ohio, and West Virginia, and the Commonwealth of Virginia, with actual notice pertaining to Defendants' alleged violations, in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, in their complaints, the United States, the States, and Citizen Plaintiffs (collectively, the "Plaintiffs") alleged, *inter alia,* that Defendants made major modifications to major emitting facilities, and failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and further alleged that such emissions damage human health and the environment;

WHEREAS, the Plaintiffs' complaints state claims upon which relief can be granted against Defendants under Sections 113, 165, and 167 of the Act, 42 U.S.C. §§ 7413, 7475, and 7477, and 28 U.S.C. § 1355;

WHEREAS, Defendants have denied and continue to deny the violations alleged in the complaints and NOVs, maintain that they have been and remain in compliance with the Act and are not liable for civil penalties or injunctive relief, and state that they are agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment;

WHEREAS, Defendants have installed and operated SCR technology on several Units in the AEP Eastern System, as those terms are defined herein, during the five (5) month ozone season to achieve emission reductions in compliance with the NO_x SIP Call;

WHEREAS, the Plaintiffs and Defendants anticipate that this Consent Decree, including the installation and operation of pollution control technology and other measures adopted pursuant to this Consent Decree, will achieve significant reductions of emissions from the AEP Eastern System and thereby significantly improve air quality;

WHEREAS, the liability phase of *AEP I* was tried on July 6-7, 2005, and July 11-12, 2005, and no decision has been rendered;

WHEREAS, the Parties have agreed, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

NOW, THEREFORE, without any admission by Defendants, and without adjudication of the violations alleged in the complaints or the NOVs, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113, 167, and 304 of the Act, 42 U.S.C. §§ 7413, 7477, and 7604. Solely for the purposes of this Consent Decree, venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying complaints, and for no other purpose, Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over Defendants, and to venue in this District. Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Solely for the purposes of the complaints filed by the Plaintiffs in this matter and resolved by the Consent Decree, for the purposes of entry and enforcement of this Consent Decree, and for no other purpose, Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in or obligations of any party other than the Plaintiffs and Defendants. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice. To facilitate entry of this Consent Decree, upon the Date of Lodging of this Consent Decree the Parties shall file a Joint Motion to Consolidate *AEP I* and *AEP II* so that *AEP II* is consolidated into *AEP I*.

II. APPLICABILITY

2. Upon entry, the provisions of the Consent Decree shall apply to and be binding upon and inure to the benefit of Plaintiffs and Defendants, and their respective successors and assigns, and upon their officers, employees, and agents, solely in their capacities as such.

3. Defendants shall be responsible for providing a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Defendants shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. For this reason, in any action to enforce this Consent Decree, Defendants shall not assert as a defense the failure of their officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Defendants establish that such failure resulted from a Force Majeure Event, as defined in Paragraph 158 of this Consent Decree.

III. DEFINITIONS

Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

4. A "1-hour Average NO_x Emission Rate" for a re-powered gas-fired, electric generating unit means, and shall be expressed as, the average concentration in parts per million

("ppm") by dry volume, corrected to 15% O_2, as averaged over one (1) hour. In determining the 1-Hour Average NO_x Emission Rate, Defendants shall use CEMS in accordance with applicable reference methods specified in 40 C.F.R. Part 60 to calculate the emissions for each 15-minute interval within each clock hour, except as provided in this Paragraph. Compliance with the 1-Hour Average NO_x Emission Rate shall be shown by averaging all 15-minute CEMS interval readings within a clock hour, except that any 15-minute CEMS interval that contains any part of a startup or shutdown shall not be included in the calculation of that 1-Hour average. A minimum of two 15-minute CEMS interval readings within a clock hour, not including startup or shutdown intervals, is required to determine compliance with the 1-Hour average NO_x Emission Rate. All emissions recorded by CEMS shall be reported in 1-Hour averages.

5. A "30-Day Rolling Average Emission Rate" for a Unit means, and shall be expressed as, a lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to the Unit in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs that occur during a period of Malfunction shall be excluded from the calculation of the 30-Day Rolling Average Emission

Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NO_x and BTU inputs that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a given Unit during any 30-day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NO_x emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the lesser of (i) those NO_x emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NO_x emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time the Unit is synchronized with a utility electric distribution system through the time that the Unit ceases to combust fossil fuel and the fire is out in the boiler.

6. A "30-Day Rolling Average Removal Efficiency" means, for SO_2, at a Unit other than Conesville Unit 5 and Conesville Unit 6, the percent reduction in the mass of SO_2 achieved by a Unit's FGD system over a 30-Operating Day period and shall be calculated as follows: step one, sum the total pounds of SO_2 emitted as measured at the outlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the outlet of the FGD system for that Unit; step two, sum the total pounds of SO_2 delivered to the inlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the inlet to the FGD system for that Unit; step three, subtract the outlet SO_2 emissions calculated in step one from the inlet SO_2 emissions calculated in step two; step four, divide the remainder calculated in step three by the inlet SO_2 emissions calculated in step two; and step five, multiply the quotient calculated in step four by 100 to express as a percentage of removal efficiency. A new 30-day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all emissions that occur during all periods within each Operating Day except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

7. "AEP Eastern System" means, solely for purposes of this Consent Decree, the following coal-fired, electric steam generating Units (with the nominal nameplate net capacity of each Unit):

a. Amos Unit 1 (800 MW), Amos Unit 2 (800 MW), and Amos Unit 3 (1300 MW) located in St. Albans, West Virginia;

b. Big Sandy Unit 1 (260 MW) and Big Sandy Unit 2 (800 MW) located in Louisa, Kentucky;

c. Cardinal Unit 1 (600 MW), Cardinal Unit 2 (600 MW), and Cardinal Unit 3 (630 MW) located in Brilliant, Ohio;

d. Clinch River Unit 1 (235 MW), Clinch River Unit 2 (235 MW), and Clinch River Unit 3 (235 MW) located in Carbo, Virginia;

e. Conesville Unit 1 (125 MW), Conesville Unit 2 (125 MW), Conesville Unit 3 (165 MW), Conesville Unit 4 (780 MW), Conesville Unit 5 (375 MW), and Conesville Unit 6 (375 MW) located in Conesville, Ohio;

f. Gavin Unit 1 (1300 MW) and Gavin Unit 2 (1300 MW) located in Cheshire, Ohio;

g. Glen Lyn Unit 5 (95 MW) and Glen Lyn Unit 6 (240 MW) located in Glen Lyn, Virginia;

h. Kammer Unit 1 (210 MW), Kammer Unit 2 (210 MW), and Kammer Unit 3 (210 MW) located in Moundsville, West Virginia;

i. Kanawha River Unit 1 (200 MW) and Kanawha River Unit 2 (200 MW) located in Glasgow, West Virginia;

j. Mitchell Unit 1 (800 MW) and Mitchell Unit 2 (800 MW) located in Moundsville, West Virginia;

k. Mountaineer Unit 1 (1300 MW) located in New Haven, West Virginia;

l. Muskingum River Unit 1 (205 MW), Muskingum River Unit 2 (205 MW), Muskingum River Unit 3 (215 MW), Muskingum River Unit 4 (215 MW), and Muskingum River Unit 5 (585 MW) located in Beverly, Ohio;

m. Picway Unit 9 (100 MW) located in Lockbourne, Ohio;

n. Rockport Unit 1 (1300 MW) and Rockport Unit 2 (1300 MW) located in Rockport, Indiana;

o. Sporn Unit 1 (150 MW), Sporn Unit 2 (150 MW), Sporn Unit 3 (150 MW), Sporn Unit 4 (150), and Sporn Unit 5 (450 MW) located in New Haven, West Virginia; and

p. Tanners Creek Unit 1 (145 MW), Tanners Creek Unit 2 (145 MW), Tanners Creek Unit 3 (205 MW), and Tanners Creek Unit 4 (500 MW) located in Lawrenceburg, Indiana.

8. "Boiler Island" means: a Unit's (a) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (b) combustion air system; (c) steam generating system (firebox, boiler tubes, and walls); and (d) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic, U.S. EPA (November 25, 1986) and attachments thereto.

9. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

10. "Citizen Plaintiffs" means, collectively, Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Ohio Valley Environmental Coalition,

West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc.

11. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and its implementing regulations.

12. "Clean Air Interstate Rule" or "CAIR" means the regulations promulgated by EPA on May 12, 2005, at 70 Fed. Reg. 25,161, which are entitled, "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to NO_x SIP Call; Final Rule," and any subsequent amendments to that regulation, and any applicable, federally-approved state implementation plan or the federal implementation plan to implement CAIR.

13. "Consent Decree" or "Decree" means this Consent Decree and the appendices attached hereto, which are incorporated into this Consent Decree.

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, ESP, or Other NO_x Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

15. "Date of Entry" means the date this Consent Decree is approved or signed by the United States District Court Judge; provided, however, that if the Parties' Joint Motion to Consolidate, as specified in Paragraph 1, is denied or not decided, then the "Date of Entry"

means the date that the last of the two United States District Court Judges hearing these cases approves or signs this Consent Decree.

16. "Date of Lodging" means the date this Consent Decree is filed for lodging with the Clerk of the Court for the United States District Court for the Southern District of Ohio.

17. "Day" means, unless otherwise specified, calendar day.

18. "Defendants" or "AEP" means American Electric Power Service Corporation, Kentucky Power Company d/b/a American Electric Power, Indiana Michigan Power Company d/b/a American Electric Power, Ohio Power Company d/b/a American Electric Power, Cardinal Operating Company and its owners (Ohio Power and Buckeye Power, Inc.), Appalachian Power Company d/b/a American Electric Power, and Columbus Southern Power Company d/b/a American Electric Power.

19. "Eastern System-Wide Annual Tonnage Limitation" means the limitations, as specified in this Consent Decree, on the number of tons of the air pollutants that may be emitted from the AEP Eastern System during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the air pollutants emitted during all periods of startup, shutdown, and Malfunction, except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

20. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

21. "EPA" means the United States Environmental Protection Agency.

22. "ESP" means electrostatic precipitator, a pollution control device for the reduction of PM.

23. "Environmental Mitigation Project" means a project funded or implemented by Defendants as a remedial measure to mitigate alleged damage to human health or the environment, including National Parks or Wilderness Areas, claimed to have been caused by the alleged violations described in the complaints or to compensate Plaintiffs for costs necessitated as a result of the alleged damages.

24. "Existing Unit" means a Unit that commenced operation prior to the Date of Lodging of this Consent Decree.

25. "Flue Gas Desulfurization System," or "FGD," means a pollution control device with one or more absorber vessels that employs flue gas desulfurization technology for the reduction of SO_2.

26. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

27. An "Improved Unit" for NO_x means an AEP Eastern System Unit equipped with an SCR or scheduled under this Consent Decree to be equipped with an SCR, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for NO_x if it is equipped with an SCR and the requirement to Continuously Operate such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for SO_2 if it is equipped with an FGD and the requirement to Continuously Operate such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

29. "KW" means kilowatt or one thousand watts.

30. "lb/mmBTU" means one pound per million British thermal units.

31. "Malfunction" means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

32. "MW" means a megawatt or one million watts.

33. "NSR Permit" means a preconstruction permit issued by the permitting authority pursuant to Parts C or D of Subchapter I of the Clean Air Act.

34. "National Ambient Air Quality Standards" or "NAAQS" means national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

35. "New and Newly Permitted Unit" means a Unit that commenced operation after the Date of Lodging of this Consent Decree, and that has been issued a final NSR Permit for SO_2 and NO_x that includes applicable Best Available Control Technology ("BACT") and/or Lowest

Achievable Emission Rate ("LAER") limitations, as those terms are respectively defined at 42 U.S.C. §§ 7479(3), 7501(3).

36. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, and its regulations, 40 C.F.R. Part 51.

37. "NO_x" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

38. "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind that has been established under the Clean Air Act or a state implementation plan.

39. "NO_x CAIR Allocations" means the number of NO_x Allowances allocated to the AEP Eastern System Units pursuant to the Clean Air Interstate Rule, excluding any NO_x Allowances awarded by Indiana, Kentucky, Ohio, West Virginia, and Virginia to an AEP Eastern System Unit from the "compliance supplement pool," as that phrase is defined at 40 C.F.R. § 96.143, in a federally-approved state implementation plan, or federal implementation plan to implement CAIR.

40. "Operating Day" means any day on which a Unit fires Fossil Fuel.

41. "Other NO_x Pollution Controls" means the measures identified in the table in Paragraph 69 that will achieve reductions in NO_x emissions at the Units specified therein.

42. "Other SO_2 Measures" means the measures identified in Paragraph 90 that will achieve reductions in SO_2 emissions at the Units specified therein.

43. "Other Unit" means any Unit of the AEP Eastern System that is not an Improved Unit for the pollutant in question.

44. "Operational or Ownership Interest" means part or all of Defendants' legal or equitable operational or ownership interests in any Unit in the AEP Eastern System.

45. "Parties" means the United States, the States, the Citizen Plaintiffs, and Defendants. "Party" means one of the Parties.

46. "Plaintiffs" means the United States, the States, and the Citizen Plaintiffs.

47. "Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River" means the sum of the tons of SO_2 emitted during all periods of operation from the Clinch River plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, in the most recent month and the previous eleven (11) months. A new Annual Rolling Average Tonnage Limitation for years 2010 through 2014, and for 2015 and continuing thereafter, shall be calculated in accordance with Paragraph 88.

48. "Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer" means the sum of the tons of SO_2 emitted during all periods of operation from the Kammer plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (i.e., January 1 through December 31). A new Plant-Wide Annual Tonnage Limitation shall be calculated for each new calendar year.

49. "PM" means particulate matter, as measured in accordance with the provisions of this Consent Decree.

50. "PM CEMS" or "PM Continuous Emission Monitoring System" means the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

51. "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/mmBTU), as measured in annual stack tests in accordance with EPA Method 5, 5B, or 17, 40 C.F.R. Part 60, including Appendix A.

52. "Project Dollars" means Defendants' expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section VIII (Environmental Mitigation Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Environmental Mitigation Projects) and Appendix A of this Consent Decree, and (b) constitute Defendants' direct payments for such projects, or Defendants' external costs for contractors, vendors, and equipment.

53. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, and its regulations, 40 C.F.R. Part 52.

54. "Re-power" means either (1) the replacement of an existing pulverized coal boiler through the construction of a new circulating fluidized bed ("CFB") boiler or other technology of equivalent environmental performance that at a minimum achieves and maintains a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU or a 30-Day Rolling Average Removal Efficiency of at least ninety-five percent (95%) for SO_2 and a 30-Day Rolling Average Emission Rate not greater than 0.070 lb/mmBTU for NO_x; or (2) the modification of

such Unit, or removal and replacement of Unit components, such that the modified or replaced Unit generates electricity through the use of new combined cycle combustion turbine technology fueled by natural gas containing no more than 0.5 grains of sulfur per 100 standard cubic feet of natural gas, and at a minimum, achieves a 1-hour Average NO_x Emission Rate not greater than 2.0 ppm.

55. "Retire" means that Defendants shall: (a) permanently shut down and cease to operate the Unit; and (b) comply with any state and/or federal requirements applicable to that Unit. Defendants shall amend any applicable permits so as to reflect the permanent shutdown status of such Unit.

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NO_x and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO_2, measured in accordance with the requirements of this Consent Decree.

57. "Selective Catalytic Reduction System" or "SCR" means a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions.

58. "Selective Non-Catalytic Reduction" means a pollution control device for the reduction of NO_x emissions that utilizes ammonia or urea injection into the boiler.

59. "SO_2" means sulfur dioxide, as measured in accordance with the provisions of this Consent Decree.

60. "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

61. "SO_2 Allocations" means the number of SO_2 Allowances allocated to the AEP Eastern System Units.

62. "Super-Compliant NO_x Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 80.

63. "Super-Compliant SO_2 Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 98.

64. "States" means the States of Connecticut, Maryland, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, and the Commonwealth of Massachusetts.

65. "Title V Permit" means the permit required for Defendants' major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

66. "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment. An electric steam generating station may comprise one or more Units.

IV. NO_x EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for NO_x.

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP

Eastern System, collectively, shall not emit NO_x in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for NO_x**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016, and each year thereafter	72,000 tons

B. NO_x Emission Limitations and Control Requirements.

68. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	**NO_x Pollution Control**	**Date**
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009

Unit	NO_x Pollution Control	Date
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

69. Other NO_x Pollution Controls. No later than the dates set forth in the table below, Defendants shall Continuously Operate the Other NO_x Pollution Controls on the Units identified therein:

Unit	**Other NO_x Pollution Controls**	**Date**
Big Sandy Unit 1	Low NO_x Burners	Date of Entry
Glen Lyn Units 5 and 6	Low NO_x Burners	Date of Entry
Clinch River Units 1, 2, and 3	Low NO_x Burners, and Selective Non-catalytic Reduction	For Low NO_x Burners, Date of Entry, and, for Selective Non-Catalytic Reduction, December 31, 2009
Conesville Units 5 and 6	Low NO_x Burners	Date of Entry
Kammer Units 1, 2, and 3	Overfire Air	Date of Entry
Kanawha River Units 1 and 2	Low NO_x Burners	Date of Entry
Picway Unit 9	Low NO_x Burners	Date of Entry
Tanners Creek Units 1, 2, and 3	Low NO_x Burners	Date of Entry
Tanners Creek Unit 4	Overfire Air	Date of Entry

C. General Provisions for Use and Surrender of NO_x Allowances.

70. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use NO_x Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation or Eastern System-Wide Annual Tonnage Limitation required by this Decree, by using, tendering,

or otherwise applying NO_x Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

71. As required by this Section IV of this Consent Decree, Defendants shall surrender NO_x Allowances that would otherwise be available for sale, trade, or transfer as a result of actions taken by Defendants to comply with the requirements of this Consent Decree.

72. NO_x Allowances allocated to the AEP Eastern System may be used by Defendants to meet their own federal and/or state Clean Air Act regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 70, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

73. The requirements in this Consent Decree pertaining to Defendants' use and surrender of NO_x Allowances are permanent injunctions not subject to any termination provision of this Consent Decree. These provisions shall survive any termination of this Consent Decree.

D. Use of Excess NO_x Allowances.

74. Calculation of Unrestricted and Restricted NO_x Allowances. On an annual basis, beginning in 2009, Defendants shall calculate the difference between the NO_x CAIR Allocations for the Units in the AEP Eastern System for that year and the annual Eastern System-Wide Tonnage Limitations for NO_x for that calendar year. This difference represents the total Excess NO_x Allowances for that calendar year. For purposes of this Consent Decree, for each year commencing in 2009 and ending in 2015, forty-two percent (42%) of the Excess NO_x Allowances shall be Unrestricted Excess NO_x Allowances and fifty-eight percent (58%) shall be

Restricted Excess NO_x Allowances. Commencing in 2016, and continuing thereafter, all Excess NO_x Allowances shall be Restricted Excess NO_x Allowances.

75. Use and Surrender of Unrestricted Excess NO_x Allowances. For each calendar year commencing in 2009 and ending in 2015, Defendants may use Unrestricted Excess NO_x Allowances in any manner authorized by law. No later than March 1, 2016, Defendants must surrender, or transfer to a non-profit third party selected by Defendants for surrender, all unused Unrestricted Excess NO_x Allowances subject to surrender accumulated during the period from 2009 through 2015.

76. Use and Surrender of Restricted Excess NO_x Allowances. Beginning in calendar year 2009, and for each calendar year thereafter, Defendants shall calculate the difference between the number of any Restricted Excess NO_x Allowances and the number of NO_x Allowances that is equal to the amount of actual NO_x emissions from: (a) any New and Newly Permitted Unit as defined in this Consent Decree, and (b) the following five natural-gas plants but only up to a cumulative total of 1200 tons of NO_x in any single year: Ceredo Generating Station located near Ceredo, West Virginia, with a nominal generating capacity of 505 megawatts; Waterford Energy Center located in southeastern Ohio, with a nominal generating capacity of 821 megawatts; Darby Electric Generating Station located near Columbus, Ohio, with a nominal generating capacity of 480 megawatts; Lawrenceburg Generating Station located in Lawrenceburg, Indiana, with a generating capacity of 1,096 megawatts; and a natural gas-fired power plant under construction near Dresden, Ohio, with a nominal generating capacity of 580 megawatts. This difference shall be the amount of Restricted Excess NO_x Allowances

potentially subject to surrender in 2016. During calendar years 2009 through 2015, Defendants may accumulate Restricted Excess NO_x Allowances potentially subject to surrender in 2016.

77. <u>NO_x Allowances from Renewable Energy.</u> Beginning in calendar year 2009, and for each calendar year thereafter, Defendants may subtract from the number of Restricted Excess NO_x Allowances potentially subject to surrender, a number of allowances calculated in accordance with this Paragraph. To calculate such number, Defendants shall use the following method: multiply 0.0002 by the sum of (a) the actual annual generation in MWH/year generated from solar or wind power projects first owned or operated by Defendants after the Date of Lodging of this Consent Decree, and (b) the actual annual generation in MWH/year purchased by Defendants from solar or wind power projects in any year after the Date of Lodging of this Consent Decree. Such figure so calculated shall be subtracted from the number of Restricted Excess NO_x Allowances potentially subject to surrender each year. The remainder shall be the Restricted Excess NO_x Allowances subject to surrender.

78. Defendants may, solely at their discretion, use Restricted Excess NO_x Allowances at a New and Newly Permitted Unit for which Defendants have received a final NSR Permit from the permitting agency even if the NSR Permit has been appealed but not stayed during the permit appeal process. If Defendants use Restricted Excess NO_x Allowances at such New and Newly Permitted Unit, and the emissions from such New and Newly Permitted Unit are greater than what such Unit is permitted to emit after final adjudication of the appeal process, Defendants shall, within thirty (30) days of such final adjudication, retire an amount of NO_x Allowances equal to the number of tons of NO_x actually emitted that exceeded the finally adjudicated permit limit.

79. No later than March 1, 2016, the total number of Restricted Excess NO_x Allowances subject to surrender accumulated during 2009 through 2015 as calculated in accordance with Paragraphs 74, 76, and 77, shall be surrendered or transferred to a non-profit third party selected by Defendants for surrender, pursuant to Subsection F, below. Beginning in calendar year 2016, and for each calendar year thereafter, the total number of Restricted Excess NO_x Allowances subject to surrender for that year calculated in accordance with Paragraph 74, 76 and 77, shall be surrendered, or transferred to a non-profit third party selected by Defendants for surrender, by March 1 of the following calendar year.

E. Super-Compliant NO_x Allowances.

80. In each calendar year beginning in 2009, and continuing thereafter, Defendants may use in any manner authorized by law any NO_x Allowances made available in that year as a result of maintaining actual NO_x emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for NO_x under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant NO_x Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Method for Surrender of Excess NO_x Allowances.

81. For purposes of this Consent Decree, the "surrender" of Excess Restricted or Unrestricted Excess NO_x Allowances subject to surrender means permanently surrendering to EPA NO_x Allowances from the accounts administered by EPA so that such NO_x Allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

82. For all Restricted or Unrestricted Excess NO_x Allowances subject to surrender required to be surrendered to EPA in Paragraphs 79 and 75, above, Defendants or the third party recipient(s) (as the case may be) shall first submit a NO_x Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NO_x Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NO_x Allowances being surrendered.

83. If any NO_x Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA as required by Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (a) identify the non-profit third party recipient(s) of the NO_x Allowances and list the serial numbers of the transferred NO_x Allowances; and (b) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NO_x Allowances and will not use any of the NO_x Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any NO_x Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the NO_x Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 82 within one (1) year after Defendants transferred the NO_x Allowances to them. Defendants shall not have complied with the NO_x Allowance

surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred NO_x Allowances to EPA.

G. Reporting Requirements for NO_x Allowances.

84. Defendants shall comply with the reporting requirements for NO_x Allowances as described in Section XI (Periodic Reporting) and Appendix B.

H. General NO_x Provisions.

85. To the extent a NO_x Emission Rate is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate.

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for SO_2.

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO_2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons

Calendar Year	Eastern System-Wide Annual Tonnage Limitations for SO_2
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019, and each year thereafter	174,000 tons

B. SO_2 Emission Limitations and Control Requirements.

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	SO_2 Pollution Control	Date
Amos Units 1 and 3	FGD	December 31, 2009
Amos Unit 2	FGD	December 31, 2010
Big Sandy Unit 2	FGD	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009

Unit	SO_2 Pollution Control	Date
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	FGD	December 31, 2015
Rockport Unit 1	FGD	December 31, 2017
Rockport Unit 2	FGD	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

88. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River. Beginning on January 1, 2010, and continuing through December 31, 2014, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 21,700 tons. Beginning on January 1, 2015, and continuing thereafter, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 16,300 tons. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2010, Defendants shall use the period beginning January 1, 2010 through December 31, 2010 to

establish the initial annual period that is subject to the Plant-Wide Annual Rolling Average Tonnage Limitation for 2010 through 2014. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter through December 31, 2014, by averaging the most recent month with the previous eleven (11) months. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2015, Defendants shall use the period beginning January 1, 2015 through December 31, 2015 to establish the initial annual period that is subject to the Plant-Wide Annual Average Rolling Tonnage Limitation for 2015. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter by averaging the most recent month with the previous eleven (11) months.

89. Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer. Beginning on January 1, 2010, and continuing annually thereafter, Defendants shall limit their total annual SO_2 emissions at the Kammer plant to a Plant-Wide Annual Tonnage Limitation of 35,000 tons.

90. Other SO_2 Measures. No later than the dates set forth in the table below, Defendants shall comply with the limit on coal sulfur content for such Units, at all times that the Units are in operation:

Unit	**Other SO_2 Measures**	**Date**
Big Sandy Unit 1	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Glen Lyn Units 5 and 6	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis.	Date of Entry

Unit	Other SO_2 Measures	Date
Kanawha River Units 1 and 2	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Units 1, 2, and 3	Units can only burn coal with a sulfur content no greater than 1.2 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Unit 4	Unit can only burn coal with a sulfur content no greater than 1.2 % on an annual average basis	Date of Entry

C. Use and Surrender of SO_2 Allowances.

91. Defendants may use SO_2 Allowances allocated to the AEP Eastern System by the Administrator of EPA under the Act, or by any state under its state implementation plan, to meet their own federal and/or state regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 92, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitations, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, or Plant-Wide Annual Tonnage Limitation

for SO_2 at Kammer required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

93. On an annual basis beginning in 2010, and continuing thereafter, Defendants shall calculate the number of Excess SO_2 Allowances by subtracting the number of SO_2 Allowances equal to the annual Eastern System-Wide Tonnage Limitations for SO_2 for each calendar year times the applicable allowance surrender ratio from the annual SO_2 Allocations for all Units within the AEP Eastern System for the same calendar year. Defendants shall surrender, or transfer to a non-profit third party selected by Defendants for surrender, all Excess SO_2 Allowances that have been allocated to the AEP Eastern System for the specified calendar year by the Administrator of EPA under the Act or by any state under its state implementation plan. Defendants shall make the surrender of SO_2 Allowances required by this Paragraph to EPA by March 1 of the immediately following calendar year.

D. Method for Surrender of Excess SO_2 Allowances.

94. For purposes of this Subsection, the "surrender" of Excess SO_2 Allowances means permanently surrendering allowances from the accounts administered by EPA so that such allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

95. If any SO_2 Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA pursuant to Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (i) identify the non-profit third party recipient(s) of the SO_2

Allowances and list the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any SO_2 Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 96 within one (1) year after Defendants transferred the SO_2 Allowances to them. Defendants shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred SO_2 Allowances to EPA.

96. For all SO_2 Allowances surrendered to EPA, Defendants or the third party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being surrendered.

97. The requirements in this Consent Decree pertaining to Defendants' surrender of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Consent Decree in whole or in part.

E. Super-Compliant SO_2 Allowances.

98. In each calendar year beginning in 2010, and continuing thereafter, Defendants may use in any manner authorized by law any SO_2 Allowances made available in that year as a result of maintaining actual SO_2 emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for SO_2 under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant SO_2 Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Reporting Requirements for SO_2 Allowances.

99. Defendants shall comply with the reporting requirements for SO_2 Allowances as described in Section XI (Periodic Reporting) and Appendix B.

G. General SO_2 Provisions.

100. To the extent an Emission Rate or 30-Day Rolling Average Removal Efficiency for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate or Removal Efficiency.

101. Notwithstanding Paragraphs 6 and 100, the 30-Day Rolling Average Removal Efficiency for SO_2 at Conesville Unit 5 and Conesville Unit 6 shall be determined in accordance with Appendix C.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of Existing ESPs.

102. Beginning thirty (30) days after the Date of Entry, and continuing thereafter, Defendants shall Continuously Operate each ESP on Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5 to maximize PM emission reductions at all times when the Unit is in

operation, provided that such operation of the ESP is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the ESP. Defendants shall, at a minimum, to the extent reasonably practicable: (a) fully energize each section of the ESP for each unit, and repair any failed ESP section at the next planned Unit outage (or unplanned outage of sufficient length); (b) operate automatic control systems on each ESP to maximize PM collection efficiency; (c) maintain power levels delivered to the ESPs, consistent with manufacturers' specifications, the operational design of the Unit, and good engineering practices; and (d) inspect for and repair during the next planned Unit outage (or unplanned outage of sufficient length) any openings in ESP casings, ductwork, and expansion joints to minimize air leakage.

B. <u>PM Emission Rate and Testing.</u>

103. No later than the dates specified in the table below, Defendants shall Continuously Operate each Unit specified therein to achieve and maintain a PM Emission Rate no greater than 0.030 lb/mmBTU:

Unit	**Date to Achieve and Maintain PM Emission Rate**
Cardinal Unit 1	December 31, 2009
Cardinal Unit 2	December 31, 2009
Muskingum River Unit 5	December 31, 2012

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree.

C. PM Emissions Monitoring.

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits.

106. The reference methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, 5B, or 17, or an alternative method that is promulgated by EPA, requested for use herein by Defendants, and approved for use herein by EPA. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48Da(b) and (e), or any federally-approved method contained in the Ohio State Implementation Plan. Defendants shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA within forty-five (45) days of completion of each test.

D. Installation and Operation of PM CEMS.

107. Defendants shall install, calibrate, operate, and maintain PM CEMS, as specified below. Each PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/mmBTU. Defendants shall maintain, in an electronic database, the hourly average emission values produced by all PM CEMS in lb/mmBTU. Defendants shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

108. No later than December 31, 2011, Defendants shall submit to EPA pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree: (a) a plan for the installation and certification of each PM CEMS, and (b) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Defendants shall use the criteria set forth in 40 C.F.R. Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 3. Following approval by EPA of the protocol, Defendants shall thereafter operate each PM CEMS in accordance with the approved protocol.

109. No later than the dates specified below, Defendants shall install, certify, and operate PM CEMS on the stacks or common stacks for Cardinal Unit 1, Cardinal Unit 2, and a third Unit, as further described in Paragraph 110:

Stack	**Date to Commence Operation of PM CEMS**
Cardinal Unit 1	December 31, 2012
Cardinal Unit 2	December 31, 2012
Unit to be identified pursuant to Paragraph 110	December 31, 2012

110. No later than December 31, 2011, Defendants shall identify, subject to Plaintiffs' approval, the third Unit required by Paragraph 109.

111. No later than ninety (90) days after Defendants begin operation of the PM CEMS, Defendants shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA.

112. <u>Demonstration that PM CEMS are Infeasible.</u> Defendants shall operate the PM CEMS for at least two (2) years on each of the Units specified in Paragraphs 109 and 110. After two (2) years of operation, Defendants may attempt to demonstrate that it is infeasible to continue operating PM CEMS. As part of such demonstration, Defendants shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall explain the basis for stopping operation of the PM CEMS and propose an alternative PM monitoring plan. If the United States disapproves the alternative PM monitoring plan, or if the United States rejects Defendants' claim that it is infeasible to continue operating PM CEMS, such disagreement is subject to Section XV (Dispute Resolution).

113. <u>"Infeasible to Continue Operating PM CEMS" Standard.</u> Operation of a PM CEMS shall be considered no longer feasible if: (a) the PM CEMS cannot be kept in proper

condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol, or (b) Defendants demonstrate that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that Defendants have demonstrated pursuant to this Paragraph that operation is no longer feasible, Defendants shall be entitled to discontinue operation of and remove the PM CEMS.

114. PM CEMS Operations Will Continue During Dispute Resolution or Proposals for Alternative Monitoring. Until EPA approves an alternative monitoring plan, or until the conclusion of any proceeding under Section XV (Dispute Resolution), Defendants shall continue to operate the PM CEMS. If EPA has not issued a decision regarding an alternative monitoring plan within 120 days, Defendants may initiate action under Section XV (Dispute Resolution).

E. PM Reporting.

115. Defendants shall comply with the reporting requirements for PM as described in Section XI (Periodic Reporting) and Appendix B.

F. General PM Provisions.

116. Although stack testing shall be used to determine compliance with the PM Emission Rate established by this Consent Decree, data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions.

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

117. Emission reductions that result from actions required to be taken by Defendants after the Date of Entry of this Consent Decree to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit or offset under the Clean Air Act's Nonattainment NSR and PSD programs.

118. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by a State or EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increment, or air quality related values, including visibility, in a Class I area.

VIII. ENVIRONMENTAL MITIGATION PROJECTS

119. Defendants shall implement the Environmental Mitigation Projects ("Projects") described in Appendix A to this Consent Decree and fund the categories of Projects described in Subsection B, below, in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree. In funding and/or implementing all such Projects in Appendix A and Subsection B, Defendants shall expend moneys and/or implement Projects valued at no less than $36 million for the Projects identified in Appendix A and $24 million for the payments to the States to fund Projects within the categories set forth in Subsection B. Defendants shall fund and/or implement such Projects over a period of no later than five (5) years from the Date of Entry. Defendants may propose establishing one or more qualified settlement funds within the meaning of Treas. Reg. §1.468B-1 in conjunction with one or more

Mitigation Projects. Any such trust would be established pursuant to a trust agreement in a form to be mutually agreed upon by the affected Parties. Nothing in the foregoing is intended by the United States to be a determination or opinion regarding whether such trust would meet the requirements of Treas. Reg. §1.468B-1 or is otherwise appropriate.

A. Requirements for Projects Described in Appendix A ($36 million).

120. Defendants shall maintain, and present to EPA upon request, all documents to substantiate the Project Dollars expended to implement the Projects described in Appendix A, and shall provide these documents to EPA within thirty (30) days of a request for the documents.

121. All plans and reports prepared by Defendants pursuant to the requirements of this Section of the Consent Decree and required to be submitted to EPA shall be publicly available from Defendants without charge.

122. Defendants shall certify, as part of each plan submitted to EPA for any Project, that Defendants are not otherwise required by law to perform the Project described in the plan, that Defendants are unaware of any other person who is required by law to perform the Project, and that Defendants will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards.

123. Defendants shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

124. If Defendants elect (where such an election is allowed) to undertake a Project by contributing funds to another person or entity that will carry out the Project in lieu of Defendants, but not including Defendants' agents or contractors, that person or instrumentality

must, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which Defendants contribute the funds. Regardless of whether Defendants elect (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, Defendants acknowledge that they will receive credit for the expenditure of such funds as Project Dollars only if Defendants demonstrate that the funds have been actually spent by either Defendants or by the person or instrumentality receiving them, and that such expenditures met all requirements of this Consent Decree.

125. Defendants shall comply with the reporting requirements for Appendix A Projects as described in Section XI (Periodic Reporting) and Appendix B.

126. Within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), Defendants shall submit to the United States a report that documents the date that the Project was completed, Defendants' results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

B. Mitigation Projects to be Conducted by the States ($24 million).

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as

designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified in writing by the States. Notwithstanding the $4.8 million and 5-year limitation above, if the total costs of the projects submitted in any one or more years are less than $4.8 million, the difference between that amount and $4.8 million will be available for funding by Defendants of new or previously submitted projects in the following years, except that all amounts not designated by the States within ten (10) years after the Date of Entry of this Consent Decree shall expire.

128. Categories of Projects. The States agree to use money funded by Defendants to implement Projects that pertain to energy efficiency and/or pollution reduction. Such projects may include, but are not limited by, the following:

a. Retrofitting land and marine vehicles (e.g., automobiles, off-road and on-road construction and other vehicles, trains, ferries) and transportation terminals and ports, with pollution control devices, such as particulate matter traps, computer chip reflashing, and battery hybrid technology;

b. Truck-stop and marine port electrification;

c. Purchase and installation of photo-voltaic cells on buildings;

d. Projects to conserve energy use in new and existing buildings, including appliance efficiency improvement projects, weatherization projects, and projects intended to meet EPA's Green Building guidelines (see http://www.epa.gov/greenbuilding/pubs/enviro-issues.htm) and/or the Leadership in Energy and Environmental Design (LEED) Green Building Rating System (see http://www.usgbc.org/DisplayPage.aspx?CategoryID=19), and projects to collect information in rental markets to assist in design of efficiency and conservation programs;

e. Construction associated with the production of energy from wind, solar, and biomass;

f. "Buy back" programs for dirty old motors (e.g., automobile, lawnmowers, landscape equipment);

g. Programs to remove and/or replace oil-fired home heating equipment to allow use of ultra-low sulfur oil, and outdoor wood-fired boilers;

h. Purchase and retirement of SO_2 and NO_x allowances; and

i. Funding program to improve modeling of mobile source sector.

IX. CIVIL PENALTY

129. Within thirty (30) days after the Date of Entry, Defendants shall pay to the United States a civil penalty in the amount of $15,000,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 1999v01542 and DOJ Case Number 90-5-2-1-06893 and the civil action case name and consolidated case numbers of this action. The costs of such EFT shall be Defendants' responsibility. Payment shall be made in accordance with instructions provided to Defendants by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Ohio. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Defendants shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and consolidated case numbers, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

130. Failure to timely pay the civil penalty shall subject Defendants to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Defendants liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

131. Payment made pursuant to this Section is a penalty within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and is not a tax-deductible expenditure for purposes of federal law.

X. RESOLUTION OF CIVIL CLAIMS AGAINST DEFENDANTS

A. Resolution of the United States' Civil Claims.

132. Claims Based on Modifications Occurring Before the Date of Lodging of this Consent Decree. Entry of this Decree shall resolve all civil claims of the United States against Defendants that arose from any modifications commenced at any AEP Eastern System Unit prior to the Date of Lodging of this Consent Decree, including but not limited to, those modifications alleged in the Notices of Violation and complaints filed in *AEP I* and *AEP II*, under any or all of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515; (b) Section 111 of the Clean Air Act, 42 U.S.C. § 7411, and 40 C.F.R. § 60.14; (c) the federally-approved and enforceable Indiana State Implementation Plan, Kentucky State Implementation Plan, Ohio State Implementation Plan, Virginia State Implementation Plan, and West Virginia State Implementation Plan; or (d) Sections 502(a) and 504(a) of Title V of the Clean Air Act, 42 U.S.C §§ 7611(a) and 7611(c), but only to the extent that such claims are based on Defendants' failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111 of the Clean Air Act.

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree also shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or solely for Rockport Unit 2, before December 31, 2019, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

134. Reopener. The resolution of the United States' civil claims against Defendants, as provided by this Subsection A, is subject to the provisions of Subsection B of this Section.

B. Pursuit by the United States of Civil Claims Otherwise Resolved by Subsection A.

135. Bases for Pursuing Resolved Claims for the AEP Eastern System. If Defendants violate: (a) the Eastern System-Wide Annual Tonnage Limitations for NO_x required pursuant to Paragraph 67; (b) the Eastern System-Wide Annual Tonnage Limitations for SO_2 required pursuant to Paragraph 86; or (c) operate a Unit more than ninety (90) days past a date established in this Consent Decree without completing the required installation, upgrade, or commencing Continuous Operation of any emission control device required pursuant to Paragraphs 68, 69, 87, 102, and 103 then the United States may pursue any claim at any AEP Eastern System Unit that is otherwise resolved under Subsection A (Resolution of United States' Civil Claims), subject to (a) and (b) below.

a. For any claims based on modifications undertaken at any Unit in the AEP Eastern System that is not an Improved Unit for the pollutant in question, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five (5) years preceding the violation or failure specified in this Paragraph.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced: (1) after the Date of Lodging of this Consent Decree and (2) within the five (5) years preceding the violation or failure specified in this Paragraph.

136. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to an Improved Unit, the United States may also pursue claims arising

from a modification (or collection of modifications) at an Improved Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims) if the modification (or collection of modifications) at the Improved Unit on which such claim is based (a) was commenced after the Date of Lodging of this Consent Decree and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

137. Any Other Unit can become an Improved Unit for NO_x if (a) it is equipped with an SCR, and (b) the operation of such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit. Any Other Unit can become an Improved Unit for SO_2 if (a) it is equipped with an FGD, and (b) the operation of such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit.

138. Additional Bases for Pursuing Resolved Claims for Modifications at Other Units.

a. Solely with respect to Other Units, i.e., a Unit that is not an Improved Unit under the terms of this Consent Decree, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims), if the modification (or collection of modifications) at the Other Unit on which the claim is based was commenced within the five (5) years preceding any of the following events:

1. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree increases the maximum hourly

emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) (as measured by 40 C.F.R. § 60.14(b) and (h));

2. the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 7) during the period from the Date of Entry of this Consent Decree through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2007 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

3. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase: (i) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603; (ii) causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS; (iii) causes or contributes to violation of a PSD increment; or (iv) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under Subparagraphs (3)(ii) or (3)(iii) of this Paragraph, to pursue any claim for a modification at an Other Unit resolved under Subparagraph A of this Section.

b. Solely with respect to Other Units at the plant listed below, the United States may also pursue claims arising from a modification (or collection of modifications) at such Other Units commenced after the Date of Lodging of this Consent Decree if such modification (or collection of modifications) results in an emissions increase of SO_2 at such Other Unit, and such increase causes the emissions at the plant at issue to exceed the Plant-Wide Annual Rolling

Average Tonnage Limitation for SO_2 at Clinch River listed in the table below for year 2010-2014 and/or 2015 and beyond:

Plant	Year	SO_2 Tons Limit
Clinch River	2010 - 2014	21,700
Clinch River	2015 and each year thereafter	16,300

C. Resolution of Past Claims of the States and Citizen Plaintiffs and Reservation of Rights.

139. The States and Citizen Plaintiffs agree that this Consent Decree resolves all civil claims that have been alleged in their respective complaints or could have been alleged against Defendants prior to the Date of Lodging of this Consent Decree for violations of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and (b) Section 111 of the Act, 42 U.S.C. § 7411, and 40 C.F.R § 60.14, at Units within the AEP Eastern System.

140. The States and Citizen Plaintiffs expressly do not join in giving the Defendants the covenant provided by the United States through Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of this Consent Decree, and reserve their rights, if any, to bring any actions against the Defendants pursuant to 42 U.S.C. § 7604 for any claims arising after the Date of Lodging of this Consent Decree.

141. Notwithstanding Paragraph 140, the States and Citizen Plaintiffs release Defendants from any civil claim that may arise under the Clean Air Act for Defendants' performance of activities that this Consent Decree expressly directs Defendants to undertake,

except to the extent that such activities would cause a significant increase in the emission of a criteria pollutant other than SO_2, NO_x, or PM.

142. Retention of Authority Regarding NAAQS Exceedences. Nothing in this Consent Decree shall be construed to affect the authority of the United States or any state under applicable federal statutes or regulations and applicable state statutes or regulations to impose appropriate requirements or sanctions on any Unit in the AEP Eastern System, including, but not limited to, the Units at the Clinch River plant, if the United States or a state determines that emissions from any Unit in the AEP Eastern System result in violation of, or interfere with the attainment and maintenance of, any ambient air quality standard.

XI. PERIODIC REPORTING

143. Beginning on March 31, 2008, and continuing annually thereafter on March 31 until termination of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Defendants shall submit to the Unites States, the States, and the Citizen Plaintiffs a progress report in compliance with Appendix B of this Consent Decree.

144. In any periodic progress report submitted pursuant to this Section, Defendants may incorporate by reference information previously submitted under their Title V permitting requirements, provided that Defendants attach the Title V permit report, or the relevant portion thereof, and provide a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

145. In addition to the progress reports required pursuant to this Section, Defendants shall provide a written report to the United States, the States, and the Citizen Plaintiffs of any violation of the requirements of this Consent Decree within fifteen (15) days of when Defendants knew or should have known of any such violation. In this report, Defendants shall explain the

cause or causes of the violation and all measures taken or to be taken by Defendants to prevent such violations in the future.

146. Each report shall be signed by Defendants' Vice President of Environmental Services or his or her equivalent or designee of at least the rank of Vice President, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

147. If any SO_2 or NO_x Allowances are surrendered to any third party pursuant to this Consent Decree, the third party's certification pursuant to Paragraphs 83 and 95 shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that, ____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XII. REVIEW AND APPROVAL OF SUBMITTALS

148. Defendants shall submit each plan, report, or other submission required by this Consent Decree to the Plaintiffs specified, whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. The Plaintiff(s) to whom the report is submitted, as required, may approve the submittal or decline to approve it and provide written comments explaining the bases for declining such approval as soon as reasonably practicable. Such Plaintiff(s) will endeavor to coordinate their comments into one document when explaining their bases for declining such approval. Within sixty (60) days of receiving written comments from any of the Plaintiff(s), Defendants shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to the Plaintiff(s); or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

149. Upon receipt of Plaintiffs' or Plaintiff's (as the case may be) final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, Defendants shall implement the approved submittal in accordance with the schedule specified therein.

XIII. STIPULATED PENALTIES

150. For any failure by Defendants to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution), Defendants shall pay, within thirty (30) days after receipt of written demand to Defendants by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per day per violation
d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per day per violation

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
e. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for SO_2	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
f. Failure to comply with the Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River	\$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
g. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for NO_x	\$5,000 per ton for the first 1000 tons, and \$10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 82 and 83, of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
h. Failure to install, commence operation, or Continuously Operate a pollution control device required under this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter
i. Failure to Retire, Retrofit, or Re-power a Unit by the date specified in this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
j. Failure to install or operate CEMS as required in this Consent Decree	$1,000 per day per violation
k. Failure to conduct performance tests of PM emissions, as required in this Consent Decree	$1,000 per day per violation
l. Failure to apply for any permit required by Section XVI (Permits)	$1,000 per day per violation
m. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required in this Consent Decree	$750 per day per violation during the first ten days, $1,000 per day per violation thereafter
n. Using NO_x Allowances except as permitted by Paragraphs 75, 76, and 78	The surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used in violation of this Consent Decree
o. Failure to surrender NO_x Allowances as required by Paragraphs 75 and 79	(a) $32,500 per day plus (b) $7,500 per NO_x Allowance not surrendered
p. Failure to surrender SO_2 Allowances as required by Paragraph 93	(a) $32,500 per day plus (b) $1,000 per SO_2 Allowance not surrendered
q. Failure to demonstrate the third party surrender of an SO_2 Allowance or NO_x Allowance in accordance with Paragraphs 95-96 and 82-83.	$2,500 per day per violation
r. Failure to implement any of the Environmental Mitigation Projects described in Appendix A in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	The difference between the cost of the Project, as identified in Appendix A, and the dollars Defendants spent to implement the Project

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
s. Failure to fund an Environmental Mitigation Project, as submitted by the States, in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
t. Failure to Continuously Operate required Other NO_x Pollution Controls required in Paragraph 69	$10,000 per day during the first 30 days, and $32,500 each day thereafter
u. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96 of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
v. Any other violation of this Consent Decree	$1,000 per day per violation

151. Violation of an Emission Rate or 30-Day Rolling Average Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Where a violation of a 30-Day Rolling Average Emission Rate or 30-Day Rolling Average Removal Efficiency (for the same pollutant and from the same source) recurs within periods of less than thirty (30) days, Defendants shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

152. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

153. Defendants shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to Defendants from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless Defendants elect within twenty (20) days of receipt of written demand to Defendants from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

154. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 152 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, Defendants shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in Subparagraph c, below;

c. If the Court's decision is appealed by any Party, Defendants shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with interest accrued on such stipulated penalties determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the accrued stipulated penalties agreed by the Plaintiffs and Defendants, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 150.

155. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

156. Should Defendants fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

157. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to Plaintiffs by reason of Defendants' failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, Defendants shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XIV. FORCE MAJEURE

158. For purposes of this Consent Decree, including, but not limited to, Paragraphs 67 and 86, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Defendants or any entity controlled by Defendants that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

159. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Defendants intend to assert a claim of Force Majeure, Defendants shall notify the Plaintiffs in writing as soon as practicable, but in no event later than twenty-one (21) business days following the date Defendants first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, Defendants shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Defendants to prevent or minimize the delay or violation, the schedule by which Defendants propose to implement those measures, and Defendants' rationale for attributing a delay or violation to a Force Majeure Event. Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. Defendants shall be deemed to know of any circumstance which Defendants or any entity controlled by Defendants knew or should have known.

160. Failure to Give Notice. If Defendants materially fail to comply with the notice requirements of this Section, the Plaintiffs may void Defendants' claim for Force Majeure as to the specific event for which Defendants have failed to comply with such notice requirement.

161. Plaintiffs' Response. The Plaintiffs shall notify Defendants in writing regarding Defendants' claim of Force Majeure as soon as reasonably practicable. If the Plaintiffs agree that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event, or the extent to which Defendants may be relieved of stipulated penalties or other remedies provided under the terms of this Consent Decree. Such agreement shall be reduced to writing, and signed by all Parties. If the agreement results in a material change to the terms of this Consent Decree, an appropriate modification shall be made pursuant to Section XXII (Modification). If such change is not material, no modification of this Consent Decree shall be required.

162. Disagreement. If Plaintiffs do not accept Defendants' claim of Force Majeure, or if the Plaintiffs and Defendants cannot agree on the length of the delay actually caused by the Force Majeure Event, or the extent of relief required to address the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XV (Dispute Resolution) of this Consent Decree.

163. Burden of Proof. In any dispute regarding Force Majeure, Defendants shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Defendants shall also bear the burden of proving that Defendants gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a

Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

164. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Defendants' obligations under this Consent Decree shall not constitute a Force Majeure Event.

165. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Defendants' response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; unanticipated coal supply or pollution control reagent delivery interruptions; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs Defendants to operate an AEP Eastern System Unit in response to a local or system-wide (state-wide or regional) emergency (which could include unanticipated required operation to avoid loss of load or unserved load). Depending upon the circumstances and Defendants' response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Defendants and Defendants have taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

166. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Plaintiffs and Defendants by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the Plaintiffs or approved by the Court. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule (provided that Defendants shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

XV. DISPUTE RESOLUTION

167. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Parties.

168. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Parties advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

169. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend

this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually agreed upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

170. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide Defendants with a written summary of their position regarding the dispute. The written position provided by Plaintiffs shall be considered binding unless, within forty-five (45) days thereafter, Defendants seek judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) days of filing. In their initial filings with the Court under this Paragraph, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

171. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party's basis for seeking such a scheduling modification.

172. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

173. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance

with the extended or modified schedule, provided that Defendants shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

174. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 170, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVI. PERMITS

175. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Defendants to secure a permit to authorize construction or operation of any device contemplated herein, including all preconstruction, construction, and operating permits required under state law, Defendants shall make such application in a timely manner. Defendants shall provide Notice to Plaintiffs under Section XVIII (Notices), for each Unit that Defendants submit an application for any permit described in this Paragraph 175.

176. Notwithstanding the previous Paragraph, nothing in this Consent Decree shall be construed to require Defendants to apply for or obtain a PSD or Nonattainment NSR permit for physical changes in, or changes in the method of operation of, any AEP Eastern System Unit that would give rise to claims resolved by Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141 of this Consent Decree.

177. When permits are required as described in Paragraph 175, Defendants shall complete and submit applications for such permits to the appropriate authorities to allow time for all legally required processing and review of the permit request, including requests for additional

information by the permitting authorities. Any failure by Defendants to submit a timely permit application for any Unit in the AEP Eastern System shall bar any use by Defendants of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

178. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term or limit has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

179. Within three (3) years from the Date of Entry of this Consent Decree, and in accordance with federal and/or state requirements for modifying or renewing a Title V permit, Defendants shall amend any applicable Title V permit application, or apply for amendments to their Title V permits, to include a schedule for any Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations. For Units subject to a requirement to Retire, Retrofit, or Re-power, Defendants shall apply to modify, renew, or obtain any applicable Title V permit to include a schedule for any Unit-specific performance, operation, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations, within (12) twelve months of making such election to Retire, Retrofit, or Re-power.

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer.

181. Defendants shall provide the United States with a copy of each application for a federally-enforceable non-Title V permit or amendment to a state implementation plan, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment period.

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

183. If Defendants sell or transfer to an entity unrelated to Defendants ("Third-Party Purchaser") part or all of Defendants' Ownership Interest in a Unit in the AEP Eastern System,

Defendants shall comply with the requirements of Section XIX (Sales or Transfers of Operational or Ownership Interests) with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, Defendants remain the holder of the Title V permit for such facility.

XVII. INFORMATION COLLECTION AND RETENTION

184. Any authorized representative of the United States, including attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the AEP Eastern System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Defendants or their representatives, contractors, or consultants; and

d. assessing Defendants' compliance with this Consent Decree.

185. Defendants shall retain, and instruct their contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in their or their contractors' or agents' possession or control (with the exception of their contractors' copies of field drawings and specifications), and that directly relate to Defendants' performance of their obligations under this Consent Decree until six (6) years following completion of performance of such obligations. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

186. All information and documents submitted by Defendants pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of

documents unless (a) the information and documents are subject to legal privileges or protection or (b) Defendants claim and substantiate in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

187. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Defendants' facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations, or permits.

XVIII. NOTICES

188. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Air Enforcement & Compliance Assurance Branch
U.S. EPA Region V
77 W. Jackson St.
Mail Code AE17J
Chicago, IL 60604

and

Air Protection Division Director
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103

As to the State of Connecticut:

Office of the Attorney General
Environmental Department
P.O. Box 120
Hartford, Connecticut
06141-0120

As to the State of Maryland:

Frank Courtright
Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, Maryland 21230
fcourtright@mde.state.md.us

As to the Commonwealth of Massachusetts:

Frederick D. Augenstern, Assistant Attorney General
Office of the Attorney General
1 Ashburton Place, 18th floor
Boston, Massachusetts 02108
fred.augenstern@state.ma.us

and

Douglas Shallcross, Esquire
Department of Environmental Protection
Office of General Counsel
1 Winter Street
Boston, Massachusetts 02108
Douglas.Shallcross@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
Concord, New Hampshire 03302-0095

As to the State of New Jersey:

Kevin P. Auerbacher
Section Chief
Environmental Enforcement Section
R.J. Hughes Justice Complex
25 Market Street
P.O. Box 093
Trenton, New Jersey 08625-0093

As to the State of New York:

Robert Rosenthal
Assistant Attorney General
New York State Attorney General's Office
The Capitol
Albany, New York 12224

As to the State of Rhode Island:

Tricia K. Jedele
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903
(401) 274-4400, Ext. 2400
tjedele@riag.ri.gov

As to the State of Vermont:

Environmental Division
Office of the Attorney General
109 State Street
Montpelier, Vermont 05609-1001

and

Director
Air Pollution Control Division
Department of Environmental Conservation
Agency of Natural Resources
Building 3 South
103 South Main Street
Waterbury, Vermont 05671-0402

As to the Citizen Plaintiffs:

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, New York 10011
(212) 727-4414
nmarks@nrdc.org

and

Albert F. Ettinger
Environmental Law and Policy Center
35 East Wacker Dr. Suite 1300
Chicago, Illinois 60601-2110
(312) 673-6500
aettinger@elpc.org

As to Defendants:

Vice President, Environmental Services
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
jmmcmanus@aep.com

and

General Counsel
American Electric Power
1 Riverside Plaza
Columbus, OH 43215
jbkeane@aep.com

189. All notifications, communications, or submissions made pursuant to this Section shall be sent as follows: (a) by overnight mail or overnight delivery service to the United States;

and (b) by electronic mail to all Plaintiffs, if practicable, but if not practicable, then by overnight mail or overnight delivery service to the States and Citizen Plaintiffs. All notifications, communications, and transmissions sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

190. Any Party may change either the notice recipient or the address for providing notices to it by serving all other Parties with a notice setting forth such new notice recipient or address.

XIX. SALES OR TRANSFERS OF OPERATIONAL OR OWNERSHIP INTERESTS

191. If Defendants propose to sell or transfer an Operational or Ownership Interest to an entity unrelated to Defendants ("Third Party"), they shall advise the Third Party in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

192. No sale or transfer of an Operational or Ownership Interest shall take place before the Third Party and Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party a party to this Consent Decree and jointly and severally liable with Defendants for all the requirements of this Decree that may be applicable to the transferred or purchased Interests.

193. This Consent Decree shall not be construed to impede the transfer of any Interests between Defendants and any Third Party so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Defendants and any Third Party – of the burdens of compliance with this Decree,

provided that both Defendants and such Third Party shall remain jointly and severally liable for the obligations of the Consent Decree applicable to the transferred or purchased Interests.

194. If the Plaintiffs agree, the Plaintiffs, Defendants, and the Third Party that has become a party to this Consent Decree pursuant to Paragraph 192, may execute a modification that relieves Defendants of liability under this Consent Decree for, and makes the Third Party liable for, all obligations and liabilities applicable to the purchased or transferred Interests. Notwithstanding the foregoing, however, Defendants may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Interests, including the obligations set forth in Section VIII (Environmental Mitigation Projects), Paragraphs 86 and 67, and Section IX (Civil Penalty).

195. Defendants may propose and Plaintiffs may agree to restrict the scope of joint and several liability of any purchaser or transferee for any AEP Eastern System obligations to the extent such obligations may be adequately separated in an enforceable manner using the methods provided by or approved under Section XVI (Permits).

196. Paragraphs 191-195 of this Consent Decree do not apply if an Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as Defendants: (a) remain the operator (as that term is used and interpreted under the Clean Air Act) of the subject AEP Eastern System Unit(s); (b) remain

subject to and liable for all obligations and liabilities of this Consent Decree; and (c) supply Plaintiffs with the following certification within thirty (30) days of the sale or transfer:

> "Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. We, the Chief Executive Officer and General Counsel of American Electric Power ("AEP"), hereby jointly certify under Title 18 U.S.C. Section 1001, on our own behalf and on behalf of AEP, that any change in AEP's Ownership Interest in any AEP Eastern System Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date] between AEP and [insert applicable entity]: a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; b) does not impair AEP's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action No. C2-99-1250 ("AEP I") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("AEP II"); c) does not affect AEP's operational control of any Unit covered by that Consent Decree in a manner that is inconsistent with AEP's performance of its obligations under the Consent Decree; and d) in no way affects the status of AEP's obligations or liabilities under that Consent Decree."

XX. EFFECTIVE DATE

197. The effective date of this Consent Decree shall be the Date of Entry.

XXI. RETENTION OF JURISDICTION

198. The Court shall retain jurisdiction of this case after the Date of Entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXII. MODIFICATION

199. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXIII. GENERAL PROVISIONS

200. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The limitations and requirements set forth herein do not relieve Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act at any Units covered by this Consent Decree, including the Defendants' obligation to satisfy any state modeling requirements set forth in a state implementation plan.

201. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

202. In any subsequent administrative or judicial action initiated by any of the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by any of the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph affects the validity of Paragraphs Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141.

203. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Defendants of their obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section X (Resolution of Civil

Claims Against Defendants), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

204. At any time prior to termination of this Consent Decree, Defendants may request approval from Plaintiffs to implement other control technology for SO_2 or NO_x than what is required by this Consent Decree. In seeking such approval, Defendants must demonstrate that such alternative control technology is capable of achieving pollution reductions equivalent to an FGD (for SO_2) or SCR (for NO_x) at the Units in the AEP Eastern System at which Defendants seek approval to implement such other control technology for SO_2 or NO_x. Approval of such a request is solely at the discretion of the Plaintiffs.

205. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8314 (Feb. 24, 1997)) concerning the use of data for any purpose under the Act generated either by the reference methods specified herein or otherwise.

206. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

207. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. Defendants shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual

Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Defendants shall report data to the number of significant digits in which the standard or limit is expressed.

208. This Consent Decree does not limit, enlarge, or affect the rights of any Party to this Consent Decree as against any third parties.

209. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

210. Except for Citizen Plaintiffs, each Party to this action shall bear its own costs and attorneys' fees. Defendants shall reimburse the Citizen Plaintiffs' attorneys' fees and costs, pursuant to 42 U.S.C. § 7604(d), and the agreement between counsel for Defendants and Citizen Plaintiffs within thirty (30) days of the Date of Entry of this Consent Decree.

XXIV. SIGNATORIES AND SERVICE

211. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

212. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

213. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXV. PUBLIC COMMENT

214. The Parties agree and acknowledge that final approval by the United States and the entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate. The Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

215. Termination as to Completed Tasks. As soon as Defendants complete a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, Defendants may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

216. Conditional Termination of Enforcement Through the Consent Decree. After Defendants:

a. have successfully completed construction, and have maintained Continuous Operation, of all pollution controls as required by this Consent Decree;

b. have obtained final Title V permits (i) as required by the terms of this Consent Decree; (ii) that cover all Units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in this Consent Decree; and

c. certify that the date is later than December 31, 2022;

then Defendants may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of Defendants' certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

217. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 216, if enforcement of a provision in this Consent Decree cannot be pursued by a Party under the applicable Title V permit, or if a Consent Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Consent Decree at any time.

XXVII. FINAL JUDGMENT

218. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment among the Parties.

IT IS SO ORDERED, this _10th_ day of December, 2007.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

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Signature Page for Consent Decree in:

United States of America
v.
American Electric Power Service Corp , et al.

FOR THE UNITED STATES OF AMERICA:

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MARK D'ALESSANDRO
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v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

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GRANTA Y. NAKAYAMA
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Walker B. Smith

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FOR THE STATE OF NEW JERSEY:

Very Truly Yours,

ANNE MILGRAM
ATTORNEY GENERAL OF NEW JERSEY

By: ______________________
Jon C. Martin
Deputy Attorney General

Signature Page for Consent Decree in:

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FOR THE STATE OF NEW YORK:

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Signature Page for Consent Decree in:

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FOR CITIZEN PLAINTIFFS:

Nancy S Marks

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(212) 727-4414

For Citizen Plaintiffs Sierra Club and
Natural Resources Defense Council, Inc.

Signature Page for Consent Decree in:

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FOR CITIZEN PLAINTIFFS:

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For Citizen Plaintiffs Ohio Citizen Action,
CitizensAction Coalition of Indiana,
Hoosier Environmental Council,
Ohio Valley Environmental Coalition,
West Virginia Environmental Council,
Clean Air Council,
Izaak Walton League of America,
United States Public Interest Research Group,
National Wildlife Federation,
Indiana Wildlife Federation
and League of Ohio Sportsmen

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FOR CITIZEN PLAINTIFFS:

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Local Counsel for Sierra Club and
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FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:

NICHOLAS K. AKINS
Executive Vice President – Generation

APPENDIX A
ENVIRONMENTAL MITIGATION PROJECTS

In compliance with and in addition to the requirements in Section VIII of this Consent Decree (Environmental Mitigation Projects), Defendants shall comply with the requirements of this Appendix to ensure that the benefits of the $36 million in federally directed Environmental Mitigation Projects are achieved.

I. National Parks Mitigation

A. Within 45 days from the Date of Entry, Defendants shall pay to the National Park Service the sum of $2 million to be used in accordance with the Park System Resource Protection Act, 16 U.S.C. § 19jj, for the restoration of land, watersheds, vegetation, and forests using adaptive management techniques designed to improve ecosystem health and mitigate harmful effects from air pollution. This may include reforestation or restoration of native species and acquisition of equivalent resources and support for collaborative initiatives with state and local agencies and other stakeholders to develop plans to assure resource protection over the long-term. Projects will focus on one or more of the following Class I areas alleged in the underlying action to have been injured by emissions from Defendants facilities: Shenandoah National Park, Mammoth Cave National Park, and Great Smoky Mountains National Park.

B. Payment of the amount specified in the preceding paragraph shall be made to the Natural Resource Damage and Assessment Fund managed by the United States Department of the Interior. Instructions for transferring funds will be provided to the Defendants by the National Park Service. Notwithstanding Section I.A of this Appendix, payment of funds by Defendants is not due until ten (10) days after receipt of payment instructions.

C. Upon payment of the required funds into the Natural Resource Damage and Assessment Fund, Defendants shall have no further responsibilities regarding the implementation of any project selected by the National Park Service in connection with this provision of the Consent Decree.

II. Overall Environmental Mitigation Project Schedule and Budget

A. Within 120 days of the Date of Entry, as further described below, Defendants shall submit plans to EPA for review and approval for completing the remaining $34 million in federally directed Environmental Mitigation Projects specified in this Appendix over a period of not more than five (5) years from the Date of Entry. EPA will consult with the Citizen Plaintiffs, through their counsel, prior to approving or commenting on any proposed plan. The Parties agree that Defendants are entitled to spread their payments for Environmental Mitigation Projects evenly over the five-year period commencing upon the Date of Entry. Defendants are not, however, precluded from accelerating payments to better effectuate a proposed mitigation plan, provided however, Defendants shall not be entitled to any reduction in the nominal amount of the required payments by virtue of the early expenditures. EPA may, but is not required to, approve a proposed Project budget that results in a back-loading of some expenditures. EPA shall determine prior to approval that all Projects are consistent with federal law.

B. Defendants may, at their election, consolidate the plans required by this Appendix into a single plan.

C. In addition to the requirements set forth below, Defendants shall submit within 120 days of the Date of Entry, a summary-level budget and Project time-line that covers all of the Projects proposed.

D. Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

E. Within 60 days following the completion of each Project required under Appendix A, Defendants shall submit to the United States and Citizen Plaintiffs a report that documents the date that the Project was completed, the results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

F. Upon approval of the plans required by this Appendix by EPA, Defendants shall complete the Environmental Mitigation Projects according to the approved plans. Nothing in this Consent Decree shall be interpreted to prohibit Defendants from completing Environmental Mitigation Projects before the deadlines specified in the schedule of an approved plan.

III. Acquisition and Restoration of Ecologically Significant Areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia

A. Within 120 days of the Date of Entry, and on each anniversary of the initial submission for the following four (4) years, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for acquisition and/or restoration of ecologically significant areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia ("Land Acquisition and Restoration"). Defendants shall spend no less than a total of $10 million in Project Dollars on Land Acquisition and Restoration over the five year period provided under this Appendix for completion of federally directed Environmental Mitigation Projects.

B. Defendants' proposed plan shall:

1. Describe the proposed Land Acquisition and Restoration projects in sufficient detail to allow the reader to ascertain how each proposed action meets the requirements set out below. For purposes of this Appendix and Section VIII (Environmental Mitigation Projects) of this Consent Decree, land acquisition means purchase of interests in land, including fee ownership, easements, or other restrictions that run with the land that provide for perpetual protection of the acquired land. Restoration may include, by way of illustration, direct reforestation (particularly of tree species that may be affected by acidic deposition) and soil enhancement. Any restoration action must also incorporate the acquisition of an interest in the restored lands sufficient to ensure perpetual protection of the restored land. Any proposal for acquisition of land must identify fully all owners of the interests in the land. Every proposal for acquisition of land must identify the ultimate holder of the interests to be acquired and provide a basis for concluding that the proposed holder of title is appropriate for long-term protection of the ecological or environmental benefits sought to be achieved through the acquisition.

2. Describe generally the ecological significance of the area to be acquired or restored. In particular, identify the environmental/ecological benefits expected as a result of the proposed action. In proposing areas for acquisition and restoration, Defendants shall focus on those areas that are in most need of conservation action or that promise the greatest conservation return on investment.

3. Describe the expected cost of the Land Acquisition and Restoration, including the fair market value of any areas to be acquired.

4. Identify any person or entity other than Defendants that will be involved in the land acquisition or restoration action. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the project.

C. Performance - Upon approval of the plan by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Land Acquisition and Restoration project according to the approved plan and schedule.

IV. Nitrogen Impact Mitigation in the Chesapeake Bay

A. Within 120 days of Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the mitigation of adverse impacts on the Chesapeake Bay associated with nitrogen ("Chesapeake Bay Mitigation Project"). Defendants shall spend no less than a total of $3 million in Project Dollars on the Chesapeake Bay Mitigation Project.

B. Defendant's proposed plan shall:

1. Describe proposed Project(s) that reduce nitrogen loading in the Chesapeake Bay or otherwise mitigate the adverse effects of nitrogen in the Chesapeake Bay. Projects that may be approved include, by way of illustration, creation of forested stream buffers on agricultural land or other land cover to establish a "buffer zone" to keep livestock out of the adjoining waterway and to filter runoff before it enters the waterway.

2. Describe generally the expected environmental benefit of the proposed Chesapeake Bay Mitigation Project. The key criteria for selection of components of the Project are the magnitude of the expected ecological/environmental benefit(s) in relation to the cost and the relative permanence of the expected benefit(s). Expected loadings benefits should be quantified to the extent practicable.

3. Describe the expected cost of each element of the Chesapeake Bay Mitigation Project, including the fair market value of any interests in land to be acquired.

4. Identify any person or entity other than Defendants that will be involved in any aspect of the Chesapeake Bay Mitigation Project. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the Project.

C. Performance - Upon approval of the plan for Chesapeake Bay Mitigation by EPA, Defendants shall complete the Project according to the approved plan and schedule.

V. Mobile Source Emission Reduction Projects

A. Within 120 days of the Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the completion of Projects to reduce emissions from Defendants' fleet of barge tugboats on the Ohio River, diesel trains at or near power plants, Defendants' fleet of motor vehicles in certain eastern states, and/or truck stops in certain eastern states ("Mobile Source Projects"). Defendants shall spend no less than a total of $21 million in Project Dollars on one or more of the three Mobile Source Projects specified in this Section, in accordance with the plans for such Projects approved by EPA, after consultation with the Citizen Plaintiffs. The key criteria for selection of components of the Mobile Source Projects are the magnitude of the expected environmental benefit(s) in relation to the cost.

B. Diesel Tug/Train Project

1. Defendants are among the leading barge operators in the country, with operations on the Ohio River, the Mississippi River, and the Gulf Coast. Barges are propelled by tugboats, which generally use a type of marine diesel fuel known as No. 2 distillate fuel oil. Tugboats that switch to ultra-low sulfur diesel fuel ("ULSD") reduce emissions of NO_X, PM, volatile organic compounds ("VOCs"), and other air pollutants. All marine diesel fuel must be ULSD by June 1, 2012, pursuant to EPA's Nonroad Diesel Rule (see "Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuels; Final Rule," 69 Fed. Reg. 38,958 (June 29, 2004)). Defendants also receive coal by diesel trains.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve accelerated emission reductions from their tugboat fleet on the Ohio River ("Ohio River Tug Fleet") and/or their diesel powered trains used at or near their power plants, as one of the three possible mobile source Projects under this Consent Decree ("Diesel Tug/Train Project").

3. The Diesel Tug/Train Project shall require one or more of the following:

a. The accelerated retrofitting or re-powering of Tugs with engines that require the use of ULSD. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

b. The retrofitting or repowering of the marine engines in the Ohio River Tug Fleet with diesel oxidation catalysts ("DOCs"), diesel particulate filters ("DPFs"), or other equivalent advanced technologies that reduce emissions of PM and VOCs from marine engines in tugboats (collectively "DOC/DPFs"). Defendants shall only install DOCs/DPFs that have received applicable approvals or verifications, if any, from the relevant regulatory agencies for reducing emissions from tugboat engines. Defendants must maintain any DOCs/DPFs installed as part of the Tug Project for the useful life of the equipment (as defined in the proposed Plan), even after the completion of the Tug Project. Project Dollars may be spent on DOCs/DPFs within 5 years of the Date of Entry, in accordance with the approved schedule for the mitigation projects in this Appendix.

c. The accelerated use of ULSD for the Ohio River Tug Fleet, from the Date of Entry through January 1, 2012. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit for the incremental cost of ULSD as compared to the cost of the fuel Defendants would otherwise utilize.

d. Emission reduction measures for diesel powered trains. Such measures may include retro-fitting with, or conversion to, Multiple Diesel Engine GenSets that are EPA Tier III Off-Road certified; Diesel Electric Hybrid; Anti-idling controls/strategies and Auto Shut-Off capabilities. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

4. The proposed plan for the Diesel Tug/Train Project shall:

a. Describe the expected cost of the project, including the costs for any equipment, material, labor costs, and the proposed method for accounting for the cost of each element of the Diesel Tug/Train Project, including the incremental cost of ULSD.

b. Describe generally the expected environmental benefit of the project, including any expected fuel efficiency improvements and quantify emission reductions expected.

c. Include a schedule for completing each portion of the Diesel Tug/Train Project.

5. Performance - Upon approval of the Diesel Tug/Train Project plan by EPA, Defendants shall complete the project according to the approved plan and schedule.

C. Hybrid Vehicle Fleet Project

1. AEP has a fleet of approximately 11,000 motor vehicles in the eleven states where it operates, including vehicles in Indiana, Ohio, Michigan, Virginia, West Virginia, and Kentucky. These motor vehicles are generally powered by conventional diesel or gasoline engines and include vehicles such as diesel "bucket" trucks. The use of hybrid engine technologies in Defendants' motor vehicles, such as diesel-electric engines, will improve fuel efficiency and reduce emissions of NO_X, PM, VOCs, and other air pollutants.

2. As part of the plan for Mobile Source Projects, Defendants may elect to spend Project Dollars on the replacement of conventional motor vehicles in their fleet with newly manufactured Hybrid Vehicles ("Hybrid Vehicle Fleet Project").

3. The proposed plan for the Hybrid Vehicle Fleet Project shall:

   a. Propose the replacement of conventional gasoline or diesel powered motor vehicles (such as bucket trucks) with Hybrid Vehicles. For purposes of this subsection of this Appendix, "Hybrid Vehicle" means a vehicle that can generate and utilize electric power to reduce the vehicle's consumption of fossil fuel. Any Hybrid Vehicle proposed for inclusion in the Hybrid Fleet Project shall meet all applicable engine standards, certifications, and/or verifications.

   b. Provide for Hybrid Vehicles replacement in that portion of Defendants' fleet in Indiana, Ohio, Michigan, West Virginia, Virginia, and/or Kentucky. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit toward Project Dollars for the incremental cost of Hybrid Vehicles as compared to the cost of a newly manufactured, similar motor vehicle.

   c. Prioritize the replacement of diesel-powered vehicles in Defendants' fleet.

   d. Provide a method to account for the costs of the Hybrid Vehicles, including the incremental costs of such vehicles as compared to conventional gasoline or diesel motor vehicles.

   e. Certify that Defendants will use the Hybrid Vehicles for their useful life (as defined in the proposed plan).

   f. Include a schedule for completing each portion of the Project.

g. Describe generally the expected environmental benefits of the Project, including any fuel efficiency improvements, and quantify emission reductions expected.

4. Performance - Upon approval by EPA of the plan for the Hybrid Vehicle Fleet Project, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

D. Truck Stop Electrification

1. Long-haul truck drivers typically idle their engines at night at rest areas to supply heat or cooling in their sleeper cab compartments, and to maintain vehicle battery charge while electrical appliances such as televisions, computers, and microwaves are in use. Modifications to rest areas to provide parking spaces with electrical power, heat, and air conditioning will allow truck drivers to turn their engines off. Truck stop electrification reduces idling time and therefore reduces diesel fuel usage, and thus reduces emissions of PM, NO_x, and VOCs.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve emission reductions by truck stop electrification, which shall include, where necessary, techniques and infrastructure needed to support such a program ("Truck Stop Electrification Project").

3. The proposed plan for the Truck Stop Electrification Project shall:

a. Identify truck stops in one or more of the following States for Electrification: Ohio, Indiana, Kentucky, North Carolina, Pennsylvania, West Virginia, and Virginia. EPA may give preference to electrification Projects that are co-located, if possible, along the same transportation corridor.

b. Describe the level of expected usage of the planned electrification facilities, air quality in the vicinity of the proposed Projects, proximity of the proposed Project to population centers, and whether the owner or some other entity is willing to pay for some portion of the work.

c. Provide for the construction of truck stop electrification stations with established technologies and equipment.

d. Account for hardware procurement and installation costs at the recipient truck stops.

e. Include a schedule for completing each portion of the Project.

f. Describe generally the expected environmental benefits of the Project and quantify emission reductions expected.

4. Performance - Upon approval of the plan for the Truck Stop Electrification Project by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

APPENDIX B

REPORTING REQUIREMENTS

I. Annual Reporting Requirements

In accordance with the dates specified below, for periods on and after the Date of Entry, Defendants shall submit annual reports to the United States, the States, and the Citizen Plaintiffs, electronically and in hard copy, as required by Paragraph 143 and certified as required by Paragraph 146. In such annual reports, Defendants shall include the following information:

A. Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x

Beginning on March 31, 2010, for the Eastern System-Wide Annual Tonnage Limitations for NO_x, and March 31, 2011, for the Eastern System-Wide Annual Tonnage Limitations for SO_2, and annually thereafter, Defendants shall report the following information: (a) the total actual annual tons of the pollutant emitted from each Unit (or for Units vented to a common stack, from each combined stack) within the AEP Eastern System, as defined in Paragraph 7, during the prior calendar year; (b) the total actual annual tons of the pollutant emitted from the AEP Eastern System during the prior calendar year; (c) the difference, if any, between the applicable Eastern System-Wide Annual Tonnage Limitation for the pollutant in that calendar year and the amount reported in subparagraph (b); and (d) the annual average emission rate, expressed as a lb/mmBTU for NO_x, for each Unit within the AEP Eastern System and for the entire AEP Eastern System during the prior calendar year. Data reported pursuant to this subsection shall be based upon the CEMS data submitted to the Clean Air Markets Division.

B. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Clinch River plant on an annual rolling average basis as defined in Paragraphs 47 and 88 for the prior calendar year; and (b) the applicable Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at the Clinch River plant for the prior calendar year. For calendar years other than 2010 and 2015, Defendants shall also report the 12-month rolling average emissions for each month.

C. Plant-Wide Tonnage Limitation for SO_2 at Kammer

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Kammer plant as specified in Paragraph 48 for the prior calendar year; and (b) the Plant-Wide Tonnage Limitation for SO_2 at the Kammer plant for that calendar year.

D. Reporting Requirements for Excess NO_x Allowances

1. Reporting Requirements for Unrestricted Excess NO_x Allowances

Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report the number of Unrestricted Excess NO_x Allowances available each year between 2009 through 2015, and how or whether such allowances were used so that Defendants account for each Unrestricted Excess NO_x Allowance for each year during 2009 through 2015. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Unrestricted Excess NO_x Allowances subject to surrender pursuant to Paragraph 75 and calculated pursuant to Paragraph 74, and (b) the total number of unused Unrestricted Excess NO_x Allowances that they surrendered.

2. Reporting Requirements for Restricted Excess NO_x Allowances

a. Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report: (a) the number of Restricted Excess NOx Allowances available each year between 2009 through 2015; (b) the actual emissions from any New and Newly Permitted Unit during each year; (c) the actual NOx emissions from the five natural gas plants listed in Paragraph 76 during each year; (d) the amount, if any, of Restricted Excess NOx Allowances that are not subject to surrender each year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; and (e) the difference between the cumulative total of Restricted Excess NO_x Allowances available from each year and any prior year and the actual emissions reported under (b) and (c), above, for that year and any Restricted Excess NO_x Allowances not subject to surrender reported under (d), above. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Restricted Excess NO_x Allowances subject to surrender calculated pursuant to Paragraphs 76 and 77, and (b) the total number of unused Restricted Excess NO_x Allowances that they surrendered.

b. No later than March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the number of Restricted Excess NO_x Allowances available in the prior year; (b) the actual emissions from any New and Newly Permitted Unit during such year; (c) the actual emissions from the five natural gas plants listed in Paragraph 76 during such year; (d) the amount, if any, of Restricted Excess NO_x Allowances that are not subject to surrender for such year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; (e) the number of Restricted Excess NO_x Allowances subject to surrender for such year calculated pursuant to Paragraphs 76 and 77; and (f) the total number of unused Restricted Excess NO_x Allowances that they surrendered for such year.

E. Reporting Requirements for Excess SO_2 Allowances

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the number of Excess SO_2 Allowances subject to surrender calculated pursuant to Paragraph 93, and (b) the total number of Excess SO_2 Allowances that they surrendered.

F. Continuous Operation of Pollution Controls required by Paragraphs 68, 69, 87, and 102

On March 31 of the year following Defendants' obligation pursuant to this Consent Decree to commence Continuous Operation of an SCR, FGD, ESP, or Additional NO_x Pollution Controls, Defendants shall report the date that they commenced Continuous Operation of each such pollution control as required by this Consent Decree. Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report, for any SCR, FGD, ESP, or Additional NO_x Pollution Controls required to Continuously Operate during that year, the duration of any period during which that pollution control did not Continuously Operate, including the specific dates and times that such pollution control did not operate, the reason why Defendants did not Continuously Operate such pollution control, and the measures taken to reduce emissions of the pollutant controlled by such pollution control.

G. Installation of SO_2 and NO_x Pollution Controls

Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report on the progress of construction of NO_x and SO_2 pollution controls required by this Consent Decree including: (1) if construction is not underway, any available information concerning the construction schedule, including the dates of any major contracts executed during the prior calendar year, and any major components delivered during the prior calendar year; (2) if construction is underway, the estimated percent of installation as of the end of the prior calendar year, the current estimated construction completion date, and a brief description of completion of significant milestones during the prior calendar year, including a narrative description of the current construction status (e.g. foundations completed, absorber installation proceeding all material on-site, new stack erection completed, etc.); and (3) once construction is complete, the dates the equipment was placed in service and any acceptance testing was performed during the prior calendar year.

H. Installation and Operation of PM CEMS

Beginning on March 31, 2013, for Cardinal Units 1 and 2 and a third Unit identified pursuant to Paragraph 110, and continuing annually thereafter for all periods of operation of PM CEMS as required by this Consent Decree, Defendants shall report the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour rolling average basis in electronic format for the prior calendar year, in accordance with Paragraph 107.

I. Other SO_2 Measures

Commencing in the first annual report Defendants submit pursuant to Paragraph 143, and continuing annually thereafter, Defendants shall submit all data necessary to determine Defendants' compliance with the annual average coal content specified in the table in Paragraph 90.

J. 1-Hour Average NO_x Emission Rate and 30-Day Rolling Average Emission Rates for SO_2 and NO_x

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with an applicable 1-Hour Average NO_x Emission Rate and/or 30-Day Rolling Average Emission Rate for SO_2 and NO_x, and continuing annually thereafter, Defendants shall report all 1-Hour Average Emission Rate results and/or 30-Day Rolling Average Emission Rate results to determine compliance with such emission rate, as defined in Paragraph 4 or 5, as appropriate. Defendants shall also report: (a) the date and time that the Unit initially combusts any fuel after shutdown; (b) the date and time after startup that the Unit is synchronized with a utility electric distribution system; (c) the date and time that the fire is extinguished in a Unit; and (d) for the fifth and subsequent Cold Start Up Period that occurs within any 30-Day period, the earlier of the date and time that is either (i) eight hours after the unit is synchronized with a utility electric distribution system, or (ii) the flue gas has reached the SCR operational temperature range specified by the catalyst manufacturer.

2. Within the first report that identifies a 1-Hour Average NO_x Emission Rate or 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 1-Hour Average NO_x Emission Rate and the 30-Day Rolling Average Emission Rate for SO_2 or NO_x for five (5) randomly selected days. If at any time Defendants change the methodology used in determining the 1-Hour Average NO_x Emission Rate or the 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall explain the change and the reason for using the new methodology.

K. 30-Day Rolling Average Removal Efficiency for SO_2

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with a 30-Day Rolling Average Removal Efficiency, and continuing annually thereafter, Defendants shall report all 30-Day Rolling Average Removal Efficiency results to determine compliance with such removal efficiency as defined in Paragraph 6 or, for Conesville Units 5 and 6, as specified in Appendix C.

2. Within the first report that identifies a 30-Day Rolling Average Removal Efficiency for SO_2, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 30-Day Rolling Average Removal Efficiency for five (5) randomly selected days. If

at any time Defendants change the methodology used in determining the 30-Day Rolling Average Removal Efficiency, Defendants shall explain the change and the reason for using the new methodology.

L. PM Emission Rates

Beginning on March 31, 2010, for Cardinal Units 1 and 2, and beginning on March 31, 2013 for Muskingum River Unit 5, and continuing annually thereafter, Defendants shall report the PM Emission Rate as defined in Paragraph 51, for Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. For all such Units, Defendants shall attach a copy of the executive summary and results of any stack test performed during the calendar year covered by the annual report.

M. Environmental Mitigation Projects

1. Mitigation Projects to be Conducted by the States

Defendants shall report the disbursement of funds as required in Paragraph 127 of the Consent Decree in the next annual progress report that Defendants submit pursuant to Paragraph 143 following such disbursement of funds.

2. Appendix A Projects

Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

N. Other Unit becoming an Improved Unit

If Defendants decide to make an Other Unit an Improved Unit, Defendants shall so state in the next annual progress report they submit pursuant to Paragraph 143 after making such decision, and comply with the reporting requirements specified in Section I.G of this Appendix and any other reporting or notice requirements in accordance with the Consent Decree.

II. Deviation Reports

Beginning March 31, 2008, and continuing annually thereafter, Defendants shall report a summary of all deviations from the requirements of the Consent Decree that occurred during the prior calendar year, identifying the date and time that the deviation occurred, the date and time the deviation was corrected, the cause and any corrective actions taken for each deviation, if necessary, and the date that the deviation was initially reported under Paragraph 145. In addition to any express requirements in Section I, above, or in the Consent Decree, such deviations required to be reported include, but are not limited to, the following requirements: the 1-Hour Average NO_x Emission Rate, the

30-Day Rolling Average Emission Rates for SO_2 and NO_x, the 30-Day Rolling Average Removal Efficiency for SO_2, and the PM Emission Rate.

III. Submissions Pending Review

In each annual report Defendants submit pursuant to Paragraph 143, Defendants shall include a list of all plans or submissions made pursuant to this Consent Decree during the calendar year covered by the annual report, the date(s) such plans or submissions were submitted to one or more Plaintiffs for review and/or approval, and shall identify which, if any, are still pending review and approval by Plaintiffs upon the date of submission of the annual report.

IV. Other Information Necessary To Determine Compliance

To the extent that information not expressly identified above is necessary to determine Defendants' compliance with the requirements of this Consent Decree during a reporting period, and has not otherwise been submitted in accordance with the provisions of the Consent Decree, Defendants shall provide such information as part of the annual report required pursuant to Section XI of the Consent Decree.

APPENDIX C

MONITORING STRATEGY AND CALCULATION OF THE 30-DAY ROLLING AVERAGE REMOVAL EFFICIENCY FOR CONESVILLE UNITS 5 AND 6

I. Monitoring Strategy

1. The SO_2 monitoring system for Conesville Units 5 & 6 will consist of two separate FGD inlet monitors in each of the two FGD inlet ducts for each Unit, and one FGD outlet monitor in the combined flow from the outlets of the FGD modules for each Unit, prior to the common stack.

2. Due to space constraints and potential interferences, monitors are currently located in the inlet duct for one FGD module on each Unit and at the combined outlet from both FGD modules for each Unit prior to entering the stack using best engineering judgment.

3. On or before December 31, 2008, Defendants shall submit a monitoring plan to EPA for approval that will propose where to site and install an additional inlet monitor in each of the unmonitored FGD inlet ducts for each Unit, and include a requirement that Defendants submit a complete certification application for the Conesville Units 5 & 6 monitoring system to EPA and the state permitting authority.

4. The Monitoring Plan will incorporate the applicable procedures and quality assurance testing found in 40 C.F.R. Part 75, subject to the following:

   a. The PS-2 siting criteria will not be applied to these monitoring systems; however, the majority of the procedures in Section 8.1.3.2 of PS-2 will be followed. Sampling of at least nine (9) sampling points selected in accordance with PS-1 will be performed prior to the initial RATA. If the resultant SO_2 emission rates for any single sampling point calculated in accordance with Equation 19.7 are all within 10% or 0.02 lb/mmBtu of the mean of all nine (9) sampling points, the alternative traverse point locations (0.4, 1.2, and 2.0 meters from the duct wall) will be representative and may be used for all subsequent RATAs.

   b. The required relative accuracy test audit will be performed in accordance with the procedures of 40 C.F.R. Part 75, except that the calculations will be performed on an SO_2 emission rate basis (i.e., lb/mmBtu).

   c. The criteria for passing the relative accuracy test audit will be the same criteria that 40 C.F.R. Part 75 requires for relative accuracy or alternative performance specification as provided for NO_x emission rates.

d. "Diluent capping" (i.e., 5% CO_2) will be applied to the SO_2 emission rate for any hours where the measured CO_2 concentration rounds to zero.

e. Results of quality assurance testing, data gathered by the inlet and outlet monitoring systems, and the resultant 30-day Rolling Average Removal Efficiencies for these monitoring systems are not required to be reported in the quarterly reports submitted to EPA's Clean Air Markets Division for purposes of 40 C.F.R. Part 75. Results will be maintained at the facility and available for inspection, and the 30-day Rolling Average Removal Efficiency will be reported in accordance with the requirements of the Consent Decree and Appendix B. Equivalent data retention and reporting requirements will be incorporated into the applicable permits for these Units.

f. Missing Data Substitution of 40 C.F.R Part 75 will not be implemented.

g. Initial performance testing will be performed before the effective date of the 30-Day Rolling Average Removal Efficiency requirements, and the results will be reported to Plaintiffs as part of the annual report submitted in accordance with Appendix B.

II. Calculation of 30-Day Rolling Average Removal Efficiency

1. Removal efficiency shall be calculated by the equation:

$$[SO_2 \text{ emission rate}_{Inlet} - SO_2 \text{ emission rate}_{Outlet}] / SO_2 \text{ emission rate}_{Inlet} * 100$$

2. Inlet and outlet emission rates shall be calculated using the methodology specified in 40 C.F.R. Part 60 Appendix B – Method 19. Inlet emission rates will be based on the average of the valid recorded values calculated for each of the inlet FGD monitors at each Unit. Measurements are made on a wet basis, so Equation 19.7 will be utilized to determine the hourly SO_2 emission rate at each location. To make the conversion between the measured wet SO_2 and CO_2 concentrations and an emission rate in pounds per million BTU, an electronic Data System will perform Equation 19.7 using the SO_2 ppm conversion factor from Table 19-1 of Method 19 and the Fc factor for the applicable fuel (currently bituminous coal) in Table 19-2 of Method 19. The resulting equation will be:

$$\text{Emission rate (lb } SO_2/\text{mmBtu)} = 1.660 \times 10^{-7} * SO_2 \text{ (in ppm)} * Fc * 100 / CO_2 \text{ (in \%)}$$

3. The electronic data system will calculate the hourly average SO_2 and CO_2 concentration in accordance with 40 C.F.R. Part 75 quality control/quality assurance requirements and will compute and retain these SO_2 emission rates for every operating hour meeting the minimum data capture requirements in accordance with 40 C.F.R. Part 75. Prior to the

calculation of the SO_2 emission rate, hourly SO_2 and CO_2 concentrations will be rounded to the nearest tenth (i.e., 0.1 ppm or 0.1 % CO_2) and the resulting SO_2 emission rate will be rounded to the nearest thousandth (i.e., 0.001 lb/mmBtu).

4. From these hourly SO_2 emission rates, SO_2 removal efficiencies will be calculated for each hour when the Unit is firing fossil fuel, and the hourly SO_2 and CO_2 monitors meet the QA/QC requirements of Part 75. Hourly SO_2 removal efficiencies will be computed by taking the hourly inlet SO_2 emission rate minus the outlet SO_2 emission rate, dividing the result by inlet SO_2 emission rate and multiplying by 100. The resulting removal efficiency will be rounded to the nearest tenth (i.e., 95.1%). Daily SO_2 removal efficiencies will be calculated by taking the sum of Hourly SO_2 removal efficiencies and dividing by the number of valid monitored hours for each Operating Day. The resulting daily removal efficiencies will be rounded to the nearest tenth (i.e., 95.1%).

5. The 30-Day Rolling Average Removal Efficiency will be computed by taking the current Operating Day's daily SO_2 removal efficiency (as described in Paragraph 4 of this Appendix C) plus the previous 29 Operating Days' daily SO_2 removal efficiency, and dividing the sum by 30. In the event that a daily SO_2 removal efficiency is not available for an Operating Day, Defendants shall exclude that Operating Day from the calculation of the 30-Day Rolling Average Removal Efficiency. The resulting 30-day Rolling Average Removal Efficiency will be rounded to the nearest tenth of a percent (i.e., a value of 95.04% rounds down to 95.0%, and a value of 95.05% rounds up to 95.1%).

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King Civil Action No. C2-05-360 Civil Action No. C2-04-1098

ORDER ENTERING THIRD JOINT MODIFICATION TO CONSENT DECREE

This matter is before the Court on Plaintiff the United States of America's Motion to Approve the Third Joint Modification of the Consent Decree. (Doc. No. 547.) For the reasons set forth within Plaintiff's motion, the Court **GRANTS** the motion and **ENTERS** the Third Joint Modification to Consent Decree, which is attached hereto.

This Order renders moot Defendants' Application for Judicial Interpretation of the Consent Decree (Doc. No. 528) and Defendants' Motion to Strike (Doc. No. 539). These two motions are therefore **DENIED AS MOOT**.

IT IS SO ORDERED this 14th day of MAY, 2013.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

THIRD JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on April 5, 2010 (Case No. 99-1250, Docket # 371), and as modified by a second Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on December 28, 2010 (Case No. 99-1250, Docket # 372), the Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) no later than December 31, 2015 on Big Sandy Unit 2, December 31, 2015 on Muskingum River Unit 5, December 31, 2017 on Rockport Unit 1, and December 31, 2019 on Rockport Unit 2.

WHEREAS, on October 31, 2012, the Defendants filed an Application for Judicial Interpretation of Consent Decree in Case No. 99-1182 (Docket # 528) and the related cases.

WHEREAS, the United States, the States and Citizen Plaintiffs filed a Memorandum in Opposition (Case No. 99-1182, Docket # 534), and Citizen Plaintiffs filed a Supplemental Memorandum in Opposition (Case No. 99-1250, Docket # 381) to the Defendants' Application.

WHEREAS all Parties made additional filings and the Application was scheduled for a hearing on December 17, 2012.

WHEREAS, the Parties have engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Third Joint Modification finds, that this Third Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq*.; and that entry of this Third Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Third Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Third Joint Modification in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Third Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Third Joint Modification by this Court or challenge any provision of this Third Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Third Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Application or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

1. Add a definition of "Cease Burning Coal" as new Paragraph 8A of the Consent Decree as follows:

8A. "Cease Burning Coal" means that Defendants shall permanently cease burning coal for purposes of generating electricity from a Unit, and shall submit all necessary notifications or requests for permit amendments to reflect the permanent cessation of coal firing at the Unit.

2. Modify the definition of "Continuously Operate" in Paragraph 14 of the Consent Decree as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, ESP, or Other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

3. Add a new definition of "Dry Sorbent Injection" or "DSI" as new Paragraph18A of the Consent Decree as follows:

18A. "Dry Sorbent Injection" or "DSI" means a pollution control system in which a sorbent is injected into the flue gas path prior to the particulate pollution control device for the purpose of reducing SO_2 emissions. For purposes of the DSI systems required to be installed at the Rockport Units only, the DSI systems shall utilize a sodium based sorbent and be designed to inject at least 10 tons per hour of a sodium based sorbent. Defendants may utilize a different sorbent at the Rockport Units provided they obtain prior approval from Plaintiffs pursuant to Paragraph 148 of the Consent Decree.

4. Modify the definition of "Improved Unit" in Paragraph 28 of the Consent Decree as follows:

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, Re-Powered, or Refueled.

The remainder of Paragraph 28 shall remain the same.

5. Add a definition of "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" as new Paragraph 48A of the Consent Decree, as follows:

48A. "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" means the sum of the tons of SO_2 emitted during all periods of operation from the Rockport Plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (*i.e.*, January 1 – December 31).

6. Add a definition of "Refuel" as new Paragraph 53A of the Consent Decree, as follows:

53A. "Refuel" means, solely for purposes of this Consent Decree, the modification of a unit as necessary such that the modified unit generates electricity solely through the combustion of natural gas rather than coal, including the installation and Continuous Operation of the NO_x controls required by Section IV of this Consent Decree. Nothing herein shall prevent the reuse of any equipment at any existing unit or new emissions unit, provided that AEP applies for, and obtains, all required permits, including, if applicable, a PSD or Nonattainment NSR permit.

7. Modify the definition of "Retrofit" in Paragraph 56 of the Consent Decree as follows:

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD, as defined in the Consent Decree. For purposes of the requirements in Paragraph 87 for the Rockport Units, "Retrofit" also means that the Unit will be equipped with a post-combustion wet- or dry-FGD system with a control technology vendor guaranteed design removal efficiency of 98% or more, and subject upon installation to a 30-Day Rolling Average Emissions Rate of 0.100 lb/mmBTU for SO_2, if the Unit burns coal with an uncontrolled SO_2 emissions rate of 3.0 lb/mmBTU or higher, or a 30-day Rolling Average Emission Rate of 0.060 lb/mmBTU if the

Unit burns coal with an uncontrolled SO_2 emissions rate below 3.0 lb/mmBTU. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NOx and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO2, measured in accordance with the requirements of this Consent Decree.

8. Modify the Eastern System-Wide Annual Tonnage Limitations for SO_2 in the table in Paragraph 86 of the Consent Decree as follows:

86. Notwithstanding any other provision of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year(s)	**Eastern System-Wide Annual Tonnage Limitations for SO_2**	**Modified Eastern System-Wide Annual Tonnage Limitations for SO_2**
2016	~~260,000 tons~~	145,000 tons
2017	~~235,000 tons~~	145,000 tons
2018	~~184,000 tons~~	145,000 tons
2019~~, and each year thereafter~~ - 2021	~~174,000 tons~~	113,000 tons per year
2022 - 2025	~~174,000 tons~~	110,000 tons per year
2026 - 2028	~~174,000 tons~~	102,000 tons per year
2029, and each year thereafter	~~174,000 tons~~	94,000 tons per year

The remainder of the table in Paragraph 86 shall remain the same.

9. Modify the SO_2 pollution control requirements and compliance dates listed in the

table in Paragraph 87 of the Consent Decree for Big Sandy Unit 2, Muskingum River Unit 5, Rockport Units 1 and 2, and Tanners Creek Unit 4 as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, ~~or~~ Re-power, or Refuel such Unit:

Unit	**SO_2 Pollution Control**	**Modified SO_2 Pollution Control**	**Date**	**Modified Date**
Big Sandy Unit 2	~~FGD~~	Retrofit, Retire, Re-power, or Refuel	December 31, 2015	NA
Muskingum River Unit 5	~~FGD~~	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	~~December 31, 2015~~	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the unit will be taken out of service no later than December 31, 2015 and will not restart until the Refueling project is completed. The Refueling project must be completed by June 30, 2017.
First Rockport Unit	~~FGD~~	Dry Sorbent Injection, and Retrofit, Retire, Re-power, or Refuel	~~December 31, 2017~~	April 16, 2015 December 31, 2025.
Second Rockport Unit	~~FGD~~	Dry Sorbent Injection, and	~~December 31, 2019~~	April 16, 2015 and

Unit	SO_2 Pollution Control	Modified SO_2 Pollution Control	Date	Modified Date
		Retrofit, Retire, Re-power, or Refuel		December 31, 2028.
Tanners Creek Unit 4	NA	Retire or Refuel	NA	June 1, 2015

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same, including the Joint Modifications previously made to the compliance deadlines for Amos Units 1 and 2.

10. Add a new Paragraph 89A establishing the Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport, as follows:

89A. For each of the calendar years set forth in the table below, Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to Plant-Wide Annual Tonnage Limitations for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitations for SO_2
2016 - 2017	28,000 tons per year
2018 - 2019	26,000 tons per year
2020 - 2025	22,000 tons per year
2026 - 2028	18,000 tons per year
2029, and each year thereafter	10,000 tons per year

11. Modify Paragraph 92 of the Consent Decree as follows:

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirements of this

Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitation, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, or Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emission above the limits specified in this Consent Decree.

12. Modify Paragraph 100 of the Consent Decree as follows:

100. To the extent an Emission Rate, 30-Day Rolling Average Removal Efficiency, Eastern System-Wide Annual Tonnage Limitation, or Plant-Wide Annual Tonnage Limitation for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine the Emission Rate or annual emissions.

13. Modify Paragraph 104 of the Consent Decree as follows:

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the performance testing requirements for Muskingum River Unit 5 contained in this Paragraph.

14. Modify Paragraph 105 of the Consent Decree as follows:

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the stack testing requirements for Muskingum River Unit 5 contained in this Paragraph.

15. Modify Paragraph 119 of the Consent Decree as follows:

119. Defendants shall implement the Environmental Mitigation Projects described in Appendix A to this Consent Decree, shall fund the categories of Projects described in Subsection B, below, and shall implement the Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects described in Subsection C, below, (collectively, the "Projects") in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree.

The remainder of Paragraph 119 shall remain the same.

16. Add a new Subsection C after Paragraph 128 of the Consent Decree as follows:

C. Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects.

128A. Citizen Plaintiffs' Renewable Energy Project. Defendants shall implement a renewable energy project as described below during the period from 2013 through 2019.

a. If, during the period from 2013-2015, a renewable energy production tax credit of at least 2.2 cents/kwh for ten years is available for new wind electricity production facilities upon which construction is commenced within one year or more after enactment of the tax credit (or an alternative tax benefit is available that provides sufficient economic value so that the levelized cost to customers does not exceed the weighted average cost of any existing contracts with Indiana Michigan Power Company ("I&M") for 50 MW or greater of wind capacity, adjusted for inflation) I&M will secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment. For the avoidance of doubt, so long as the energy production tax credit contained in the American Taxpayer Relief Act of 2012 allows projects that have commenced construction by December 31, 2013, and that are placed in service by December 31, 2014, to qualify for the energy production tax credit provided in that Act, then I&M shall be obligated to secure new renewable energy purchase agreements for 200 MW of new wind energy capacity.

b. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during 2013-2015, but becomes available during 2016-2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M will use commercially reasonable efforts to secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment.

c. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during the period from 2013 – 2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M shall be relieved of its obligations to secure new wind energy capacity under this Paragraph 119A.

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

17. Modify Paragraph 127 of the Consent Decree as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional

amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

18. Modify Paragraph 133 of the Consent Decree as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or, solely for the first Rockport Unit, before December 31, 2025, or, solely for the second Rockport Unit, before December 31, 2028, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The remainder of Paragraph 133 shall remain the same.

19. Modify the table in Paragraph 150 of the Consent Decree as follows:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
x. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport	\$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
y. Failure to fund a Citizen Plaintiffs' Mitigation Project as required by Paragraph 119B of this Consent Decree	\$1,000 per day per violation during the first 30 days, \$5,000 per day per violation thereafter
z. Failure to implement the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 128A of this Consent Decree	\$10,000 per day per violation during the first 30 days, \$32,500 per day per violation thereafter

The remainder of the table in Paragraph 150 shall remain the same.

20. In addition to the requirements reflected in Appendix B (Reporting Requirements) to the Consent Decree, Defendants shall include in their Annual Report to Plaintiffs the following information:

O. Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport

Beginning on March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 – 2028, Defendants shall report the daily average SO_2 emissions from the Rockport Plant expressed in lb/mmBTU, and the daily sorbent deliveries to the Rockport Plant by weight.

P. Citizen Plaintiffs' Renewable Energy Project

Beginning on March 31, 2014, and continuing each year thereafter until completion of the Citizen Plaintiffs' Renewable Energy Project, Defendants shall include a written report detailing the progress of the implementation of the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 119A of the Consent Decree.

Q. Citizen Plaintiffs' Mitigation Projects

Beginning on March 31, 2013, and continuing each year until March 31, 2015, Defendants shall include a written report detailing the progress of implementation of the Citizen

Plaintiffs' Mitigation Projects required by Paragraph 119B of the Consent Decree.

R. By March 31, 2015, Defendants shall notify Plaintiffs of their intent to Retire or Refuel Muskingum River 5.

S. By March 31, 2024, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-Power or Refuel the first Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

T. By March 31, 2027, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-power or Refuel the second Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

U. If Defendants elect to Retrofit one or both of the Rockport Units, beginning in the annual reports submitted for calendar years 2026 and/or 2029, as applicable, Defendants shall report a 30-Day Rolling Average SO_2 Emission Rate for the Unit(s) that is (are) Retrofit in accordance with Paragraph 5 of the Consent Decree. In addition, Defendants shall report a 30-Day Rolling Average Uncontrolled Emission Rate for SO_2 for the Unit(s) that is(are) Retrofit based on daily as burned coal sampling and analysis or an inlet SO_2 CEMs upstream of the FGD.

The remainder of Appendix B shall remain the same.

21. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 14th DAY OF May, 2013.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA:

Ignacia S. Moreno

IGNACIA S. MORENO
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

Myles E. Flint by BAW w/ permission

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FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA[1], NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION AND LEAGUE OF OHIO SPORTSMEN:

Faith E. Bugel

FAITH BUGEL
Environmental Law and Policy Center
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Chicago, Illinois 60601-2110

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[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

LOCAL COUNSEL FOR SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, INC., OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA[1], NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION AND LEAGUE OF OHIO SPORTSMEN:

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[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:

David Feinberg

DAVID M. FEINBERG
General Counsel
American Electric Power Service Corporation
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Columbus, Ohio 43215

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

ZACHARY C. MILLER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Zachary C Miller, being duly sworn, deposes and says he is a Corporate Finance Analyst Principal for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Zachary C Miller

STATE OF OHIO	)	
	)	CASE NO. 2017-00179
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Zachary C Miller, this the 20th day of June 2017.

NOTARIAL SEAL STATE OF OHIO

JOSEPHINE M. CONER
Notary Public, State of Ohio
My Commission Expires 10-10-2021

Josephine M. Coner

Notary Public

My Commission Expires: 10-10-2021

DIRECT TESTIMONY OF
ZACHARY C. MILLER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

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DIRECT TESTIMONY OF
ZACHARY C. MILLER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Zachary C. Miller. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation ("AEPSC") as a Principal Corporate Finance Analyst. AEPSC, a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Kentucky Power Company ("Kentucky Power" or "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Business Administration as an Accounting major from The Ohio State University in 2009. I earned a Master of Business Administration from Capital University in 2013.

I began employment with AEPSC as a Treasury Analyst in June 2009. Between June 2009 and January 2013, I worked in various capacities, with primary focus on cash and deal management operations within the Treasury Department. In February 2013, I transferred to the Corporate Finance group as an Analyst. In March 2016, I was promoted to my current position of Principal Corporate Finance Analyst.

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRINCIPAL CORPORATE FINANCE ANALYST?

A. My responsibilities include planning and executing the corporate finance programs of the regulated operating companies in the AEP System, including Kentucky Power. I am also responsible for preparing dividend payment recommendations for the companies in the AEP System, establishing capitalization targets, and managing the relationships between AEP and its subsidiaries with the credit rating agencies.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support certain historical and adjusted data incorporated in this application. I will sponsor Kentucky Power Company's proposed capital structure and cost of capital for ratemaking purposes, employing the cost of common equity, supported by Company Witness McKenzie.

Q. **ARE YOU SPONSORING ANY SCHEDULES INCLUDED IN THE COMPANY'S FILING?**

A. Yes. I am sponsoring the following Section V Schedules and Workpapers:

- Section V Workpaper S-2 Page 1 – Cost of Capital
- Section V Schedule 3 (Column 3, Lines 1-4) – Capitalization
- Section V Workpaper S-3 Page 1 – Long-Term Debt
- Section V Workpaper S-3 Page 2 – Schedule of Short-Term Debt

Q. **WERE THE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A. Yes.

IV. PROPOSED COST OF CAPITAL AND CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE KENTUCKY POWER'S PROPOSED CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL?

A. Based the test year ended February 28, 2017, Kentucky Power's proposed capital structure and weighted average cost of capital is summarized in Table 1 below.

Table 1

Description	Reapportioned Kentucky Jurisdictional Capital	Percentage of Total	Annual Cost Percentage Rate	Weighted Average Cost Percent
Long Term Debt	$648,913,758	54.45%	5.32%	2.90%
Short Term Debt	0	0.00%	0.80%	0.00%
Accounts Receivable Financing	46,105,009	3.87%	1.95%	0.08%
Common Equity	496,766,726	41.68%	**10.31%**	4.30%
Total	$1,191,785,493	100.00%		**7.28%**

Q. HOW WAS THE COMPANY'S PROPOSED CAPITAL STRUCTURE DEVELOPED?

Development of the proposed capital structure, as shown in Table 1, begins with the per book balances for each category of capital as of the end of the test year, February 28th, 2017. The per book balances are then adjusted to account for known and measurable changes to the Company's capitalization. The capitalization adjustments are shown in Section V, Schedule 3 and detailed in the testimonies of Company Witnesses Wohnhas and Ross.

Q. PLEASE EXPLAIN HOW THE PROPOSED WEIGHTED AVERAGE COST OF CAPITAL OF 7.28% WAS CALCULATED.

A. The proposed weighted average cost of capital is based on the summation of the weighted average cost for each source of capital in the Company's capital structure, including long-term debt, short-term debt, common stock, accounts receivable financing, and the treatment of investment tax credits. The calculation is shown on Section V, Workpaper S-2 page 1. The Company began with the Reapportioned Kentucky Jurisdictional capitalization as calculated on Section V Schedule 3 Column 14 for each source of capital. Next, the Company divided the dollar amount of each component of capital by the Company's total dollar amount of capital to derive the percentage of the Company's total capital each component represents. The percentage of total capital was then multiplied by the respective annual cost percentage rate for each source of capital.

Q. PLEASE EXPLAIN WHAT RATES WERE USED IN CALCULATING THE COMPANY'S PER BOOKS WEIGHTED AVERAGE COST OF CAPITAL AS OF FEBRUARY 28, 2017.

A. The weighted cost of long-term debt was determined by taking the sum of each debt instrument's actual annualized cost and dividing this amount by the total debt outstanding as of February 28, 2017. The annualized cost for each debt instrument was calculated by multiplying the effective cost rate (yield to maturity) by the net proceeds outstanding. The effective cost rate, or yield to maturity, is the debt yield expressed as an annual rate in relation to the face value of the instrument. As such, the annualized cost is calculated by multiplying the yield to maturity by the current amount outstanding. The sum of the annualized costs is then divided by the total debt outstanding to determine the weighted cost of the long-term debt portfolio. Please refer to Section V, Workpaper S-3, page 1.

The cost of short-term debt used in the calculation is the Company's actual short-term interest expense for the twelve months ended February 28, 2017 divided by the actual average borrowings outstanding during the same time period. Please refer to Section V, Workpaper S-3, page 2.

The cost of accounts receivable financing used in the derivation of the weighted average cost of capital was calculated using the thirteen month average cost of receivable factoring experienced by the Company during the test year.

The cost of common equity used in the calculation is recommended by Company Witness McKenzie.

Q. PLEASE DESCRIBE THE CHANGE IN THE WEIGHTED AVERAGE COST OF LONG-TERM DEBT SINCE THE COMPANY'S LAST BASE RATE CASE.

A. The Company's weighted average cost of long-term debt is 5.32% which is 9 basis points lower than the weighted average cost of long term debt of 5.41% at the time of the Company's application in Case No. 2014-00396.

V. FINANCIAL POSITIONING

Q. PLEASE BRIEFLY EXPLAIN HOW THE COMPANY FINANCES ITS OPERATIONS?

A. The Company generally finances its operations (construction program and working capital requirements) from one of two sources of available capital: internally-generated funds and externally-generated funds. Internally-generated funds are cash receipts the Company collects from its customers netted for cash expenses. Conversely, externally-generated funds include money accessed through capital markets. When the Company's internally generated funds are not sufficient to cover operations or investments, the Company accesses capital markets to finance its operations and fund its investment.

Q. DOES THE COMPANY PLAN TO ACCESS CAPITAL MARKETS TO FINANCE UPCOMING OPERATIONS AND INVESTMENT?

A. Yes. Kentucky Power's financing plans were detailed in the Commission's December 21, 2016 Order in Case No. 2016-00345 granting the Company's application for financing authority. Kentucky Power was granted authority to issue indebtedness and engage in financings in an amount of up to $85,000,000 for its general corporate purposes and its capital requirements. Additionally and included in the granted financing authority, the Company will refinance the $325,000,000 6.0% Senior Note, Series E, due September 2017, the $75,000,000 Variable Rate Local Bank Facility Program due November 2018 and the $65,000,000 WVEDA Mitchell Project, Series 2014A Variable Rate Demand Note Pollution Control Bond due June 2017.

Q. WHEN DOES THE COMPANY EXPECT TO ACCESS CAPITAL MARKETS?

A. The Company expects to refinance the $325,000,000 6.0% Senior Note, Series E and the $65,000,000 WVEDA Mitchell Project, Series 2014A Variable Rate Demand Note in June 2017. Kentucky Power expects to renew the Variable Rate Local Bank Facility Program at its maturity in November 2018. The Company will continue to evaluate the need and timing of the amount of up to $85,000,000 for its general corporate purposes and its capital requirements.

Q. WHAT IMPACT WILL THE DEBT REFINANCING HAVE ON KENTUCKY POWER'S WEIGHTED AVERAGE COST OF CAPITAL?

A. The specific impact the debt refinancing will have on the Company's weighted average cost of capital cannot be known until the refinancing transactions are complete. Upon completion of the Senior Note and Pollution Control Bond debt refinancing transactions, the Company will submit supplemental testimony detailing the terms and conditions of the new debt offerings.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	**Case No. 2017-00179**

DIRECT TESTIMONY OF

DEBRA L. OSBORNE

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Debra L Osborne, being duly sworn, deposes and says she is Vice President Generating Assets APCO/KY, that she has personal knowledge of the matters set forth in the testimony for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief.

Debra L Osborne

Debra L. Osborne

STATE OF WEST VIRGINIA)
) Case No. 2017-00179
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Debra L. Osborne, this the 19th day of June 2017.

Maisha T. Staples

Notary Public

Notary ID Number: ______________

My Commission Expires: November 23, 2021

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
Maisha T. Staples
Appalachian Power
500 Lee St. E. Laidley Tower, Suite 800
Charleston, WV 25301
My Commission Expires November 23, 2021

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

CASE NO. 2017-00179

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

I. INTRODUCTION AND BACKGROUND

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

A. My name is Debra L. Osborne. My business address is 500 Lee Street East, Charleston, WV, 25301. I am Vice President of Generating Assets for Appalachian Power Company ("Appalachian Power") and Kentucky Power Company ("Kentucky Power" or "Company"). Appalachian Power and Kentucky Power are wholly-owned subsidiaries of American Electric Power Company, Inc. ("AEP")

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

A. I earned a Bachelor of Science degree in Electrical Engineering from West Virginia University and have completed both a Leadership Development program at The Ohio State University Fisher College of Business and a Utility Management Certification from Willamette University. I joined Ohio Power Company in 1987 as a performance engineer at Gavin Plant, progressing to various positions until I transferred to Appalachian Power's Philip Sporn Plant as Energy Production Manager. Since 2005, I have been Plant Manager at four of Appalachian Power's coal-fired plants and the AEP Simulator Learning Center. I assumed my current position as Vice President Generating Assets for Appalachian Power and Kentucky Power in January 2017.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT OF GENERATING ASSETS FOR APPALACHIAN POWER AND KENTUCKY POWER.

A. I am responsible for the safe, reliable and economic operation of the fossil-fueled generating assets owned and operated by Kentucky Power and Appalachian Power. Specifically, I plan, organize, coordinate, direct and control plant activities, including the operations, maintenance, engineering and construction of the plant facilities. I also oversee plant budgets and interface with other AEP functional groups such as accounting, regulatory, and commercial operations to ensure the needs of the generating plants are met.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE WITH SELECTIVE CATALYTIC REDUCTION (“SCR”) SYSTEMS.

A. I have worked at two AEP coal plants operating with installed SCR systems, including serving as the Plant Manager for the 1,320 megawatt (“MW”) Mountaineer Plant. I am familiar with the activities, consumables, costs, and maintenance required to operate an SCR.

II. PURPOSE OF DIRECT TESTIMONY

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

A. The purpose of my testimony is to:

- Describe the Kentucky Power generation assets.
- Describe the Big Sandy Unit 1 natural gas conversion process.
- Provide an update on decommissing activities for Big Sandy Unit 2.

- Describe and support the reasonableness of Kentucky Power's generation non-fuel, non-labor operations and maintenance ("O&M") expenses for Mitchell and Big Sandy Plants.
- Support the reasonableness and cost-effectiveness of the Rockport Unit 1 SCR Project included in the Company's 2017 Environmental Compliance Plan.

III. KENTUCKY POWER'S GENERATING ASSETS

Q. PLEASE DESCRIBE KENTUCKY POWER'S GENERATION ASSETS.

A. Kentucky Power's generation assets consist of both owned and contracted generation capacity for a total of 1458 MW.

Q. PLEASE BRIEFLY DESCRIBE KENTUCKY POWER'S OWNED GENERATION.

A. Kentucky Power's generation assets consist of a total of 1065 MW of capacity from two generating plants, Big Sandy and Mitchell. The Company's assets and their characteristics are listed in Table 1.

Table 1: Kentucky Power Generation Assets

Plant	Kentucky Power-Owned Capacity(MW)	No. of Units	Location	Fuel	Expected Retirement Date
Big Sandy	285	1	Louisa, KY	Natural Gas	2031
Mitchell	780	2	Moundsville, WV	Coal	2040

Kentucky Power owns and operates the Big Sandy Plant located near Louisa, Kentucky. The plant currently is a single unit with a generating capacity of 285 MW. Big Sandy Unit 1 was originally placed in service in 1963 and operated as a 278 MW sub-critical coal-fired generating unit through mid-November 2015. As approved by the Commission in Case No. 2013-00430, and described later in my testimony, Big Sandy Unit 1 was converted to a natural gas-fired unit and returned to service May 31, 2016. The unit is equipped with low

NOx burners with overfire air for reduction of nitrogen oxides (“NOx”) emissions. The Company retired Big Sandy Unit 2, an 800 MW coal-fired generating unit, on May 31, 2015.

The Mitchell Plant is located approximately 12 miles south of Moundsville, West Virginia on the Ohio River. Kentucky Power owns an undivided 50% interest in the Mitchell Plant; the other 50% interest is owned by Wheeling Power Company. The plant comprises two super-critical pulverized coal-fired base load generating units. Mitchell Unit 1 has a capacity of 770 MW and Mitchell Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW. Both units were placed in service in 1971. Each unit is equipped with an Electrostatic Precipitator (“ESP”) for control of particulate, a Flue Gas Desulfurization system for sulfur dioxide (“SO_2”) control, and both SCR technology and low-NO_x burners for control of NO_x emissions. Both units also utilize a dry fly ash handling system.

Q. PLEASE DESCRIBE WHAT COMPRISES KENTUCKY POWER’S CONTRACTED GENERATION.

A. Kentucky Power is a party to a unit power agreement with AEP Generating Company for power from the Rockport Plant. The Rockport Plant is located along the Ohio River in southern Indiana and consists of two supercritical pulverized coal-fired generating units. Kentucky Power’s contractual share of the Rockport output totals 393 MW.

Q. HAVE THE RETIREMENT DATES FOR THE MITCHELL OR BIG SANDY GENERATING UNITS CHANGED?

A. No. The expected life of a power plant depends on many factors, including the original design, the current condition of the unit, and the potential cost to replace the generation with another source. There have been no changes to either unit at the Mitchell plant that indicate a change in the retirement date of 2040. The 2031 retirement date is still a valid expectation of the useful life of Big Sandy Unit 1.

IV. BIG SANDY UNIT 1 CONVERSION

Q. WHAT MODIFICATIONS WERE MADE TO CONVERT BIG SANDY UNIT 1 FROM A COAL-FIRED TO A GAS-FIRED UNIT?

A. Major unit modifications required to convert Big Sandy Unit 1 included changes to the existing steam generator (boiler) and unit control systems to accommodate the combustion of natural gas, the installation of new fuel metering and regulating facilities for the natural gas, and modifications to the associated balance of plant systems. Additional work included:

- Modifications to the boiler pressure part circuitry;
- Replacement of the existing coal combustion burners with natural gas burners;
- Installation of new gas piping and valve racks;
- Installation of new gas burning igniters;
- Installation of new main flame scanners;
- Associated electrical, instrumentation and burner management control system modifications;
- Continuous Emissions Monitoring System modifications;

- Installation of new fuel gas check metering, heater and pressure regulating station, and
- Installation of two flame scanner cooling air blowers.

It also was necessary to install a natural gas transport supply pipeline lateral to the plant site.

Q. WHEN WAS BIG SANDY PLACED IN SERVICE AS A GAS-FIRED UNIT?

A. Big Sandy was placed in service as a gas-fired unit on May 31, 2016.

V. STATUS OF BIG SANDY UNIT 2 DECOMMISSIONING

Q. WHAT IS THE STATUS OF BIG SANDY UNIT 2?

A. Kentucky Power retired Big Sandy Unit 2 on June 1, 2015. The Company is currently decommissioning and demolishing the unit.

Q. PLEASE DESCRIBE THE DECOMISSIONING AND DEMOLITION ACTIVITIES AT BIG SANDY PLANT.

A. Following the retirement of Big Sandy Unit 2 and the conversion of Big Sandy Unit 1 to natural gas, the Company's decommissioning and demolition activities at Big Sandy include:

- Closure of the fly ash pond
- Asbestos Removal
- Removal of coal handling equipment
- Demolition of the Big Sandy Unit 2 cooling tower
- Removal of coal impacted soils from the former coal yard

Q. DOES THE DECOMMISSIONING AND DEMOLITION ACTIVITY AT BIG SANDY UNIT 2 REPRESENT A CHANGE IN STRATEGY FROM PREVIOUS TESTIMONY PRESENTED IN THE LAST BASE RATE CASE?

A. Yes. At the time of the last base rate case, the Company anticipated retiring Big Sandy Unit 2 in place until such time as Big Sandy Unit 1 retired. Beginning in 2016, and as part of the Company's response to the economic issues facing the service territory, Kentucky Power accelerated the demolition timeline for Big Sandy Unit 2 to facilitate redevelopment of a portion of the Big Sandy property as an economic development site. A description of the economic development potential of the site is included in the testimony of Company Witness Hall.

VI. KENTUCKY POWER GENERATION O&M

Q. WHAT ARE THE O&M REQUIREMENTS OF KENTUCKY POWER'S GENERATION ASSETS?

A. Each of Kentucky Power's plants must provide safe, economical, and reliable generation output to serve load. Because customer demand fluctuates continuously, each generating plant must be prepared to accommodate these fluctuations. In addition, a unit's maintenance needs vary based on its type, design, age, condition, and operational characteristics. All units must be maintained so as to operate when required, and to do so in a safe manner in compliance with all local, state, and federal regulations.

Q. HOW ARE O&M COSTS CONTROLLED AT THE PLANTS?

A. To minimize O&M expenses, Kentucky Power relies on a system of maintenance and operations management programs to ensure optimal performance of the generating assets. These maintenance programs are:

- Predictive Maintenance: monitoring, inspections, and/or data analyses conducted to diagnose potential maintenance issues early and usually while the equipment is running so as to minimize downtime.
- Preventive Maintenance: protocols, testing, and physical work conducted on equipment to address anticipated or diagnosed vulnerabilities.

In addition, continuous improvements are incorporated into the operations and maintenance of the generating units to eliminate waste and increase process efficiencies. Together, these maintenance and management programs help to optimize operation of the assets and limit O&M cost escalations.

Q. WHAT PERIOD WAS USED TO DEVELOP THE TEST YEAR GENERATION O&M EXPENSE FOR KENTUCKY POWER?

A. The test year is the twelve-month period from March 1, 2016 through February 28, 2017.

Q. WHAT IS KENTUCKY POWER'S ADJUSTED TEST YEAR LEVEL OF GENERATION O&M EXPENSE?

A. Kentucky Power's non-fuel, non-labor adjusted test year Generation O&M expense is $23.9 million. The Generation O&M expense comprises two categories of expenses: steam maintenance and steam operations. As shown in Table 2 below, Kentucky Power's adjusted test year Generation O&M expenses include steam maintenance and steam operations amounts for Big Sandy, the Company's 50% undivided interest in Mitchell, and shared plant costs not attributable to a specific generating unit (known as Non-Plant costs).

Table 2: Kentucky Power Non-Fuel, Non-Labor Adjusted Test Year Generation O&M

Category	Mitchell	Big Sandy	Non-Plant	Total
Steam Maintenance	$12,276,224	$3,963,396	($218,529)	$16,021,091
Steam Operations	$3,630,309	$2,259,825	$1,986,401	$7,876,535
Total	**$15,906,533**	**$6,223,221**	**$1,767,872**	**$23,897,626**

Q. WHY DID THE TEST YEAR STEAM MAINTENANCE NON-PLANT COSTS SHOW A CREDIT?

A. The driver for the negative account balance was the timing of monthly accounting accruals and reversals. At the end of the test year, the net of these transactions over the 12-month period resulted in a negative balance.

Q. WAS IT NECESSARY TO NORMALIZE ANY PART OF THE TEST YEAR O&M EXPENSES?

A. Yes. Steam maintenance work and expenses can vary materially from year to year. The variable nature of maintenance expenditures is primarily driven by planned unit outages and periodic planned repairs and replacements of unit components. For example, each Mitchell unit typically is scheduled for one planned maintenance outage during any three-year period. As a result, two years of each three-year period will contain scheduled outages of a Mitchell unit and the third year will have no scheduled outages. Also, forced outages, which by definition do not occur on a predetermined schedule, will contribute to additional variability in the costs. Due to such variability, normalizing those levels of expenses over a three year time period presents a more representative level of steam maintenance expense and contributes to the determination of fair, just, and reasonable rates.

Q. HOW DID KENTUCKY POWER NORMALIZE THE MITCHELL TEST YEAR STEAM MAINTENANCE EXPENSE?

A. As described in the testimony of Company Witness Wohnhas, and consistent with previous rate adjustment applications, an adjustment has been made to the test year steam maintenance expense at Mitchell by using the average for the three year historical period as adjusted for inflation.

Q. HOW WAS THE BIG SANDY TEST YEAR STEAM MAINTENANCE EXPENSE NORMALIZED?

A. As described in the testimony of Company Witness Wohnhas, an adjustment has been made to the test year steam maintenance expense at Big Sandy by using the annualized gas portion of the O&M expense as the three-year average expense amount. Annualizing the gas-fired portion of the test year steam maintenance expense is necessary to account for the fact that Big Sandy only operated as a gas-fired unit for nine months of the test year.

Q. DOES THE ADJUSTED TOTAL AMOUNT OF $23.9 MILLION REPRESENT AN APPROPRIATE AND REASONABLE GOING LEVEL FOR O&M AT KENTUCKY POWER'S GENERATION ASSETS?

A. Yes. This total level is reasonable, and fairly reflects an appropriate level of O&M for Big Sandy and Kentucky Power's 50% share of the Mitchell Plant.

Q. ARE ANY MODIFICATIONS OR ADDITIONS PLANNED FOR MITCHELL OR BIG SANDY THAT WOULD AFFECT EXPECTED GENERATION O&M EXPENSES?

A. No. The Company is not currently planning any modifications that would impact O&M expenses at either plant.

VII. THE 2017 ENVIRONMENTAL COMPLIANCE PLAN

Q. ARE THERE ANY SIGNIFICANT CAPITAL PROJECTS THAT ARE BEING PROPOSED FOR INCLUSION IN THE COMPANY'S 2017 ENVIRONMENTAL COMPLIANCE PLAN?

A. Yes. As described by Company Witness Elliott, the Company is proposing to include the Rockport Unit 1 SCR project which will control NOx emissions, as part of its 2017 Environmental Compliance Plan. As described by Company Witness McManus, the SCR installation is required for compliance with the Federal Clean Air Act and the related 2007 NSR Consent Decree.

Q. WHAT IS THE STATUS OF CONSTRUCTION OF THE ROCKPORT UNIT 1 SCR?

A**.** The project is currently in the final stage of construction and estimated to be completed during the third quarter 2017. Construction began in July 2015, following the May 2015 issuance of a Certificate of Public Convenience and Necessity ("CPCN") by the Indiana Utility Regulatory Commission ("Indiana Commission") in Cause No. 44523.

Q. HOW DOES AN SCR CONTROL NO_X?

A. Nitrogen oxides, collectively referred to as $NO_{X,}$ are created in the steam generator as a byproduct of the combustion process. The SCR technology injects ammonia as a reagent into the flue gas stream, which is then passed over a catalyst. The ammonia and NO_X react on the catalyst surface to form nitrogen gas and water vapor, reducing the amount of NO_X in the flue gas stream. In combination with the low NO_X burners and overfire air system already utilized at Rockport Unit 1, the addition of an SCR is the most reasonable and cost-effective method to achieve the significant additional NO_X emissions reductions required for compliance.

Q. WILL THE INSTALLATION OF AN SCR AFFECT THE GENERATING CAPACITY OF ROCKPORT UNIT 1?

A. No it will not.

Q. PLEASE DESCRIBE THE ROCKPORT UNIT 1 SCR INSTALLATION.

A. The SCR project requires the installation of new equipment and controls, and upgrades to existing plant equipment. New equipment being installed as part of the SCR system includes:

- Ammonia storage and injection systems;
- SCR reactor modules (3);
- Catalyst installation and removal systems;
- Tie-in ductwork;
- Air heater basket replacement with installation of new multi-media cleaning devices;
- Equipment to supply electrical needs of new process equipment;
- Ammonia slip monitoring equipment;
- Balance of plant equipment for SCR system.

Upgrades to the existing plant equipment include reinforcement of existing steel, access platforms, walkways, and stairs. Heating, ventilation and air conditioning equipment modifications also are being undertaken.

Q. WHAT IS THE ESTIMATED COST FOR THE INSTALLATION OF THE SCR ON UNIT 1 OF THE ROCKPORT PLANT?

A. The current estimated final cost for the SCR installation is $268.5 million, excluding Allowance for Funds Used During Construction. This cost estimate includes the installation of the SCR, associated upgrades to existing plant equipment, and allocated costs for support of the project.

Q. ASIDE FROM THE INITIAL CAPITAL COST OF THE PROJECT, ARE THERE ANY RELATED EXPENSES THAT WILL BE INCURRED OVER THE LIFE OF THE SCR?

A. Yes. There will be intermittent capital costs associated with replacing depleted catalyst layers. In addition, there will be fixed and variable O&M costs associated with the operation of the Rockport Unit 1 SCR. The fixed O&M costs will be associated with maintenance that must be performed to maintain the operability of the SCR system. The variable O&M cost consists of the anhydrous ammonia, which is injected into the flue gas stream as part of the SCR's operation.

Q. WHAT STEPS WERE TAKEN TO ENSURE THAT THE PROJECT IS REASONABLE AND COST-EFFECTIVE?

A. An SCR system is a proven, reliable technology used throughout the electric utility industry to reduce NO_X emissions. It has been successfully installed on fourteen AEP-operated units, four of which are 1300 MW units that are similar to the Rockport units. This provides Kentucky Power customers the significant benefit of the lessons learned from these prior experiences.

AEP Service Company ("AEPSC"), on behalf of I&M, executed the Rockport Unit 1 SCR Project using the same phased approach that has been successfully employed by AEPSC on multiple past projects, including the recent Big Sandy Unit 1 gas conversion. The three-phase approach provided structured control of the project scope and costs by providing a minimum of three specific decision points where engineering, design, cost and schedule are reviewed. Phase I consisted primarily of a feasibility study in which technical options and costs are evaluated and technology selection is made. In Phase IIa and IIb, preliminary and then detailed engineering and design were produced to aid in refining costs, particularly with procurement and contracting. In addition, participation by the construction team in the design phases assured that the equipment layout and modularization allowed for optimized constructability and provided a smooth transition into the major construction phase of the project.

Full-scale construction, startup, and commissioning are part of Phase III. Beginning major construction activities and contracting when detailed design is substantially complete allowed for construction to proceed, in many cases, on a fixed or target price basis. This practice served to mitigate cost risks since many of the design changes that might otherwise result in additional work and cost were identified and remedied.

Throughout the three-phase project planning and execution, AEPSC used prudent project and construction management practices to ensure that the project was accomplished in a safe, professional and cost-effective manner.

Q. DID AEPSC EMPLOY ANY METHODS TO MITIGATE THE RISK OF COST ESCALATION OF ON THE ROCKPORT UNIT 1 SCR PROJECT?

A. Yes. AEPSC's strategies of being first to market, locking in queues in production facilities, entering into procurement arrangements such as Discount Cooperative Agreements with major equipment vendors, and procuring materials and commodities in bulk at fixed prices served to mitigate the risk of market price spikes.

Q. IS IT YOUR OPINION THAT THE SCR INSTALLATION ON ROCKPORT UNIT 1 IS REASONABLE AND COST-EFFECTIVE?

A. Yes. As part of its application to the Indiana Commission for a CPCN for the Rockport Unit 1 SCR, I&M demonstrated that installing the SCR on Unit 1 was the least cost alternative versus retiring the unit (as would be required under the Consent Decree) and replacing it with another generation option or with market purchases. In its final Order, the Indiana Commission held that "I&M considered retrofit and retirement options, and the retirement of Rockport Unit 1 is not a reasonable or cost effective means of providing low cost environmentally reasonable power to its customers."[1] By being both a highly effective and the least cost alternative, the Rockport Unit 1 SCR retrofit is a reasonable and cost effective means for the Rockport Plant to comply with its environmental requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

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[1] Order of the Commission, *Verified Petition Of Indiana Michigan Power Company (I&M), An Indiana Corporation, For Approval Of A Clean Energy Project And Qualified Pollution Control Property And For Issuance Of Certificates Of Public Convenience And Necessity For Use Of Clean Coal Technology And Compliance With Federally Mandated Requirement (Project); For Ongoing Review; For Approval Of Accounting And Ratemaking, Including The Timely Recovery Of Costs Incurred During Construction And Operation Of Such Project Through I&M's Clean Coal Technology Rider; For Approval Of Depreciation Proposal For Such Project; And For Authority To Defer Costs Incurred During Construction And Operation, Including Carrying Costs, Depreciation, Taxes, Operation And Maintenance And Allocated Costs, Until Such Costs Are Reflected In The Clean Coal Technology Rider Or Otherwise Reflected In I&M's Basic Rates And Charges* at 19, Cause No. 44523 (Ind. U.R.C., May 13, 2015).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

DIRECT TESTIMONY OF

EVERETT G. PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned Everett G. Phillips, being duly sworn, deposes and says he is the Managing Director, Distribution Region Operations for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Everett G. Phillips

Everett G Phillips

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Everett G. Phillips, this the 21st day of June 2017.

Trisha M. Young Blum

Notary Public

My Commission Expires: 3-18-19

COMMONWEALTH OF KENTUCKY
TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

DIRECT TESTIMONY
OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
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DIRECT TESTIMONY

OF
EVERETT G. PHILLIPS
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2017-00179

I. INTRODUCTION

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

A. My name is Everett G. Phillips. My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101. I am the Managing Director of Distribution Region Operations for the Kentucky Power Company ("Kentucky Power" or "Company"). Kentucky Power Company is a subsidiary of American Electric Power Company, Inc. ("AEP").

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

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University and a master's degree in Business Administration in 2007 from University of Phoenix. I am a registered professional engineer in the Commonwealth of Kentucky. I am a member of the National Society of Professional Engineers. I am an advisory board member of the Power and Energy Institute of Kentucky for the University of Kentucky and a member of the applied process technologies advisory committee for the Ashland Community and Technical College. Throughout my career, I have held positions of increasing responsibility. In 1998, I was promoted to the Kentucky Power Pikeville district superintendent position, and in 2000, I was promoted to the Pikeville district manager. In 2004, I moved to Ashland, Kentucky where I served as Director of Customer and Distribution Operations. In 2011, I assumed my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF DISTRIBUTION REGION OPERATIONS?

A. I am responsible for overseeing all aspects of the Company's distribution system, including the planning, construction, operation, and maintenance of the system. My duties also include the oversight and management of service extensions to new customers, the safe and reliable delivery of service to our customers, and the restoration of service when outages occur. I am also responsible for Kentucky Power's Distribution Vegetation Management Program and oversee distribution smart grid investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before this Commission and filed testimony in the Company's base rate case filings, Case No. 2009-00459 and 2014-00396. My testimony in each focused on the Company's Distribution Vegetation Management Program and system reliability.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of Kentucky Power's current distribution power quality and service reliability programs. First, as the Commission directed in its November 3, 2016 Order in Case No. 2016-00180, I address Kentucky Power's storm preparedness, its response to outages, its system reliability, and the effectiveness of the Company's Distribution Vegetation Management Program. Second, I discuss the yearly Distribution Operation and Maintenance expenses and capital spending since the last base case (Case No. 2014-00396). Third, I describe the Company's implementation of the Distribution Vegetation Management Plan ("Plan"), and the changes to the Plan being proposed by Kentucky Power. Finally, I discuss the Company's Smart Grid investments, the Smart Grid technology the Company is considering, as well as new opportunities for continued reliability improvement.

Q. **ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?**

A. Yes. I am sponsoring the following exhibits attached to my testimony:

Exhibit	**Description**
EXHIBIT EGP-1	CUSTOMER RELIABILITY EXPECTATIONS
EXHIBIT EGP-2	MAP OF THE KENTUCKY POWER SERVICE AREA
EXHIBIT EGP-3	FOREST LAND DISTRIBUTION FOR STATE OF KENTUCKY
EXHIBIT EGP-4	ANNUAL VEGETATION MANAGEMENT REPORTS
EXHIBIT EGP-5	COMPARISON OF FIVE-YEAR CYCLE AND SIX-YEAR CYCLE PROPOSALS

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

III. <u>RESPONSE TO DEFERRAL ORDER</u>

Q. PLEASE DESCRIBE THE DISTRIBUTION SYSTEM THAT SERVES KENTUCKY POWER'S CUSTOMERS.

A. Kentucky Power serves approximately 168,000 retail customers in Kentucky in a service area that covers approximately 3,780 square miles. Kentucky Power's Distribution System includes approximately 10,080 line miles of underground and above-ground primary and secondary voltage lines.

Q. IN ITS NOVEMBER 3, 2016 ORDER IN CASE NO. 2016-00180 THE COMMISSION INDICATED IT PLANNED TO UNDERTAKE "A DETAILED REVIEW OF KENTUCKY POWER'S STORM PREPAREDNESS, ITS RESPONSE TO OUTAGES, AND SYSTEM RELIABILITY, ALL OF WHICH ARE ISSUES OF GREAT INTEREST TO THE COMMISSION." FIRST, PLEASE DETAIL KENTUCKY POWER'S STORM PREPAREDNESS EFFORTS.

A. Kentucky Power's storm preparedness efforts fall into two broad categories: (a) system hardening and resiliency; and (b) storm responsiveness. System hardening includes Kentucky Power's systematic approach to improve the existing infrastructure to make it more durable for both normal operating conditions and weather-related events. Grid resiliency efforts are designed to minimize the number of customers affected by an outage, as well as to enable the Company to restore power outages more quickly and efficiently when outages occur. There often is an overlap between system hardening and system resiliency activities, and for the most part I will discuss them together below.

The second category, storm responsiveness, includes Kentucky Power's regular and ongoing efforts to prepare to respond quickly when a major storm strikes. I discuss these efforts following my discussion immediately below of the Company's system hardening and system resiliency activities.

1. <u>SYSTEM HARDENING AND SYSTEM RESILIENCY</u>

Q. PLEASE DETAIL THE TYPES OF ACTIVITIES ENCOMPASSED WITHIN THE PHRASE "SYSTEM HARDENING."

A. System hardening includes building, maintaining, and upgrading the distribution system so that it is able to withstand the forces – both during normal operating conditions and during Major Storm Events – that may occur. These forces include thermal expansion and contraction from heat and cold, wind-loading from high winds, and ice buildup on conductors and hardware. Kentucky Power is upgrading many of its distribution facilities from Grade C facilities to Grade B facilities. (Grade B facilities are designed to withstand up to one-half inch of radial ice; Grade C structures are designed to withstand one-quarter inch of radial ice.) These upgrades include installing stronger structures, lessening the span length on existing distribution circuits to reduce tension on existing poles, and increasing the strength of down guys and anchors on dead-end structures.

Another important component of the Company's regular system hardening efforts is the Company's distribution Vegetation Management Program. That program seeks to reduce the storm-related risk of damage to the grid by removing trees from within the rights-of-way and danger trees outside the rights-of-way.

Q. WHAT TYPES OF ACTIVITIES DOES KENTUCKY POWER UNDERTAKE TO MAKE ITS DISTRIBUTION SYSTEM MORE RESILIENT?

A. Kentucky Power's distribution Vegetation Management Program also aids grid resiliency. Other examples of grid resiliency activities include installing devices such as line reclosers, sectionalizers, and line fuses to sectionalize the system so that, in the event of a fault on the system, these devices isolate the faulted location. This limits the duration of the outage experienced by the customers on the remainder of the line. Other examples include Supervisory Control and Data Acquisition systems that allow for equipment to be controlled remotely, as well as distribution automation that include schemes and equipment to allow the distribution grid to automatically recover to the extent practicable when an outage occurs. Over three million dollars was invested in telecommunication upgrades, including Supervisory Control and Data Acquisition technology, in support of the Company's efforts to improve system resiliency since the last base case.

Q. WHEN DOES KENTUCKY POWER PERFORM SYSTEM HARDENING AND SYSTEM RESILIENCY ACTIVITIES?

A. The Company undertakes hardening and resiliency activities in conjunction with both its Vegetation Management Plan work and in connection with Kentucky Power's normal maintenance activities. The system hardening and resiliency activities primarily are focused on those circuits that are most at risk of being affected by weather events. During normal maintenance activities, Kentucky Power performs ground line inspections of poles, upgrades and replaces cross arms and poles as needed to better withstand weather events, installs additional lightning mitigation, and hardens overhead highway crossings on the distribution system. The Company also adds sectionalizing devices to distribution circuits to minimize the number of customers impacted by an outage on a lateral line. In addition, the Company upgrades distribution substation breakers and relays to meet current standards, implements distribution automation where practicable, and increases maintenance activities to improve grid resiliency.

Q. HOW DOES THE COMPANY PRIORITIZE THESE ACTIVITIES?

A. Kentucky Power analyzes individual circuits annually to identify the worst performing circuits. Kentucky Power focuses work on individual circuits based upon each circuit's performance during storms, as well as the day-to-day performance of the circuit under normal operating conditions. Kentucky Power then estimates the number of structures that will need to be upgraded, the number of structures that will need to be installed to shorten span lengths, and the number of additional down guys and anchors that will need to be added or upgraded to better withstand more severe weather conditions. Kentucky Power also performs ground line inspections on existing structures that were not replaced to ensure the durability of the pole. During the 2016 ground-line inspection, 9,511 poles were inspected, 2,341 poles were treated, and 270 poles were identified for replacement.

Kentucky Power also identifies those distribution facilities that would require large volumes of line crew resources during extended outages, and that could affect emergency responders such as police, fire and ambulance operators. As an example, these assessments led to the relocation of sections of the Coalton-Trace

Creek, Daisy-Leatherwood, Dewey-Inez and Draffin-Yellow Hill lines to make these circuits more accessible.

Distribution automation projects are also evaluated based upon available system capacity and resources in a given area. Other factors that are considered include the number of customers in a given area, past reliability performance, as well as the deployment of new technology. Kentucky Power is actively installing Distribution Automation – Circuit Reconfiguration technology, which adds more automatic reclosers to circuits to isolate faults and get more customers restored more quickly during an outage. This will be described in more detail in the Smart Grid section of my testimony.

Q. DO SYSTEM HARDENING AND SYSTEM RESILIENCY ACTIVITIES REQUIRE BOTH OPERATION AND MAINTENANCE EXPENDITURES AND CAPITAL INVESTMENT?

A. Yes. The maintenance and inspection program-related costs are expensed to Operation and Maintenance, while the replacement of major assets is recorded as capital investments. Both are required to maintain a distribution grid that will meet the expectations of Kentucky Power's customers.

Q. PLEASE DESCRIBE THE COMPANY'S 2016 SYTEM HARDENING AND SYSTEM RESILIENCY OPERATION AND MAINTENANCE EXPENDITURES AND CAPITAL INVESTMENTS?

A. Kentucky Power in 2016 spent approximately $2.2 million in Operation and Maintenance dollars to inspect poles, circuits, reclosers, regulators, capacitors, air break switches, underground cable and substations. When weak or damaged assets or materials are identified during inspections, the items were replaced or upgraded to ensure the distribution system is less prone to failure during adverse conditions. Table 1 lists Kentucky Power's consumption of common distribution materials and supplies over the past three years:

Table 1 – Kentucky Power Common Material Issued Annually

ITEM	2014	2015	2016
Cross Arm	2,927	2,597	2,921
Arrestor	3,816	3,503	4,045
Cutout	6,114	5,917	6,693
Insulator	18,113	18,110	19,690
Pole	2,911	3,161	3,242
Splice	31,764	36,077	27,316
Transformer	1,730	1,473	1,437
Wire (Ft)	2,259,345	2,104,227	1,860,570

The listed items include those that typically fail during a storm or adverse conditions. The materials listed in Table 1 were issued for all purposes and not just system hardening and system resiliency. Nevertheless, replacing these items for whatever reason before they fail is an important part of Kentucky Power's system hardening and system resiliency efforts.

2. <u>**STORM RESPONSIVENESS**</u>

Q. PLEASE DESCRIBE HOW KENTUCKY POWER PREPARES TO RESPOND TO MAJOR STORM EVENTS?

A. The second part of Kentucky Power's storm preparedness efforts is its regular and ongoing effort to lay the groundwork to respond quickly when a major storm strikes. Procedures are in place to assess a storm before it hits using intelligent weather monitoring services, and when required, to ramp up personnel, communications, materials, equipment and outside resources to match the severity of the storm. Mutual assistance programs allow Kentucky Power to bring in additional resources from outside the Company and state when needed to restore power more quickly. The Company also conducts training exercises periodically to ensure key employees understand their role and can practice their response.

Q. HOW DOES KENTUCKY POWER RESPOND TO STORM-RELATED DAMAGE AND OUTAGES?

A. Even before a major storm hits, the Company is assessing the pending storm event. If severe weather is predicted, the distribution team convenes via conference calls to evaluate the incoming weather to anticipate the amount of damage that might be sustained. Then, the appropriate personnel are notified with instructions on how to proceed. As outages begin, the Distribution Dispatch Center may receive an alarm indicating a substation circuit breaker has "locked out" because of a permanent fault on a distribution feeder. The Customer Operations Center may also receive outage calls from customers, which in turn leads to personnel entering tickets in the Company's Outage Management System. As Kentucky Power determines the location of the outages, personnel are dispatched to outage locations to assess the cause of the outage and to determine the resources required to repair the damage. The necessary resources are then allocated to remove hazards, to complete the repairs and to restore service. The Company continually monitors the outages and resources to restore service as quickly as possible. Outage restoration times are continually estimated and updated to provide customers the most up-to-date information about their service restoration. For severe or major storms, the

Company may request mutual assistance from other utilities or contractors to supplement the response effort. Details of the Company's response are recorded for reporting purposes and post-event evaluation. The response information and system performance information are used for future process improvement and evaluation of program effectiveness.

Q. HAS KENTUCKY POWER IMPLEMENTED IMPROVEMENTS TO ITS STORM RESPONSIVENESS PROCESS?

A. Yes. The Company implemented an Incident Command System process as part of the Emergency Restoration Plan project during 2015. The Incident Command System is a standardized, on-scene, all-hazard incident management tool that allows responders to manage both small and large emergencies such as outages related to major storms and other events requiring quick responses. Its key element is a common chain of command where the roles are clearly defined. The benefits of the process Incident Command System include that it:

- Establishes consistent roles and responsibilities;
- Separates key restoration roles, i.e., operations, planning, logistics, finance and safety;
- Limits spans of control;
- Clearly defines and limits the focus of employee's responsibilities during the restoration or emergency response;
- Provides standardized terminology that will allow for effective and efficient communication internally and with local, state, and federal government agencies; and

- Allows the Company to share resources efficiently and effectively regardless of the incident size and transition employees throughout the service area during events.

Q. WHAT WAS INVOLVED IN IMPLEMENTING THE INCIDENT COMMAND SYSTEM?

A. Kentucky Power deployed new technology and improved its processes. These improvements were undertaken to improve the Company's efficiency and performance in restoring service after a major or severe storm. The Incident Command System is the same process used by other utilities and agencies such as the military and local and state government emergency responders in responding to emergencies. The technology deployment included enhancements to Outage Management System software used to track distribution outage data, improvements to the Estimated Time of Restoration, which is the approximate time communicated to customers through the Company's website to indicate when electric service will be restored, and improved damaged assessment tools, which help first responders to collect information on damage to the Company's facilities and the resources required to restore service.

Q. IS THE COMPANY BETTER PREPARED FOR FUTURE STORMS?

A. Yes. The Company completed Incident Command System implementation and simulation training in February and March of 2015. Mock exercises were conducted in October 2015 and November 2016. The Incident Command System process improves both internal and external communications and coordination of restoration efforts and produces shorter outages for our customers. Drills are planned annually. The next exercise drill is scheduled for the fall of 2017.

IV. DISTRIBUTION RELIABILITY PROGRAMS

1. RELIABILITY STRATEGY

Q. PLEASE DESCRIBE THE COMPANY STRATEGY FOR IMPROVEMENTS IN SYSTEM RELIABILITY.

A. Kentucky Power's strategy for system reliability improvement is a balanced approach that includes monitoring, inspection, maintenance, and investment in replacing aging infrastructure and the implementation of new technologies. By monitoring and inspecting facilities, the Company identifies the causes that affect reliability, and then works to mitigate the causes through process improvements. The Distribution Vegetation Management Program seeks to limit outages resulting from trees and vines inside the Company's rights-of-way, and those caused by "danger trees" located outside the rights-of-way. The reliability programs described below provide oversight and improvements to key processes and facilities that are fundamental to providing reliable customer service. Finally, replacement of aging infrastructure and the installation of new facilities using the latest technology helps to ensure customers will have a reliable distribution grid that serves their needs and expectations.

Q. WHAT IMPACT ARE THESE IMPROVEMENTS HAVING ON THE SYSTEM RELIABILITY METRICS?

A. Reliability metrics are improving. As shown in Table 2, the Company's reliability metrics are generally trending down:

Table 2 – Kentucky Power Reliability Metrics for All Causes

Year	SAIFI	CAIDI	SAIDI

2014	2.373	212.9	505.3
2015	2.467	189.8	468.1
2016	2.166	205.8	445.7

Note: Excludes Major Storms

As described below, SAIDI is the primary metric used by the Commission to assess the progress of the Company's reliability performance progress.

Q. BEFORE ADDRESSING THESE THREE METRICS, DO THE VALUES REPORTED IN TABLE MATCH THOSE PREVIOUSLY REPORTED? IF NOT, PLEASE EXPLAIN WHY.

A. The 2014 SAIFI and CAIDI values and the 2016 SAIFI, SAIDI, and CAIDI values in Table 2 vary from what previously was filed with the Commission. The remaining values are identical to what the Company previously filed. The variances are slight. For example, the 2016 CAIDI metric previously was reported as 205.14. Table 2 reports the value as 205.8. The difference results from updates to data following its filing. For example, upon re-examination of outage data on a circuit by circuit basis slight adjustments may be made to reflect better the cause of an outage, the duration of an outage, or the circuits affected. Kentucky Power constantly works to compile, refine, and file with the Commission the most accurate reliability data.

Q. PLEASE DEFINE THESE RELIABILITY METRICS AND EXPLAIN HOW THE METRICS REFLECT IMPROVING RELIABILITY?

A. SAIDI, CAIDI, and SAIFI are defined in IEEE 1366-2012, the "IEEE Guide for Electric Power Distribution Reliability Indices." SAIDI (System Average Interruption Duration Index) indicates the total duration of interruption for the average customer for the year indicated, and is defined as the "Summation of Customer Interruption

Duration" divided by the "Total Number of Customers Served." The reduction in SAIDI indicates that the duration of outages is decreasing.

CAIDI (Customer Average Interruption Duration Index) represents the average time required to restore service to customers, and it is defined as the "Summation of Customer Interruption Duration" divided by the "Total Number of Customers Interrupted." The downward trend in CAIDI indicates the Company is restoring power slightly more quickly when an outage occurs. Notwithstanding this trend, it is important to note that as the Company adds sectionalizing to reduce the total number of customers affected by a single outage, the duration of the outage, or CAIDI, for the smaller number customers experiencing the outage may increase because Kentucky Power no longer can use "step restoration" to restore a portion of the customers experiencing the outage.

SAIFI (System Average Interruption Frequency Index) indicates how often the average customer experiences a sustained interruption on an annual basis, and is defined as the "Summation of the Total Number of Customers Interrupted" divided by the "Total Number of Customers Served." More plainly stated, it indicates the average number of times a system customer experiences an outage during a year. Again, the number is less in 2016 than it was in 2014.

By monitoring these metrics over an extended period of time, the Company can determine if its reliability efforts are improving reliability or if the strategy needs to be modified to improve the results.

Q. WHY DOES KENTUCKY POWER USE THE IEEE 1366-2012 STANDARD TO REPORT RELIABILITY METRICS?

A. The Commission completed an in-depth evaluation of the reliability reporting practices in Kentucky in Case No. 2011-00450 and ordered the use of the IEEE 1366-2012 Standard (including the use of SAIDI, SAIFI and CAIDI) to evaluate system reliability performance.

Q. WHAT ARE MAJOR STORM EVENTS AND WHY ARE THEY EXCLUDED IN TABLE 2?

A. The IEEE 1366 Standard defines a major event as "an event that exceeds reasonable design and or operational limits of the electric power system. A major event includes at least one Major Event Day (MED)." A MED is defined as "a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purpose of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather)." The IEEE standard uses an accepted statistical approach to determine when it is appropriate to exclude a major event. By excluding major storm events, which by definition are storm events that exceed reasonable design or operational limits, the Company is able to give the Commission a clearer picture of the progress being made to improve reliability.

2. <u>CUSTOMER RELIABILITY EXPECTATIONS</u>

Q. WHAT ARE KENTUCKY POWER'S RESIDENTIAL CUSTOMERS' RELIABILITY EXPECTATIONS?

A. The results from the 2016 Kentucky Power Company customer survey performed by The MSR Group show 32.6 percent, or nearly one-third of residential customer respondents, believe their service reliability expectations will increase over the next five years. In the same survey, 59 percent of residential customers indicated they expected their service reliability to stay at approximately the same level over the next five years.

Similarly, the results show that 29.3 percent of commercial customer respondents believe their service reliability expectations will increase over the next five years, and 61.8 percent of commercial customers anticipated their service reliability will stay at about the same level over the next five years. See Exhibit EGP-1 – Customer Reliability Expectations for a summary of the results.

The increased expectations are driven by the growing dependence by all customer groups on electronic technology. Customers today are becoming more sensitive to interruptions. As a result, any interruption is now more likely to be perceived by customers as degradation in service reliability.

Q. HOW DOES KENTUCKY POWER USE THIS DATA TO PLAN FOR FUTURE DISTRIBUTION SYSTEM RELIABILITY IMPROVEMENTS?

A. Kentucky Power Company values the input of its customers and strives to meet their expectations. The Company recognizes customer expectations can change over time, and Kentucky Power needs to stay customer-focused to ensure the distribution system evolves to meet customer expectations. The Company uses customer survey data in all facets of process improvement, including maintenance programs and future reliability investment.

Customer satisfaction, reliability performance, and investment are like the three-legged stool, and need to be balanced. That is, while striving to meet customer expectations by making investments, the Company focuses its efforts on the most cost-effective measures.

3. KENTUCKY POWER'S RELIABILITY PROGRAMS

Q. HOW DOES KENTUCKY POWER MAINTAIN RELIABILITY ON ITS DISTRIBUTION SYSTEM?

A. Kentucky Power uses a combination of programs to maintain its distribution infrastructure. These programs are designed to reduce the number of service interruptions and to minimize their impact on customers. The Company's distribution management programs can be divided into three major categories:

1) Distribution Asset Management;

2) Major Distribution Reliability and Capacity Additions; and

3) Kentucky Power's Distribution Vegetation Management Program.

Distribution Asset Management and Major Distribution Reliability and Capacity Additions are described immediately below. The Distribution Vegetation Management Program also is briefly described, but a more comprehensive presentation is provided later in my testimony.

Q. PLEASE DESCRIBE KENTUCKY POWER'S DISTRIBUTION ASSET MANAGEMENT PROGRAMS.

A. The Distribution Asset Management Programs are designed to maximize the efficiency of expenditures and optimize system performance. Kentucky Power has ten Distribution Asset Management Programs. The programs and their distribution system roles are:

1. *Overhead Circuit Facilities* -- Inspection and Maintenance Program: Every two years Kentucky Power visually inspects its overhead facilities to identify and correct potential problems before they can lead to an outage or cause a hazardous situation for the public. Through identifying and repairing such potential problems, Kentucky Power's customers experience safer service with fewer service interruptions.
2. *Animal Mitigation Program*: The objective of this Asset Management Program is to reduce the number of animal-caused outages by installing animal guards on line transformers and other line equipment including distribution lines connected to substations at locations that have had, or potentially may have, a high risk of animal-caused outages.
3. *Capacitor Inspection and Maintenance Program*: The purpose of this program is to inspect and maintain all fixed and switched capacitor installations to ensure these devices function properly. Capacitor installations provide voltage support throughout the Kentucky Power service territory and are a critical component in the implementation of Volt/VAR Optimization, which improves the energy efficiency of the Company's distribution system.
4. *Underground Facilities Inspection and Maintenance Program:* Every two years Kentucky Power visually inspects the external, above-ground portions of underground distribution facilities to identify and correct problems before they can cause an outage. Through these inspections,

Kentucky Power identifies and repairs items such as transformers, pedestals, and switchgear.

5. <u>*Pole Inspection and Maintenance Program*</u>: This program maintains and prolongs the mechanical integrity of Kentucky Power's wood poles. As necessary, poles are treated, treated and reinforced, or replaced. This program helps Kentucky Power identify and replace poles that might otherwise fail and cause power interruptions. During 2016, the Company replaced 340 poles, including most of the 270 poles identified for replacement during the inspections, and treated 2,341 poles.

6. <u>*Recloser Maintenance / Replacement Program*</u>: The Company performs preventive maintenance on reclosers, and replaces, as needed, recloser units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service, or result in an interruption to more customers than necessary. In 2016, 176 reclosers were replaced as part of this program.

7. <u>*Overhead Conductor Program*</u>: This program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. Targeted areas are identified using historical reliability data, and also include areas with an abnormal number of splices identified through the overhead facilities inspection program.

8. *Underground Cable Program*: This program corrects underground primary cable deficiencies by restoring the integrity of cable through either cable injection or cable replacement. As is the case with Kentucky Power's Overhead Conductor Program, this program targets areas experiencing circuit interruptions and lessens the likelihood of future interruptions to our customers.

9. *Lightning Mitigation Program*: This program reduces the number of lightning-caused outages through the installation of new lightning arresters at locations known to be prone to lightning-caused outages.

10. *Sectionalizing Program*: This Asset Management Program improves the reliability of Kentucky Power's distribution circuits by adding new, or modifying existing, sectionalizing devices. These sectionalizing devices may be manual pole top switches, automatic devices such as reclosers, automatic switches, or fused cutouts. The addition of manual switches where warranted allows the outage duration to be lessened for the customers served by the unaffected portions of the circuit that can be re-energized. Fused cutouts or reclosers work to remove a faulted section of the circuit from service and prevent the entire circuit from experiencing a sustained outage. This enhanced sectionalizing capability results in smaller circuit segments and fewer customers being interrupted after faults occur on distribution circuits.

Q. PLEASE DESCRIBE KENTUCKY POWER'S MAJOR DISTRIBUTION RELIABILITY AND CAPACITY ADDITION PROGRAM.

A. Kentucky Power identifies areas where the increasing or shifting demand for electricity is approaching the limit of the distribution system's existing load capacity. These specific projects re-conductor portions of the existing distribution circuits or re-configure portions of a circuit. The expansion of the distribution system to serve new customers may also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to Kentucky Power's customers. The Reliability category in Table 3 below details these costs.

Q. BRIEFLY PROVIDE AN OVERVIEW OF KENTUCKY POWER'S 2015 DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

A. Kentucky Power's vegetation management practices are conducted in accordance with standards established by the American National Standards Institute ("ANSI"), the Occupational Safety and Health Administration ("OSHA"), and the National Electrical Safety Code ("NESC"). These standards govern pruning and removing trees; safety and worker protection; work clearance and training requirements; and safety clearance guidelines.

The Company is currently implementing a Commission-approved strategy to transition Kentucky Power's Distribution Vegetation Management Program from a performance-based program to a five-year cycle-based approach. The Kentucky Power service territory is located in an area with rugged terrain and dense forests (Compare Exhibit EGP-2 to Exhibit EGP-3). Of all of the areas within the Commonwealth, Kentucky Power has the most difficult and challenging terrain, which requires more frequent maintenance to ensure consistent reliability throughout the Company's service territory. Once fully implemented, the cycle-based Plan is expected to improve tree-related distribution circuit reliability further through more frequent re-clearing of rights-of-way. Later, I provide more detail concerning the Company's 2015 distribution Vegetation Management Program.

4. CAPITAL INVESTMENT

Q. PLEASE SUMMARIZE THE YEARLY DISTRIBUTION CAPITAL COSTS SINCE SEPTEMBER 30, 2014 (THE TEST YEAR USED IN THE COMPANY'S LAST BASE RATE CASE.)

A. The total capital Plant-In-Service installed since September 30, 2014 was $92,482,663. Details are provided in Table 3 below.

Table 3 - Kentucky Power 2014-2016 Plant-In-Service Capital Costs

Category	2014 (Oct.-Dec.)	2015	2016	2017 (Jan.-Feb.)	Total*
Asset Improvement	$4,282,812	$11,521,177	$11,831,279	$2,389,807	$30,025,075
Customer Service	$3,955,730	$12,292,677	$11,943,357	$1,468,891	$29,660,655
Forestry	$1,301,729	$5,699,748	$3,718,526	$719,584	$11,439,587
Other	$0	$0	$69,758	$0	$69,758
Reliability	$1,636,131	$5,194,087	$5,103,175	$1,486,568	$13,419,961
System Restoration	$501,694	$3,580,284	$3,442,652	$342,997	$7,867,627
Total	**$11,678,096**	**$38,287,973**	**$36,108,747**	**$6,407,847**	**$92,482,663**

*Total additions since 9/30/2014 (end of test year in Case 2014-00396) through 2/28/2017

Q. PLEASE EXPLAIN EACH OF THE CAPITAL PROJECT CATEGORIES.

A. Kentucky Power each year completes a significant number of capital projects of varying degrees of complexity and dollar value. The majority of capital projects completed by Kentucky Power can be classified under one of six general categories. The general capital project categories are:

1. *Asset Improvement*: Asset Improvement projects include replacement of obsolete equipment and other aging infrastructure, as well as the addition

of new assets that support projects associated with smart grid such as the Distribution Automation – Circuit Reconfiguration technology. This technology automatically reconfigures distribution circuits during fault conditions to minimize the impact of outages to the fewest number of customers. Kentucky Power applies this technology to both line and station equipment. This project category also has a significant impact on reducing the duration of customer outages and improving customer reliability.

2. *Customer Service*: These projects support new customer facilities, and include upgrading existing customer facilities, meter installations, and other customer requirements.

3. *Forestry*: Forestry capital projects generally involve widening of rights-of-way, the removal of trees greater than 18 inches in diameter within or outside the rights-of-way, as well as the removal of "cycle buster trees." "Cycle Buster Trees" are trees greater than 18" in diameter that must be trimmed or removed before the circuit is due for its next cycle.

4. *Reliability*: Reliability capital projects are specific projects that target known reliability issues affecting both groups of customers and entire circuits. These projects may also be used to add capacity to the system, and include new circuits or stations, additions to existing facilities, and replacing existing assets with higher capacity assets such as re-conductoring an existing line with an increased conductor size. A recent example of a reliability project is the new Haddix-Troublesome Creek

Circuit. Prior to the Haddix-Troublesome Creek Circuit being placed in service on January 18, 2017, the customers now served by it were served by the Haddix-Quicksand Circuit. The former Haddix-Quicksand Circuit was 213 line miles in length and served 2,017 customers. The new Haddix-Troublesome Creek project reduced the length of the Haddix-Quicksand Circuit by 45% to 116 line miles and reduced the number of customers receiving service on the Haddix-Quicksand Circuit by almost 50% to 1,045 customers. The new Haddix-Troublesome Creek Circuit is 97 line miles and serves 972 customers. Reducing the circuit length and the number of customers served by a single circuit limits the impact from an outage and assists in restoring service more quickly.

Another example of a specific reliability project is the Cutout Replacement Project. Cutouts are identified for replacement because they may crack and fail during repeated freezing and thawing over time.

5. *System Restoration*: These projects replace assets that have failed. Capital projects completed during service restoration are typical system restoration projects, and include replacing poles, re-conductoring full length spans, and replacing transformers damaged during a storm or weather-related event.

6. *Other*: These include miscellaneous projects, as well as distribution projects that support other business units. These include distribution upgrades made in response to a transmission system change.

5. <u>OPERATION AND MAINTENANCE EXPENSE</u>

Q. WHAT WAS THE KENTUCKY POWER DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE FOR THE TEST YEAR?

A. Kentucky Power's unadjusted, actual Distribution Operation and Maintenance Expense for the Test Year ending February 28, 2017 was $49,901,372.

Q. HOW DOES THE TEST YEAR DISTRIBUTION OPERATION AND MAINTENANCE EXPENSES COMPARE WITH HISTORICAL LEVELS FOR KENTUCKY POWER?

A. Table 4 provides the Distribution Operation and Maintenance expenses for 2014 through 2016 and the test year.

Table 4 - Kentucky Power Distribution
Operation and Maintenance Expenses by Year

General Category	2014	2015	2016	Test Year
Asset Improvement	$4,878,026	$4,583,901	$4,716,346	$4,683,735
Customer Service	$780,646	$400,151	$701,125	$861,379
Forestry	$17,567,439	$23,067,891	$27,774,545	$28,259,445
Other	$4,925,328	$5,745,071	$5,375,592	$5,061,171
Amortization of Major Storm Deferral	$4,698,444	$3,563,822	$2,429,200	$2,429,200
Reliability	$551,598	$475,412	$402,309	$422,326
System Restoration	$11,643,120	$9,530,008	$8,073,649	$8,184,116
Grand Total	**$45,044,601**	**$47,366,256**	**$49,472,766**	**$49,901,372**

Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF THE DISTRIBUTION O&M EXPENSES INCLUDED IN THE TEST YEAR.

A. The largest Operation and Maintenance expense of the Test Year is the Forestry expense in connection with the implementation of the Company's Distribution Vegetation Management Plan approved by the Commission in Case No. 2014-00396. This level of Forestry expense is expected to continue until Task 1 and Task 2 work (described below) is completed.

The System Restoration expense can vary from year-to-year, and is largely dependent on weather events during a particular year. The Customer Service Operation and Maintenance expenditures support customer programs and address customer issues. The Asset Improvement expense represents the Operation and Maintenance expense associated with capital additions such as the replacement of poles, towers, fixtures, conductors, line transformers and station equipment. The other major category is the Amortization of Major Storm Deferral. This reflects the amortization of regulatory assets related to Major Event Storms that were approved by the Commission for later review and potential recovery through rates. Company

Witness Wohnhas addresses this topic in more detail in his testimony. Finally, "other" contains miscellaneous projects and overheads.

V. VEGETATION MANAGEMENT

1. EVOLUTION OF THE COMPANY'S DISTRIBUTION VEGETATION MANAGEMENT PLAN

Q. PLEASE DESCRIBE THE ORIGIN OF THE KENTUCKY POWER'S VEGETATION MANAGEMENT PLAN.

A. Prior to July 2010, Kentucky Power employed a performance-based approach in its distribution vegetation management efforts. With a performance-based approach, vegetation management work was targeted based on a number of factors, including the time elapsed since the last vegetation management activity, individual circuit inspection results, and environmental factors. Initially, resources were targeted to the areas with the greatest and most immediate vegetation management needs.

In the Company's 2009 rate case, Case No. 2009-00459, Kentucky Power proposed increased vegetation management funding to permit the Company to transition over a five-year period to a four-year cycle-based vegetation management plan. The Company's proposed clearing 25% of its distribution system annually following the conclusion of a five-year transition period. Kentucky Power projected incremental Operation and Maintenance expenditures of $13.93 million in year one of the transition period and $16.58 million of Operation and Maintenance expenditures in year five of the transition period. Kentucky Power also projected increasing the annual amount of its test year vegetation management capital expenditures by 132% by year five of the transition period.

Q. DID KENTUCKY POWER IMPLEMENT ITS 2009 DISTRIBUTION VEGETATION MANAGEMENT PROPOSAL?

A. No. The parties to the case agreed to, and the Commission approved, a revised distribution vegetation management plan ("2010 Vegetation Management Plan"). Under the 2010 Vegetation Management Plan, the Company's test year vegetation management O&M expenditures were increased by $10 million to $17,237,965 in lieu of the $13.93 million to $16.58 million originally proposed. Kentucky Power projected that the transition to a four-year cycle with the additional funding (an additional $10,000,000 annually) provided for under the 2010 Vegetation Management Plan approved by the Commission would require seven years. The Company also agreed to increased reporting by Kentucky Power on its distribution management efforts. The 2010 Vegetation Management Plan and the corresponding funding were to remain in effect until the Company's next base rate case.

Q. WHY DID KENTUCKY POWER SEEK TO AMEND ITS 2010 VEGETATION MANAGEMENT PLAN IN CASE NO. 2014-00396?

A. At the time the Company filed its 2014 rate case application in December 2014, it had four and one-half years of experience with the 2010 Vegetation Management Plan. Based on that experience, the Company determined that the extent of work required to transition to a four-year cycle was significantly greater than the Company estimated in 2010. For example, Kentucky Power initially projected that approximately 763,000 trees would have to be removed in transitioning to a four-year cycle over the projected seven years. Yet, during the first four and one-half years of the program the Company was required to remove over 900,000 trees. Above normal precipitation during the first four years of the plan also led to increased work and expense. Finally, Kentucky Power determined it had underestimated the time and expense required to remove vegetation from within and in close proximity to its energized facilities. Based on this experience, Kentucky Power estimated that an additional eighteen months (or until December 31, 2018) would be required to complete the initial re-clearing (Task 1) of its distribution system. The Company also determined that it could not wait until the Task 1 work was completed to begin re-clearing the circuits that were re-cleared at the beginning of the program. Kentucky Power proposed that beginning in July 2015, when the requested additional funding would be available if the Company's request were granted, Kentucky Power would undertake interim re-clearing cycle (Task 2) work that would proceed simultaneously with the remaining Task 1 work.

Q. WHAT CHANGES TO THE 2010 PLAN DID KENTUCKY POWER ORIGINALLY PROPOSE IN ITS APPLICATION IN CASE NO. 2014-00396?

A. Kentucky Power proposed continuing Task 1 work at a rate of approximately 986 miles per year and at an estimated 2015 cost of $17,605 per mile ($17,358,530 per year.) The estimated Task 1 cost per mile was based on 2014 January through September 2014 actual Task 1 costs. The Company also proposed completing 3,112 miles of Task 2 work by the end of 2018. Kentucky Power estimated the average 2015 per mile cost of Task 2 work at $10,563 per mile, or 60% of the per mile cost for Task 1 work. The 60% cost relationship between Task 1 work and Task 2 was based upon industry experience for re-clearing on a four-year cycle. Under this schedule, the Task 2 work would be completed at the same time as the Task 1 work was scheduled to be completed. Kentucky Power proposed beginning in 2019 the four-year maintenance cycle (Task 3) at an estimated cost of $10,004 per mile. This value, which is approximately 57% of cost of Task 1 work, was based on the Company's original estimate that Task 2 work could be accomplished at 60% of the cost of Task 1 work, and then was further reduced to reflect anticipated efficiencies following ramp-up of operations.

Q. DID KENTUCKY POWER SUBSEQUENTLY AGREE TO AMEND ITS PROPOSAL TO MODIFY THE COMPANY'S 2010 VEGETATION MANAGEMENT PLAN?

A. Yes. Following discovery and settlement negotiations, Kentucky Power and two of the parties to the case agreed to an amended vegetation management plan. The most significant amendment was based on the Company's response to KPSC 3-7. That data request asked Kentucky Power to project the work schedule and the O&M expense associated with the adoption of a five-year cycle (in lieu of the originally proposed four-year cycle) beginning in 2019 for maintenance (Task 3) work. That is, the Task 3 work would comprise a five-year maintenance cycle instead of the four-year maintenance proposed by the Company in its application.

Q. WHAT WAS THE MODIFIED VEGETATION MANAGEMENT PLAN ("2015 VEGETATION MANAGEMENT PLAN") AGREED TO BY KENTUCKY POWER AND THE TWO SETTLING PARTIES?

A. The 2015 Vegetation Management Plan provided for the completion of Task 1 work by December 31, 2018. The Task 2 work was scheduled to be completed by June 30, 2019. Task 3 work was projected to begin July 1, 2019, at which time Kentucky Power's entire distribution system would be re-cleared on a five-year cycle.

Q. DID KENTUCKY POWER AND THE SETTLING PARTIES AGREE ON FUNDING FOR THE 2015 VEGETATION MANAGEMENT PLAN?

A. Yes. Kentucky Power's 2010 Vegetation Management Plan was funded through base rates at an annual amount of $17,237,965. The 2015 Plan was to be funded through an increase in the Company's annual revenue requirement to $27,661,060 until the Company began the five-year maintenance cycle on or about July 1, 2019. The increased funding, and subsequent reduction when Task 3 work was begun discussed below, were premised upon the Company's at-the-time untested estimate that the cost of performing Task 2 work on a five-year cycle would not materially vary from the 60% of the Task 1 cost typical of a four-year cycle. Effective cycle one of the July 2019 billing cycle, which was the estimated date Kentucky Power anticipated completing Task 1 and Task 2 work, the Company's rates were to be reduced by $11,780,408 to reflect the projected reduced costs associated with performing only Task 3 work. The agreement also contained certain other rate-related provisions that I discuss later.

Q. DID THE COMMISSION APPROVE THE 2015 VEGETATION MANAGEMENT PLAN?

A. Yes. It also required Kentucky Power to obtain Commission approval prior to modifying its annual projected vegetation management spending (filed October 1 of the year preceding the implementation of the work plan) on both an aggregate and a district basis by more than 10%. In practice, as I discuss below, this requirement has limited the Company's ability to manage its vegetation management expenditures in the most cost-effective manner.

2. <u>2015 DISTRIBUTION VEGETATION MANAGEMENT PLAN RESULTS</u>

Q. KENTUCKY POWER'S 2015 VEGETATION MANAGEMENT PLAN AS APPROVED BY THE COMMISSION PROJECTS THAT THE COMPANY WILL COMPLETE ITS INITIAL RE-CLEARING OF ITS DISTRIBUTION SYSTEM (TASK 1 WORK) BY DECEMBER 31, 2018. IS KENTUCKY POWER ON PACE TO MEET THAT TARGET?

A. Yes. Exhibit 10 to the Settlement Agreement, which forms the basis for the plan, projected the Company would complete 987 miles of Task 1 work in 2015 and 986 miles of Task 1 work in 2016, for a total of 1,973 miles. During that two-year period, Kentucky Power completed 2,530 miles of Task 1 work or 128% of the target. As a result, Kentucky Power projects it will complete its Task 1 work during the first quarter of 2018. A more complete accounting of the last two calendar years of the Company's Task 1 vegetation management work is provided in Table 5 below.

Table 5 - Summary of Vegetation Management Plan Work Completed

Description	2015		2016		Total	
	Task 1	Task 2 (6 Months)	Task 1	Task 2	Task 1	Task 2
Miles Completed	1,436	434	1,094	711	**2,530**	**1,145**
Brush Cut Acres	1,950	1,130	2,059	1,534	**4,009**	**2,664**
Brush Spray Acres	2,493	279	3,062	778	**5,555**	**1,057**
Trees Removed	212,340	31,834	212,118	87,427	**424,458**	**119,261**
Trees Trimmed	62,825	14,265	52,046	45,622	**114,871**	**59,887**

Further information regarding the 2015 Vegetation Management Plan is provided in Exhibit EGP-4.

Q. WILL THE COMPANY BE ABLE TO COMPLETE THE TASK 2 WORK NO LATER THAN JUNE 30, 2019 AS PROJECTED?

A. Yes. Table 10 of the Settlement Agreement projected that by December 31, 2016 Kentucky Power would complete 1,142 miles of Task 2 work. During that period, Kentucky Power completed 1,145 miles of Task 2 work, or an amount slightly above target. In fact, and as I discuss below, Kentucky Power is proposing to complete its Task 2 work by December 31, 2018.

Q. CAN YOU PUT THE COMPANY'S 2015 VEGETATION MANAGEMENT PLAN EFFORTS IN PERSPECTIVE?

A. In 2015 and 2016, Kentucky Power completed 2,530 miles of Task 1 work. That is equal to the distance between Ashland, Kentucky and San Francisco, California, with almost 350 miles left over for a trip to Los Angeles, California. The 3,675 miles of total 2015 and 2016 combined Task 1 and Task 2 work would stretch from Ashland, Kentucky to Barrow, Alaska, the northernmost city in the United States, which is located 320 miles above the Arctic Circle on the Arctic Ocean. Much of this work was performed in difficult terrain in some of the heavily-wooded topography in the Commonwealth. See Exhibit EGP-3. Another measure of the Company's efforts is that in 2015 and 2016, Kentucky Power removed more than one-half of a million trees as part of its vegetation management efforts. The 424,000 trees removed as part of the Company's Task 1 work alone during this two-year period equals more than 55% of the total trees the Company projected in 2010 it would be required to remove over the entire seven-year transition period to a cycle-based program. Finally, during the last two years, the Company cut over 10.4 square miles of brush; that is equal to an area the approximate size of the city of Ashland. In the same period, its combined 20.75 square miles of brush cut or sprayed is equal to approximately 10% of the area of Boyd County.

Q. EMBEDDED IN KENTUCKY POWER'S BASE RATES BEGINNING JUNE 30, 2015 IS $27,661,060 IN ANNUAL VEGETATION MANAGEMENT O&M SPENDING. DID THE COMPANY MEET THAT TARGET IN 2015 (WHICH INCLUDED SIX MONTHS OF THE INCREASED SPENDING) AND 2016?

A. Yes. As illustrated in Exhibit 9 to the Settlement Agreement, Kentucky Power's combined Task 1 and Task 2 2015 Operation and Maintenance expenditures for the twelve months ended December 31, 2015 were projected to be $22,327,777. During that year the Company's combined Task 1 and Task 2 Operation and Maintenance expenditures were $23,067,891 or 103% of the target. For 2016, Kentucky Power's projected combined Task 1 and Task 2 Operation and Maintenance spending was $27,664,598. The Company's actual Task 1 and Task 2 Operation and Maintenance spending totaled $27,774,545, or slightly more than the target. Since the establishment of the 2010 Distribution Vegetation Management Plan, Kentucky Power's actual distribution vegetation management Operation and Maintenance expenditures through December 31, 2016 totaled $129,117,176, or 101% of its target of $127,563,218.

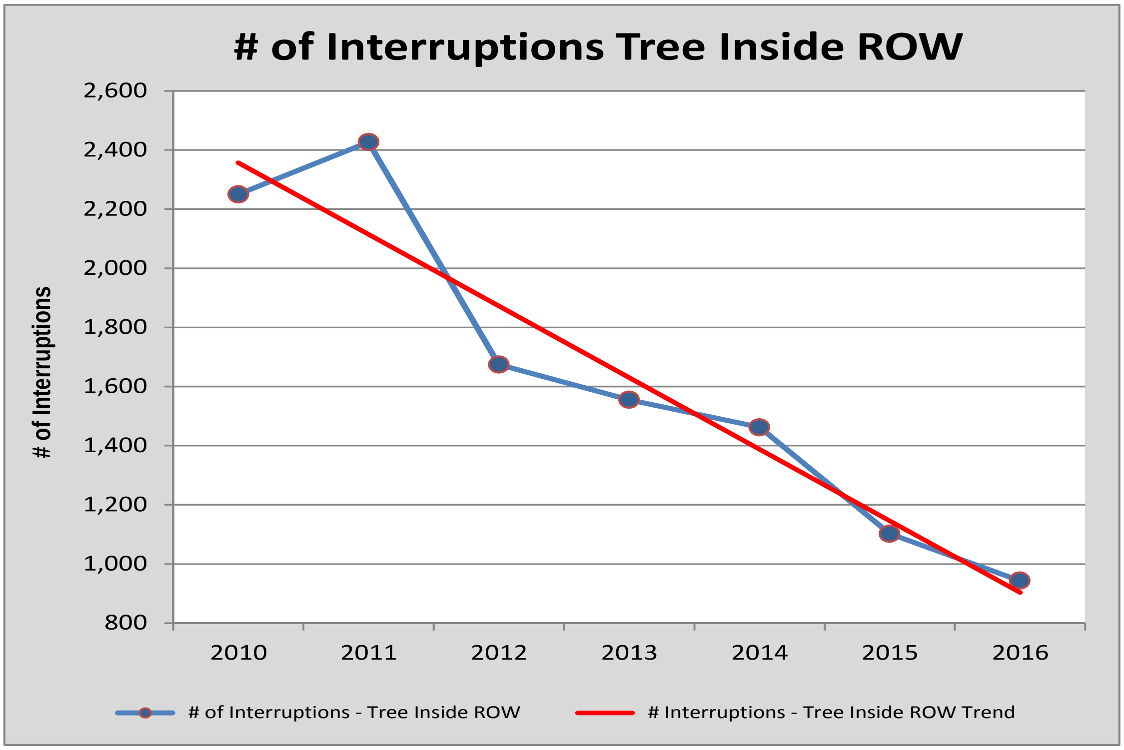
Q. HAVE THE 2010 AND 2015 DISTRIBUTION VEGETATION MANAGEMENT PLANS IMPROVED DISTRIBUTION RELIABILITY FOR THE COMPANY'S CUSTOMERS?

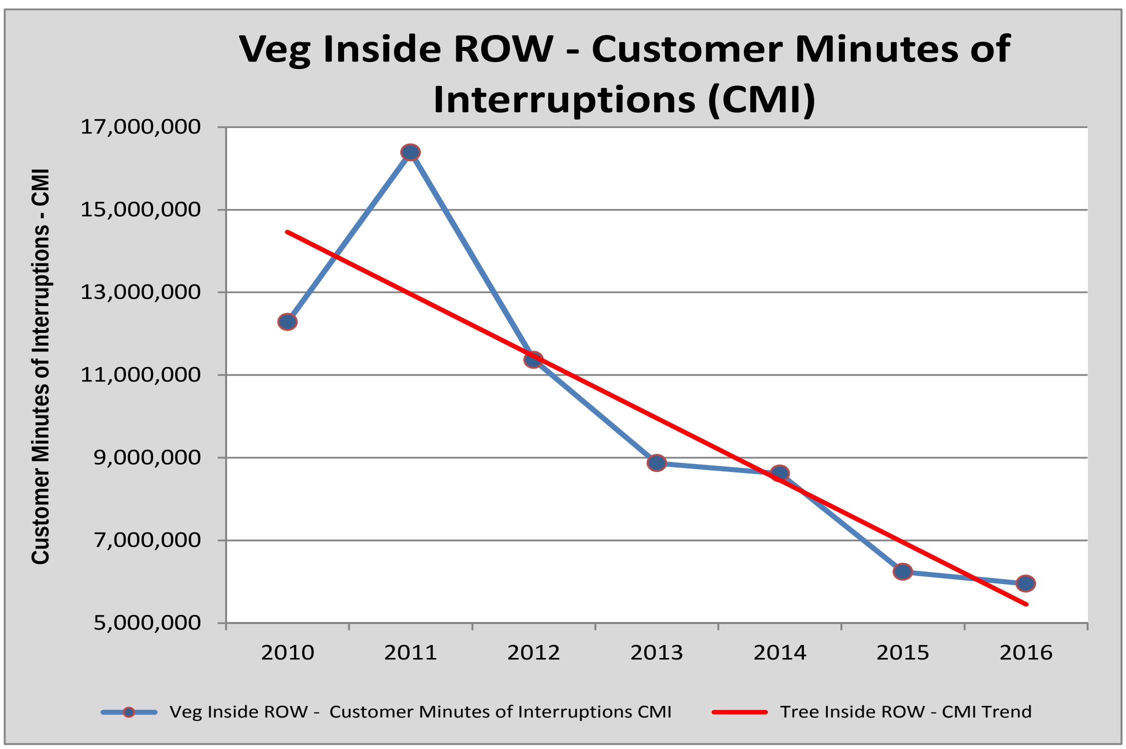
A. Absolutely. Kentucky Power's distribution vegetation management Operation and Maintenance expenditures focus on re-clearing and maintaining the Company's rights-of-way. As a result, the best measure of the effect of Kentucky Power's vegetation management efforts is the number of customer interruptions, total customers affected, as well as customer minutes interrupted, by trees and vines within the Company's rights-of-way. As shown on Table 6 below, the number of incidents of customer interruptions as a result of vines and trees in the Company's rights-of-way declined 61% from a high of 2,426 in the year ended December 2011 to a low of 943 in the year ended December 2016.

Table 6 – Summary Of Inside Rights-Of-Way-Related Outages

Minor Cause Code	Year - 12 Month Ending Dec	Number of Interruptions	Total Customer Affected	Total Customer Minutes Interrupted
TIR + VIN	2010	2,250	64,360	12,280,664
TIR + VIN	2011	2,427	72,076	16,388,594
TIR + VIN	2012	1,674	43,934	11,369,680
TIR + VIN	2013	1,555	48,099	8,866,856
TIR + VIN	2014	1,462	36,471	8,617,318
TIR + VIN	2015	1,102	30,040	6,236,943
TIR + VIN	2016	943	28,713	5,949,862

Consistent with this trend, the number of customers affected by trees and vines within the rights-of-way declined 60% from 72,076 in 2011 to 28,713 last year. Finally, customer minutes interrupted as a result of trees and vines in the rights-of-way, which measure the total impact of the interruptions, declined from 16,388,594 minutes in 2011 to 5,949,862 minutes in the year ended December 31, 2016. That represents a 64% decrease between 2011 and 2016. These improvements are shown graphically in the two charts below:





One point I wish to emphasize is that comparisons between only two years, particularly two consecutive years, which can be affected by temporary conditions such as abnormal weather, can be misleading. The trend over a six-year period, such as shown in Table 6 and the two charts above, however, is strongly indicative of the success the Company and its customers are enjoying from the investment in distribution vegetation management.

Q. DO THE CUSTOMERS INTERRUPTED AND TOTAL CUSTOMER MINUTES INTERRUPTED VALUES IN TABLE 6 REFLECT OUTAGES CAUSED BY MAJOR STORM EVENTS?

A. No. But I am comfortable the severity of outages related to major event storms has been lessened by the success of the Kentucky Power's Distribution Vegetation Plan. For example, a major storm occurred on March 1, 2017 that brought wind speeds of more than 60 miles per hour to the Company's service territory. While there were several outages due to trees and other items from outside the rights-of-way, there were 20 percent less outages due to trees inside the rights-of-way as compared to a similar storm with similar wind speeds on May 8, 2009. The May 2009 storm occurred prior to the initiation of the 2010 Vegetation Management Plan.

Q. ARE TREES AND VEGETATION INSIDE THE RIGHTS-OF-WAY THE ONLY VEGETATION-RELATED CAUSES OF DISTRIBUTION OUTAGES?

A. No. Trees outside the rights-of-way can fall or slide into the rights-of-way. This is particularly true of the substantial portions of the Company's service territory where the Company's distribution facilities are located in areas flanked by steep hillsides. Rights-of-way expansions, and the removal of trees outside the Company's rights-of-way, are accounted for as capital expenditures and thus are in addition to the

Company's vegetation management Operation and Maintenance expenditures I discuss above.

Q. HAS KENTUCKY POWER BEEN MAKING CAPITAL EXPENDITURES IN SUPPORT OF ITS DISTRIBUTION VEGETATION MANAGEMENT PROGRAM?

A. Yes. Before I provide the specifics I should note that in addition to expansion of rights-of-way and the removal of trees outside the Company's rights-of-way, the removal of trees within the rights-of-way larger than 18 inches in diameter also is accounted for as a capital expenditure. With this caveat, Kentucky Power's forestry capital (capital expenditures related to vegetation management) for the past seven years averaged $3.16 million per year and totaled $22.1 million over the same period as shown in Table 7 below.

Table 7 – Kentucky Power Forestry Capital Expenditures (Millions)

Expenditure Year							
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
$1.3	$1.5	$2.6	$3.4	$3.9	$5.7	$3.7	$22.1

Q. PLEASE SUMMARIZE THE COMPANY'S VEGETATION MANAGEMENT EFFORTS TO DATE.

A. The Company is on target to exceed the goals of its 2015 Vegetation Management Plan. It anticipates completing its Task 1 re-clearing work within the first quarter of 2018 and thus nine months early. Kentucky Power also projects that it will complete its interim re-clearing (Task 2) work six months early on December 31, 2018. Most importantly, as demonstrated by the reliability metric most closely related to the work undertaken as part of Kentucky Power's distribution vegetation management plan, the

Company's customers have seen a 60% decrease in interruptions related to inside the rights-of-way trees and vegetation.

Q. THE 2015 DISTRIBUTION VEGETATION MANAGEMENT PLAN PROJECTS THAT ONCE TASK 1 AND TASK 2 WORK IS COMPLETE, TASK 3 (MAINTENANCE RE-CLEARING) WORK CAN BE ACCOMPLISHED AT AN AVERAGE ANNUAL O&M EXPENDITURE OF $15,880,652. IS THAT PROJECTION STILL VALID?

A. No. When Kentucky Power estimated the cost of Task 3 work it assumed that Task 2 work, which served as the starting point of the Company's calculation of the cost of Task 3 work, could be completed at approximately 60% of the cost of Task 1 work. The Company's estimate also was premised upon the expectation that the cost of Task 3 work on a five-year cycle would not materially differ from performing Task 3 work on a four-year cycle. The Company used the 60% value for Task 2 work, which is based on the cost of re-clearing on a four-year cycle, because it was the best evidence available to Kentucky Power at the time. Based on 20 months of experience of performing Task 2 work, Kentucky Power's best current estimate is that Task 3 work, including any cost increases, can be accomplished at an average cost of $13,365 per mile.

Q. WHY IS THE TASK 3 WORK MORE EXPENSIVE THAN INITIALLY PROJECTED?

A. There are multiple reasons. The projected Task 3 costs used in the 2015 Vegetation Management Plan were estimates based on the Company's experience in performing Task 1 work. While made in good faith, the estimates were just that. With the experience gained over the 20 months of Task 2 work Kentucky Power is better able to estimate the re-growth rates after the rights-of-way have been cleared. That experience indicates that the additional year's growth inherent in a five-year cycle, as opposed to the four-year cycle upon which the estimate was made, increases the cost of the re-clearing work. Kentucky Power now possesses better evidence upon which to estimate the re-growth rates after the rights-of-way have been cleared, and the additional costs associated with the additional growth. In addition, the Company has completed its ramp-up period and has achieved most of the efficiencies to be gained through experience.

Q. ARE THERE ANY OTHER CAUSES?

A. Yes. Annual rainfall for eastern Kentucky has been above average every year since beginning the Plan in 2010. This above average rainfall has led to both a greater amount of vegetation and faster than anticipated regrowth. Further, when trees are trimmed, the tree roots that developed to support the original size of the tree before trimming are left in place. The soil in eastern Kentucky is fertile. When the soil temperatures and moisture content approach ideal, the tree roots are quite capable of supporting fast re-growth of the tree branches. As an example, silver maple tree sprouts may grow up to 15 feet in a single year. A related factor is the amount of vegetation in Kentucky Power's rights-of-way is significantly greater than originally anticipated. For example in 2009, Kentucky Power projected in conjunction with its 2010 Vegetation Management Plan that Task 1 work would involve the removal of 763,000 trees over seven years. Through December 31, 2016, Kentucky Power removed 1,344,104 trees – 76% more than originally projected – as part of its Task 1 work and Task 1 work continues.

Q. WILL THE COMPLETION OF TASK 1 WORK ELIMINATE THE ADDITIONAL COSTS ASSOCIATED WITH THE FERTILITY OF THE COMPANY'S RIGHTS-OF-WAY?

A. Only in part. Although the Task 1 work clears the Company's rights-of-way, the vegetation is expected to grow back more quickly and in greater abundance than originally projected. This regrowth in part can be controlled through Kentucky Power's post-Task 1 herbicide program, but the fact remains that the Company's rights-of-way are capable of supporting larger and denser amounts of vegetation than otherwise would be anticipated.

Q. DO ANY OTHER FACTORS CONTRIBUTE TO THE HIGHER THAN PROJECTED TASK 3 COSTS?

A. Another challenge faced by the Company is the growing customer demand to remove tree debris. As the Company is re-establishing its right-of-ways, many customers want the tree debris cleaned up and removed even though the Company guidelines suggest the debris can remain on the ground in unmaintained areas. The Company is in the process of working with customers on an as needed basis to address these customer demands. Although this additional work arises most often in the case of Task 1 work, it also is increasing the cost of Task 2 and Task 3 work.

Q. PLEASE SUMMARIZE THE COMPANY'S PAST SEVEN YEARS OF EXPERIENCE WITH ITS 2010 AND 2015 VEGETATION MANAGEMENT PLANS.

A. It is worth emphasizing the Plan has evolved since it originally was designed in 2009 as Kentucky Power built on lessons learned. Based on knowledge and experience gained each year as the plan has unfolded Kentucky Power has improved its processes and is better able to estimate costs. Kentucky Power is extremely pleased with the results achieved for our customers to date, and for the expected improvements in the years to come. These results in part have come about because of Commission-approved modifications such as the Company proposes below.

3. 2017 DISTRIBUTION VEGETATION MANAGEMENT PLAN

Q. WHAT CHANGES IS KENTUCKY POWER PROPOSING TO ITS 2015 VEGETATION MANAGEMENT PLAN?

A. The Company is proposing three modifications:

- Kentucky Power estimates that its Task 1 work will be completed no later than March 31, 2018, or nine months earlier than originally projected. It also estimates that Task 2 work will be completed by December 31, 2018. This is six months earlier than projected in connection with the 2015 distribution Vegetation Management Plan.

- Kentucky Power proposes reducing, effective Cycle 1 of the Company January 2018 billing cycle, the distribution Vegetation Management Plan O&M expense in current base rates from $27,661,060 to $21,465,163.

- Kentucky Power also proposes two amendments to its vegetation management and planning reporting requirements. Neither modification will change the Company's overall vegetation management obligation, but will provide the Company with the flexibility necessary to manage its program in the most cost effective manner without limiting the Commission's ability to hold the Company to its obligations under the program.

Q. EXPLAIN THE BASIS FOR THE COMPANY'S CURRENT ESTIMATE THAT IT CAN COMPLETE ITS TASK 1 AND TASK 2 WORK BY MARCH 31, 2018 AND DECEMBER 31, 2018 RESPECTIVELY?

A. Both estimates are based on the work rates attained by the Company over the past two calendar years. In addition, during 2017 Kentucky Power anticipates focusing its vegetation management resources on performing the more expensive Task 1 work. By doing so, Kentucky Power projects that it will complete 1,334 miles of Task 1 work in 2017 (an increase from the 1,094 miles completed in 2016) at a cost of $23,656,060. That would leave approximately 144 miles of Task 1 work to be completed in the first quarter of 2018 at an estimated cost of $2,419,648.

Coincident with the acceleration of Task 1 work, Kentucky Power projects that it will complete 313 miles of Task 2 work (compared to 711 miles completed in 2016) at a cost of $4,005,000. That leaves 1,479 miles of Task 2 work to be completed in 2018 at a cost of $19,219,118. By shifting Task 1 resources to Task 2 work as Task 1 work nears completion, Kentucky Power estimates it can increase its Task 2 work rate and complete the remaining Task 2 work by December 31, 2018.

Based on this schedule, distribution Vegetation Management Plan O&M expenditures will total $27,661,060 in 2017 as shown on Table 9 below compared to the total O&M expenditures in base rates of $27,661,060 as approved in Case No. 2014-00396. Under Kentucky Power's 2017 distribution Vegetation Management Plan, total distribution Vegetation Management Plan O&M expenditures in 2018 will total $21,638,766 as shown in Table 9 below.

Q. **HOW DOES KENTUCKY POWER PROPOSE TO IMPLEMENT ITS 2017 VEGETATION MANAGEMENT PLAN IF IT IS APPROVED?**

A. After completing Task 2 work no later than December 31, 2018, Kentucky Power will begin Task 3 (Five-Year Maintenance Cycle) work effective January 1, 2019. The number of circuit miles of Task 1, Task 2, and Task 3 work projected to be cleared beginning in 2018 under the Company's 2017 distribution Vegetation Management Plan is shown below in Table 8:

Table 8 – 2017 Vegetation Management Plan Work Schedule

2017 Vegetation Management Work Schedule														
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Miles														
Year 1	345					434				1623				
Year 2		942					711				1622			
Year 3			866					313				1623		
Year 4				831					1479				1622	
Year 5					1155									1623
Year 6						1402								
Year 7							1094							
Year 8								1334						
Year 9									144					
Program Miles	345	942	866	831	1155	1836	1805	1647	1623	1623	1622	1623	1622	1623

Task 1 - Initial Re-clear
Task 2 - Interim Re-clear
Task 3 - 5 Year Cycle Trim

Q. WHAT ARE THE PROJECTED EXPENDITURE LEVELS REQUIRED TO FUND THE 2017 VEGETATION MANAGEMENT PLAN?

A. Table 9 below sets out the Company's forecast for Task 1, Task 2, and Task 3 spending through the completion of the first Task 3 cycle (2023).

Table 9 – 2017 Vegetation Management Projected Expenditures

2017 Vegetation Management Projected Expenditures							
	2017	2018	2019	2020	2021	2022	2023
Funds							
Year 1			$21,283,946				
Year 2				$21,472,777			
Year 3	$4,005,000				$21,688,685		
Year 4		$19,219,118				$21,881,312	
Year 5							$22,101,559
Year 6							
Year 7							
Year 8	$23,656,060						
Year 9		$2,419,648					
Program Funds	$27,661,060	$21,638,766	$21,283,946	$21,472,777	$21,688,685	$21,881,312	$22,101,559

(blue)	Task 1 - Initial Re-clear
(yellow)	Task 2 - Interim Re-Clear
(pink)	Task 3 - 5 Year Cycle Trim

Q. PLEASE EXPLAIN HOW KENTUCKY POWER CALCULATED THE AMOUNT OF VEGETATION MANAGEMENT O&M EXPENSES TO BE RECOVERED THROUGH BASE RATES BEGINNING CYCLE 1 OF THE COMPANY'S JANUARY 2018 BILLING CYCLE.

A. Embedded in Kentucky Power's proposed annual revenue requirement is $21,465,163 in distribution Vegetation Management Plan O&M spending in support of the 2017 Vegetation Management Plan. The amount is equal to the average annual vegetation management plan O&M spending over the first three complete years (2018-2020) of the plan. Exhibit EGP-5 provides additional details.

Q. DID THE COMPANY EXAMINE ANY ALTERNATIVES IN LIGHT OF THE HIGHER THAN FORECASTED TASK 3 COSTS?

A. Yes. As demonstrated on Exhibit EGP-5, the Company also examined extending the Task 3 cycle from five years to six years to reduce annual Task 3 Vegetation

Management Plan costs. The projected average annual savings of $1,616,801 with a completed six-year cycle, when compared to the projected annual costs for a completed five-year cycle, are only 7.5 per cent of the completed five-year cycle average annual costs. The price to be paid for these savings is the risk that the increased growth between cycles (the average years of growth between maintenance cycles will increase from 4.94 years of growth to 5.65 years of growth) will produce increased outages inside the rights-of-way. If so, Kentucky Power and its customers will be giving back some of the hard-earned reliability improvements purchased over the past seven years. The aggregate total cost of a complete six-year Task 3 cycle is $120,413,133. The aggregate total cost of a complete five-year Task 3 cycle is $108,428,279. Thus, although the annual cost of the six-year cycle is less than the annual cost of a five-cycle, the extra year of work required for the six-year cycle means the total aggregate cost of a complete six-year cycle is $11,984,854 (approximately 11 per cent) more than the total aggregate cost of a complete five-year cycle.

Q. YOU ALSO INDICATE THE COMPANY PROPOSES TWO CHANGES TO ITS VEGETATION MANAGEMENT REPORTING REQUIREMENTS. WHAT ARE THEY?

A. Kentucky Power currently is required to seek Commission approval prior to deviating more than ten percent from its projected annual vegetation management Operation and Maintenance expenditures in any of the Company's three districts, or on a company-wide basis. The Company proposes to modify the pre-approval requirement for deviations so that pre-approval is required only when the Company's overall annual expenditures are anticipated to deviate from its forecasted projections by more than ten percent. Second, the Company currently is required to plan and manage its vegetation management work and expenditures on two different yearly bases: the vegetation management year, which runs from July 1 through June 30, and a calendar year. The Company proposes to manage its vegetation work and expenditures only on a calendar year basis.

Q. PLEASE EXPLAIN WHY KENTUCKY POWER IS SEEKING APPROVAL TO ELIMINATE THE REQUIREMENT THAT THE COMPANY SEEK PRIOR COMMISSION APPROVAL FOR DEVIATIONS OF MORE THAN TEN PERCENT IN ANY DISTRICT'S ANNUAL PLANNED VEGETATION MANAGEMENT EXPENDITURES.

A. Kentucky Power's vegetation management contractors maintain local crews in each of its three districts. To the greatest extent possible, the local contractor crews are assigned to work only in their home district. Doing so limits the extra expense required to transport crews longer distances to work locations in other districts, to house and feed the crews where required for out-of-district work, as well as the productivity lost to longer travel times. Balanced against this is the need to provide regular work to its contractors' crews so that the Company's contractors can retain their trained and experienced crews. In addition, Kentucky Power sometimes is required to shift contractor crews to other districts to address unexpected conditions in a district in which the contractor's crew is not based. Finally, Kentucky Power sometimes is required to bring in additional resources in the form of roving crews

(crews not assigned to a particular district) to address unanticipated conditions or otherwise to meet its mileage goals.

The additional expenses associated with the use of roving crews, the assignment of locally-based crews to other districts, as well as other measures required to meet the mileage targets for each district can result in a more than ten per cent deviation in planned district expenditures.

Q. HAS KENTUCKY POWER FACED THIS PROBLEM SINCE THE 10% DISTRICT "TRIGGER" WAS AGREED TO BY THE COMPANY?

A. Yes, the Company was required to seek a deviation for 2016. In the first quarter of 2016, Kentucky Power recognized that because of differences in vegetation density among the districts, differences in primary distribution line miles in each of the districts, and differences in the number of crews required to be added and trained in each of the districts, its September 2015 work plan for 2016 would result in Kentucky Power completing the Task 1 work in the Company's Hazard District well in advance of the projected completion dates for Task 1 work in its remaining two districts. This in turn would require, unless the district expenditure targets were modified, the Company's contractors to lay-off a portion of their experienced and trained local work force. Instead of losing these experienced workers, and the hard-earned efficiencies resulting from that experience, Kentucky Power determined that shifting a portion of the local workforce from the Hazard District (which had completed 81% of its Task 1 work) to the adjoining Pikeville District (which had completed 64% of its Task 1 work) would allow the Company's contractors to retain much of their local work force while enabling the Company's three districts to complete Task 1 work at approximately the same time. But doing so would result in deviations of more than 10% from Kentucky Power's projected vegetation management expenditures for both the Pikeville and Hazard Districts. Accordingly, in April 2016 the Company sought (and was granted) authority to increase its projected 2016 Pikeville District vegetation management Operation and Maintenance expenditures by 11% and to reduce its plan Hazard District expenditures by 23%.

Q. ARE YOU SUGGESTING THAT THE COMMISSION DID NOT ACT EXPEDITIOUSLY ON THE COMPANY'S APPLICATIONS?

A. No. To the contrary, the Commission acted quickly on the Company's April 2016 request. Nevertheless, while an application is being prepared and pending the Company may be required to scale back efforts in one district, or postpone ramping up efforts in the other districts. Equally important, even with its best efforts and closest scrutiny, the Company may deviate from its district projections by more than 10%.

Q. IS THE COMPANY PROPOSING THAT IT BE PERMITTED TO DEVIATE FROM ITS ANNUAL WORK PLAN EXPENDITURE TARGET WITHOUT LIMITATION?

A. No. Kentucky Power recognizes the Commission's concern that the Company meet its overall vegetation management plan spending obligation, particularly where base rates are specifically designed to provide funding for the work. The Company also recognizes the Commission should be reasonably informed of any significant deviations in Kentucky Power's annual October 1 of the preceding year work plan. But requiring Kentucky Power to manage annual expenditures on a per-district basis so as not to deviate more than ten per cent does not appear to be the most efficient means of doing so for either the Commission or the Company. Kentucky Power requires the flexibility to shift funds between districts to meet unanticipated developments and to ensure it is able to retain an experienced contractor work force. Kentucky Power requests that the requirement to seek leave to deviate be limited to those instances where it anticipates deviating on a Company-wide basis by plus or minus ten per cent ($2,147,000) from the $21,465,163 to be embedded in base rates. Because the Company will continue to file its work plans and annual reports as required by the Commission's June 22, 2015 Order in Case No. 2014-00396, the Commission can monitor and address any significant disparities on a district basis.

Q. WHY IS THE COMPANY REQUESTING AUTHORITY TO MANAGE ITS VEGETATION MANAGEMENT PROGRAM ON A CALENDAR YEAR?

A. The Company requirement was imposed at the request of Kentucky Power. The provision's purpose was to allow the Company to align its work and funding with the mid-year increased funding. Because the requested increased funding for the 2017 plan, if approved, will become effective at the beginning of a calendar year (Cycle 1 of the January 2018 billing cycle), a separate vegetation management year is no longer required. In addition, Kentucky Power develops work plans and forecasts on a calendar year basis. This also aligns with other external reporting requirements such as the FERC Form 1, which are based the calendar year.

4. <u>THE ONE-WAY BALANCING ACCOUNT AND THE COMPANY'S PROPOSED ADJUSTMENT TO ITS TEST YEAR VEGETATION MANAGEMENT O&M EXPENSES</u>

Q. YOU MENTIONED EARLIER THAT THE SETTLEMENT AGREEMENT THAT ESTABLISHED THE 2015 VEGETATION MANAGEMENT PLAN INCLUDED CERTAIN RATE-RELATED PROVISIONS. WHAT ARE THEY?

A. The 2015 plan also includes a one-way balancing account. Under the 2015 plan, the total annual vegetation management Operation and Maintenance expenses included in base rates is $27,661,060 per year. For purposes of the one-way balancing account, the vegetation management year ends June 30 of each year. Any annual shortfall or excess in vegetation management Operation and Maintenance expenditures is added or subtracted, respectively, from scheduled future expenditures. The Company is required to defer on its books as a regulatory liability any annual shortfall. Any over-expenditure is credited to following years' obligations, but otherwise is not recoverable by the Company.

Q. DID THE SETTLEMENT AGREEMENT AS APPROVED BY THE COMMISSION MAKE FURTHER PROVISION FOR THE ONE-WAY BALANCING ACCOUNT?

A. Yes. If Kentucky Power's cumulative vegetation management Operation and Maintenance expenditures for the four vegetation management years ended June 30, 2019 totaled less than $110,640,240 ($27,661,060 multiplied by four vegetation management years), the shortfall is required to be refunded to the Company's customers or used to reduce the Company's revenue requirement in the next base rate case filed after that date.

Q. WHAT IS THE BALANCE OF THE ONE-WAY VEGETATION MANAGEMENT OPERATION AND MAINTENANCE BALANCING ACCOUNT?

A. There has only been one complete vegetation management year since the one-way balancing account was established effective July 1, 2015. For the 12 months ended June 30, 2016, Kentucky Power Power's Operation and Maintenance expenses of $27,747,265 were $86,205 above target. For the 20 months ended February 28, 2017, Kentucky Power's distribution vegetation management Operation and Maintenance expenditures totaled $45,969,144 or 99.71% of the amount required under the 2015 vegetation management plan. This $132,623 difference for the first 20 months of the 2015 Vegetation Management Program represents slightly less than one day of vegetation management program O&M spending. Kentucky Power anticipates it will continue to meet its projected spending targets.

Q. DID THE 2015 SETTLEMENT AGREEMENT INCLUDE ANY ADDITIONAL RATE-RELATED FEATURES?

A. Yes. The agreement also provided that upon the completion of Task 1 and Task 2 work, and the initiation of Task 3 work (which the Company estimated would be approximately the first billing cycle of the July 2019 billing), certain of the Company's base retail rates would be reduced by an annual amount of $11,780,408. Specifically, the agreement provided:

> Beginning cycle 1 of the July 2019 billing cycle, which is the approximate date the Company anticipates commencing the five-year maintenance cycle, and until the Company's base rates are established in the first base rate case after June 30, 2019, the Company shall reduce the base retail rates for those tariff classes with primary and secondary service offerings by $11,780,408. The reduction shall be allocated solely to tariff classes

> with primary and secondary service offerings, and in the same fashion as the $11,655,900 increase in revenue requirements to fund the Distribution Vegetation Management Program described in this paragraph 8 was allocated, as shown on **EXHIBIT 9**.

The purpose of the provision was to allow the customers to capture without the necessity of a new rate proceeding the O&M savings following the transition in July 2019 to Task 3 only work. That is no longer required as a result of this filing. Kentucky Power proposes to reduce its rates effective Cycle 1 of the January 2018 billin cycle. As a result, O&M expenses are being reduced 24 months early, although the reduction is less than was forecast in 2015.

VI. SMART GRID

Q. PLEASE DESCRIBE "SMART GRID" INVESTMENTS.

A. Smart grid technology uses advanced information tools to improve the efficiency, reliability, and safety of electric distribution system. In its April 13, 2016 order in Case No. 2012-00428, the Commission directed each utility in the Commonwealth subject to its jurisdiction to identify its Smart Grid investments in each rate case. The information provided in this section fulfills the Commission's directive.

Q. WHAT SMART GRID INVESTMENTS HAVE BEEN PLACED IN SERVICE SINCE THE LAST BASE CASE?

A. Kentucky Power installed Volt/Var Optimization technology on 24 circuits. The Volt/VAR technology is in test operation and energy reductions are being evaluated. Kentucky Power also installed Distribution Automation Circuit Reconfiguration technology on nine circuits and is in the process of completing the installation on 19 additional circuits. Kentucky Power utilizes a Distribution Management System that includes Supervisory Control and Data Acquisition (“SCADA”) to provide system analysis of the distribution system. The Data Management System gathers information from electronic devices in the field, including the Distribution Automation Circuit Reconfiguration equipment, and integrates it with the mapping system to provide the status of the automated circuits. It also allows remote operation of devices on those circuits by dispatchers.

Kentucky Power placed in service approximately $4.1 million in capital investment in the Volt/VAR Optimization and related smart grid technology since the last base case. Table 10 is a summary of the Volt/VAR Optimization smart grid investments.

Table 10 – Smart Grid Plant In-Service

Volt/VAR Optimization Project Description	Cost
Circuit Reconfiguration - Line	$3,990,143
Circuit Reconfiguration - Substation	$19,762
Distribution Capacitors	$12,993
Optimization - Line	$74,743
Optimization - Substation	$33,630
Total	**$4,131,271**

Q. WHAT STRATEGIC PLANS ARE BEING CONSIDERED FOR FUTURE RELIABILITY IMPROVEMENT?

A. The electric utility industry is undergoing dramatic and disruptive change that is being driven by customer choice, advanced technology, resource diversity, and unprecedented connectivity. This scenario faced the telecommunications industry twenty years ago, and that industry has changed much since then. Kentucky Power’s strategy is to modernize the power grid to support a reliable, multi-source energy future that will include modern technologies with a focus on building infrastructure and technology to give customers additional choice about how they use energy. The goal is to build a more flexible and resilient distribution power grid that will accommodate local generation of all types, optimize power flows and connect diverse resources while improving grid reliability.

Q. WHAT SMART GRID TECHNOLOGIES ARE BEING CONSIDERED BY KENTUCKY POWER COMPANY?

A. The Smart Grid technologies being considered include:

- Automated Meter Infrastructure
- Volt/Var Optimization
- Distribution-Automation Circuit Reconfiguration
- Faulted Circuit Sensors
- Sensors for Data Collection and fault locating
- Distributed Energy Resources (Renewable, Non-renewable, and Energy Storage) to support isolated rural areas during major outages

Q. WHAT OTHER SMART GRID PROJECTS ARE BEING CONSIDERED BY THE COMPANY TO MODERNIZE ITS DISTRIBUTION GRID AND FURTHER ENHANCE RELIABILITY?

A. The Company is examining projects to extend transmission lines to remote areas and build additional substations and circuits to provide more robust and reliable service to those remote areas. Additional smart gird projects, such as distribution automation circuit reconfiguration technology, can be used in connection with these projects to provide circuit ties between the new and existing circuits to provide back-up sources.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company remains committed to establishing and maintaining a five-year vegetation maintenance cycle for distribution circuits. Since the conception of the Vegetation Management Plan, Kentucky Power has improved and developed the plan based on the knowledge gained in conducting cycle-based vegetation management operations in the challenging terrain found in Kentucky Power's service territory. Kentucky Power also has worked to limit costs and to deploy its resources in a cost-effective fashion. At the 23-month mark since the 2015 Plan was implemented, Kentucky Power anticipates completing Task 1 and Task 2 work ahead of schedule.

The Company also recognizes it must look beyond the completion of the Plan to identify new opportunities for reliability improvement, and develop a strategy going forward that will serve the needs and expectations of our customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Kentucky Power Customer Satisfaction

2016 RESIDENTIAL CUSTOMER SATISFACTION STUDY

SURVEY FIELDED/MANAGED BY THE MSR GROUP, INC.

METHODOLOGY: BLEND OF PHONE BASED AND ONLINE SURVEYS

KENTUCKY POWER SUMMARY DATA: RELIABILITY, RELIABILITY EXPECTATIONS

KENTUCKY POWER'S PERFORMANCE PROVIDING YOU ELECTRICITY WITHOUT INTERRUPTION	TOTAL EXCELLENT AND GOOD RATINGS	JUST OKAY RATINGS	TOTAL POOR AND TERRIBLE RATINGS
Residential (n=605)	79.3%	13.6%	7.1%
Commercial (n=591)	83.1%	11.7%	5.2%

THINKING ABOUT YOUR EXPECTATIONS RELATED TO HAVING RELIABLE ELECTRIC SERVICE, HOW HAVE YOUR EXPECTATIONS CHANGED OVER THE PAST FIVE	TOTAL INCREASED	STAYED ABOUT THE SAME	TOTAL DECREASED
Residential (n=592)	29.7%	58.6%	11.7%
Commercial (n=576)	28.5%	60.1%	11.5%

HOW DO YOU THINK YOUR EXPECTATIONS WILL CHANGE OVER THE NEXT FIVE YEARS?	TOTAL WILL INCREASE	STAY ABOUT THE SAME	TOTAL WILL DECREASE
Residential (n=525)	32.6%	59.0%	8.4%
Commercial (n=526)	29.3%	61.8%	8.9%

HOW HAS KENTUCKY POWER PERFORMED REGARDING YOUR EXPECTATIONS OF THEM DELIVERING RELIABLE ELECTRIC SERVICE?	TOTAL EXCELLENT AND GOOD RATINGS	JUST OKAY RATINGS	TOTAL POOR AND TERRIBLE RATINGS
Residential (n=606)	72.6%	22.4%	5.0%
Commercial (n=591)	67.0%	28.9%	4.1%

Exhibit EGP-2: Map of the KPCo Service Area

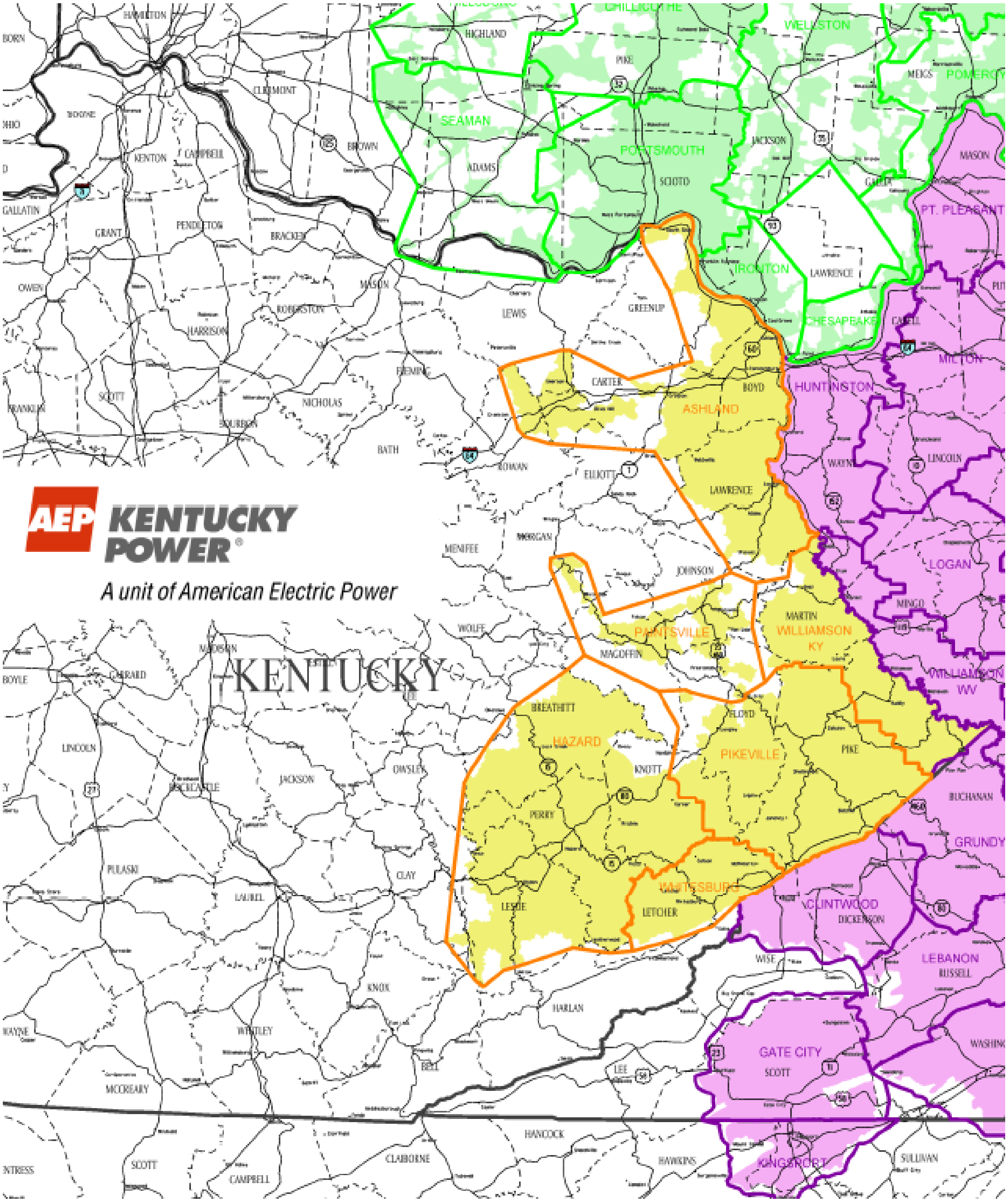
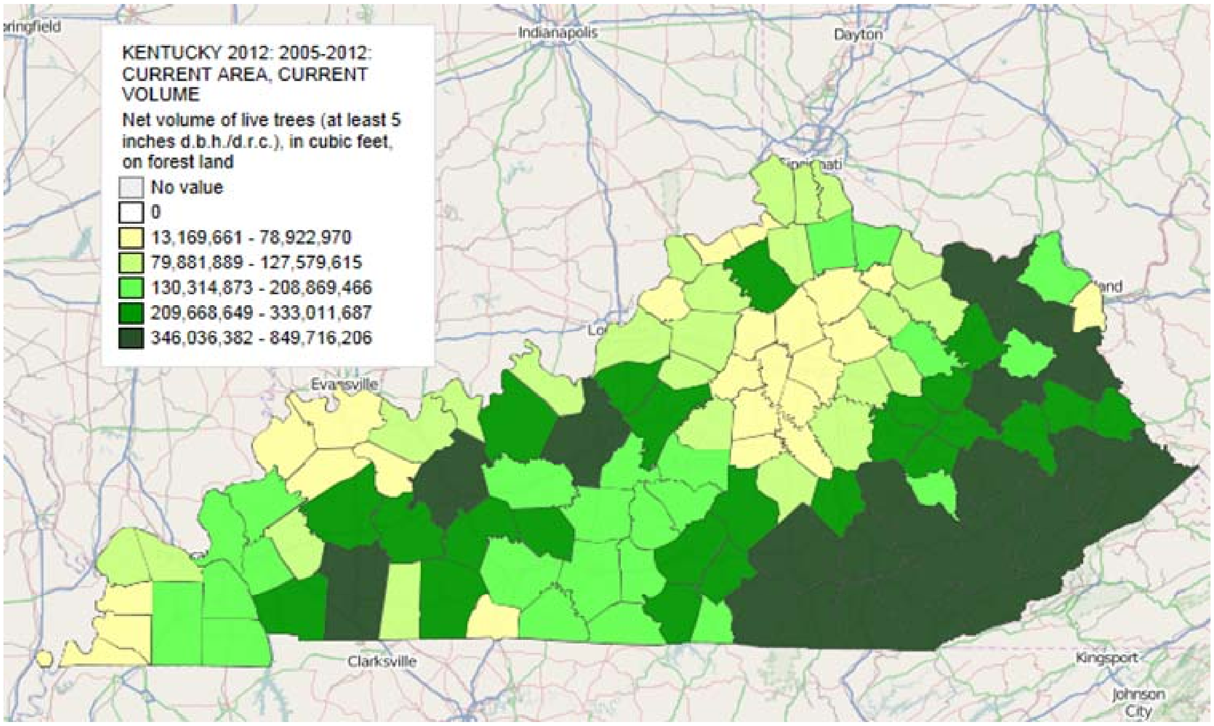


Exhibit EGP-3: Forest Land Distribution for State of Kentucky



STITES & HARBISON PLLC
ATTORNEYS

RECEIVED
MAR 31 2015
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March 31, 2015

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Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Kentucky Power Company's 2012 Vegetation Management Report Filed In Conformity With Commission's June 28, 2010 Order in Case No. 2009-00459

Dear Mr. Derouen:

Please find enclosed and accept for filing the original and ten copies of Kentucky Power Company's 2014 Vegetation Management Report. It is being filed in accordance with the Commission's June 28, 2010 Order in Case No. 2009-00459 and paragraph 5 of the Settlement Agreement approved by that order.

A copy is being served on the Attorney General.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO
cc: Jennifer B. Hans (with enclosure)

RECEIVED
MAR 3 1 2015
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

REPORT OF KENTUCKY POWER COMPANY
IN CONFORMITY WITH PARAGRAPH 5(d)
OF THE UNANIMOUS SETTLEMENT AGREEMENT,
APPENDIX A TO THE COMMISSION ORDER IN
CASE NO. 2009-00459
DATED JUNE 28, 2010

March 31, 2015

In accordance with the Public Service Commission's Order dated June 28, 2010, in Case No. 2009-00459, Kentucky Power compiles the following report regarding its distribution Vegetation Management (VM) Program for the 2014 calendar year:

System Performance for Tree Inside Right-of-Way (SAIFI, CAIDI, and SAIDI)

The first table of reliability information includes Kentucky Power's overall system performance. The second table includes Kentucky Power's system performance for outages comprised of Tree Inside Right-of-Way. These tables include reporting indices for System Average Interruption Frequency Index, the Customer Average Interruption Duration Index, and the System Average Interruption Duration Index for the reporting period, known to the industry as SAIFI, CAIDI, and SAIDI, respectively. Kentucky Power has included these system performance numbers, excluding major events as defined by IEEE standard 1366, for the past five years.

Table 1: Five year reporting indices for all outage cause codes

Year	SAIFI	CAIDI	SAIDI
2010	2.4701	169.39	418.40
2011	3.0854	195.38	602.84
2012	2.4174	189.46	457.99
2013	2.1442	178.49	382.71
2014	2.3736	212.88	505.29

Table 2: Five year reporting indices for only Tree Inside Right-of-Way outage cause code

YEAR	Tree Inside Right-of-Way SAIFI	Tree Inside Right-of-Way CAIDI	Tree Inside Right-of-Way SAIDI
2010	0.3707	190.7	70.68
2011	0.4192	227.4	95.32
2012	0.2562	258.8	66.31
2013	0.2815	184.3	51.88
2014	0.2154	236.3	50.89

Table 2 illustrates an improving trend in the company's reliability indices for tree inside the ROW over the last five years. This improvement, in large part, can be attributed to the improvements in the Vegetation Management Program over the last four and one half years.

2014 Distribution Vegetation Management Work by Circuit

See Attachment 1 for vegetation management work performed on each distribution circuit for 2014. The items reported are re-clearing miles completed, acres of brush cut, acres of brush sprayed, tree growth regulator (soil injection), trees removed, and trees trimmed.

2014 Distribution Operation & Maintenance VM Work by Circuit

See Attachment 1 for the total expenditures for vegetation management work on each distribution circuit in 2014. RWM, AEP's software program for tracking vegetation work and expenditures, does not separately account for O&M and Capital expenditures on a circuit-by-circuit basis. Therefore, the costs in Attachment 1 represent the total O&M and Capital expenditures for each circuit in 2014.

2014 Distribution Vegetation Management Plan – Additional Information

Kentucky Power's 2010 Distribution Vegetation Management Program changed mid-year 2010 from a performance-based maintenance program to a full-circuit maintenance program aimed at moving the Company's VM Program to a cycle-based approach.

In 2014, 1,108 miles of line were re-cleared; Kentucky Power's goal was to re-clear 1,008 miles of line. This was 100 additional miles of completed circuit re-clearing. Please see the Summary of the 2014 Kentucky Power Distribution Vegetation Management Program found on page 4 and 5 of this report for further explanation.

The total 2014 O&M expenditures for the VM Program were $17,567,439, or $329,474 above the $17,237,965 provided for in the May 19, 2010 Unanimous Settlement Agreement:

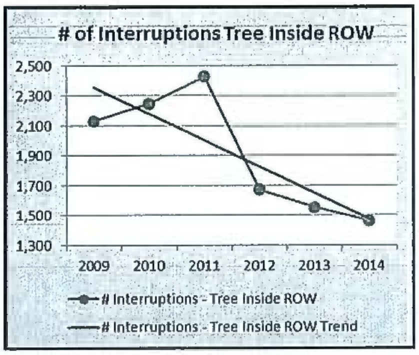
Total 2014 VM O&M	$ 17,567,439
Settlement Agreement Paragraph 5(a)	$ 7,237,965
Settlement Agreement Paragraph 5(b)	$ 10,000,000
Total Settlement Agreement	$ 17,237,965
AMOUNT SPENT ABOVE THE AGREEMENT	**$ 329,474**

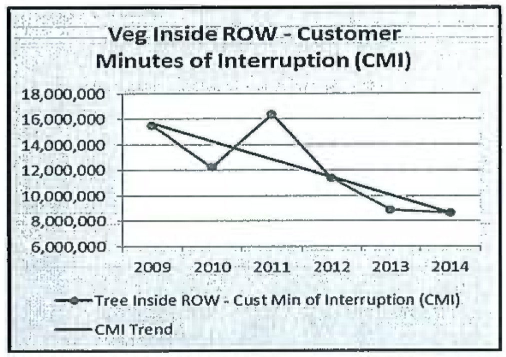
<u>Vegetation Management Program Re-Clearing Update (Since July 2010)</u>

This report marks four and one-half years into the originally projected seven year period for the initial re-clearing of Kentucky Power's distribution system. Under the May 19, 2010 Unanimous Settlement Agreement, Kentucky Power committed to spend during this four and one-half year period $77,736,138 for vegetation management O&M, and invest $9,180,000 in forestry capital. During this same period, Kentucky Power spent $78,274,740 in O&M and $11,967,406 in capital for its Vegetation Management Program. Approximately 52% of the Kentucky Power's distribution system has been re-cleared since July of 2010.

Since July of 2010, the O&M expenditures have produced the following results: 319,889 trees trimmed, 7,806 acres of brush cleared, 10,437 acres sprayed to help control vegetation, and 1,058,096 trees removed. During this time period, Kentucky Power has encountered two main obstacles. First, Kentucky Power found that it significantly underestimated the amount of vegetation in and around its energized facilities. The additional vegetation has increased the cost and time necessary for clearing the facilities. Second, it took much longer than originally anticipated to safely and productively increase the vegetation management workforce to full staffing levels. As a result, Kentucky Power is slightly over the halfway mark in re-clearing its circuits and is behind schedule.

Since July of 2010, Kentucky Power's VM Program has provided benefits to its customers. Over the last four and one half years, the number of tree inside ROW outages (excluding major event days) have been reduced by approximately 40%, while the customer minutes of interruption associated with these events have been reduced by about 47%.





<u>Summary of the 2014 Kentucky Power Distribution Vegetation Management Program</u>

The O&M spending target for 2014 was $17,237,965 and the forestry capital spending target was $2,550,000. Total O&M expenditures for the VM program were $17,567,439 or $329,474 more than the target amount. The forestry capital expenditures were $3,901,140 or $1,351,140 more than the target amount. These additional capital funds were utilized to remove trees larger than 18 inches in diameter, widening rights-of-way, and for tree growth regulator applications (soil injections). The total expenditures for the VM Program were $21,468,579. This exceeded the total spending target for O&M and forestry capital by $1,680,614. See attachment 2 for further explanation of each districts 2014 vegetation management recap.

Costs included in the totals above that were not allocated on a circuit-by-circuit basis include: Internal Labor & Fleet, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract foresters, tree contractor's field supervision, incentive program for tree contractor's employees, and contract clerical work.

The 2014 VM re-clearing plan identified 1,008 miles for full-circuit re-clearing, and 1,108 miles (110%) were re-cleared. The additional 100 miles of completed re-clearing addressed circuits to be re-cleared beginning in 2015, or that were slated for re-clearing in 2014-2015. The VM plan also included 2,545 acres to be sprayed in 2014, and 2,591 acres (102%) were sprayed.

Approximately fifty-two percent of our distribution system has been re-cleared since July of 2010. Given the present budget, the Company estimates that approximately 8 ½ years to complete the initial re-clear of all distribution circuits and migrate to a four-year cycle. This estimate moves the targeted completion date to late 2018.

Kentucky Power Company has continued to review its Vegetation Management Program processes to complete the re-clearing cycle in a safe, cost-efficient, and effective manner.

Revised Kentucky Power Company's 2015 Distribution Vegetation Management Plan

Kentucky Power modified its 2015 Vegetation Management Plan to reflect anticipated efficiency improvements and the fact it was able in 2014 to re-clear 100 circuit miles scheduled for re-clearing in 2015 or 2014-2015. The revised plan will continue to focus on full circuit re-clearing.

The revised 2015 Vegetation Management Plan work and expenditures on a per district basis are:

2015 KENTUCKY POWER DISTRIBUTION VEGETATION MANAGEMENT PLAN

AREA	PLANNED MILES RECLEARING	PLANNED SPRAY ACRES	UNSCHEDULED REACTIVE O&M FUNDING	SCHEDULED O&M FUNDING	TOTAL O&M FUNDING	FORESTRY CAPITAL FUNDING
HAZARD	241	811	$250,000	$3,104,514	$3,354,514	$1,435,920
PIKEVILLE	413	750	$173,913	$8,419,204	$8,593,117	$598,300
ASHLAND	362	450	$35,000	$5,255,334	$5,290,334	$358,980
TOTALS	1,016	2,011	$458,913	$16,779,052	$17,237,965	$ 2,393,200

See Attachment 3 to this report for the revised 2015 Distribution Vegetation Management Plan. Adjustments to the Plan include: 1016 miles of distribution full circuit re-clear, completion of circuit miles planned in 2014 that were not completed, additional circuit miles and circuits added where targets were exceeded in 2014, areas where reliability problems have increased, and field review of proposed rights-of-ways to be re-cleared.

KPSC Case No. 2009-00459
Kentucky Power Company
Attachment 1
Page 1 of 5
Filed March 31, 2015

2014 KY POWER FORESTRY CIRCUIT HISTORY

*Circuit data in **BOLD** represent Full-Circuit Reclearing*

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3000801	**Hayward - Halderman**	**$886,709.22**	**118.0**	**49.0**	**58.0**	**15.97**	**60.18**		**6,348**	**4,180**	**Completed Full Circuit Reclear**
3001401	**Louisa - City**	**$90,423.96**	**10.0**	**0.0**	**10.0**	**7.41**	**0.00**		**646**	**228**	**Completed Full Circuit Reclear**
3002001	**South Shore - Siloam**	**$689,763.76**	**35.0**	**29.0**	**35.0**	**10.31**	**4.50**		**3,724**	**2,510**	**Completed Full Circuit Reclear**
3002002	**South Shore - Distribution**	**$121,372.33**	**9.0**	**9.0**	**9.0**	**1.00**	**0.00**		**784**	**396**	**Completed Full Circuit Reclear**
3002107	**10th Street - West Central**	**$170,886.65**	**17.0**	**8.0**	**8.0**	**9.76**	**7.03**		**695**	**692**	**Completed Full Circuit Reclear**
3003701	**Coalton - US 60 W**	**$134,272.56**	**85.0**	**5.0**	**10.7**	**4.51**	**0.00**		**1,216**	**520**	**began Full Circuit Reclear - to be completed in 2015**
3004301	**Siloam - Distribution**	**$229,868.37**	**22.0**	**22.0**	**12.7**	**2.53**	**0.00**		**1,322**	**670**	**began Full Circuit Reclear - to be completed in 2015**
3007906	**Busseyville - Walbridge**	**$1,068,913.36**	**94.0**	**56.0**	**81.0**	**67.38**	**138.14**	**42**	**10,681**	**5,120**	**Completed Full Circuit Reclear**
3008701	**Cannonsburg - Cannonsburg**	**$1,067,667.64**	**64.0**	**58.0**	**64.0**	**28.66**	**27.87**	**0**	**11,537**	**4,979**	**Completed Full Circuit Reclear**
3116703	**Belhaven - Argillite**	**$249,617.12**	**33.6**	**10.0**	**10.0**	**2.03**	**0.00**		**1,704**	**859**	**Completed Full Circuit Reclear**
3000201	Big Sandy - Fallsburg South	$1,651.51							5		Quality-of-Service Work
3000202	Big Sandy - Burnaugh North	$8,802.85							115	2	Quality-of-Service Work
3000301	Bellefonte - Westwood	$3,266.30							3	3	Quality-of-Service Work
3000303	Bellefonte - Bellefonte	$16,357.75				0.20	10.60		29	16	Quality of Service work; Ground Spray application
3000701	Graysbranch - Graysbranch	$23,608.68				0.00	19.74		1	0	Quality of Service work; Ground Spray application
3000903	Highland - Wurtland	$855.78							1		Quality-of-Service Work
3001002	Hitchins - Willard	$4,013.33					0.88		71		Quality of Service work; Ground Spray application
3001003	Hitchins - Grayson	$331.51							1		Quality-of-Service Work
3001004	Hitchins - EK Road	$5,592.07					1.24		48	24	Quality of Service work; Ground Spray application
3001101	Hoodscreek - Summitt	$19,504.26				0.00	31.00		0	0	Ground Spray application
3001102	Hoodscreek - Rural	$46,240.80				0.00	38.20		14	2	Quality of Service work; Ground Spray application
3001201	Howard Collins - 13th St.	$737.57							1		Quality-of-Service Work
3001202	Howard Collins - 29th St.	$3,981.96					2.10		2		Quality-of-Service Work
3001204	Howard Collins - Summitt	$1,881.55					3.17				Ground Spray application
3001402	Louisa - High Bottom	$2,771.90							4	0	Quality-of-Service Work
3003702	Coalton - Cannonsburg	$8,525.92					3.20		80		Quality of Service work; Ground Spray application
3003703	Coalton - Trace Creek	$48,486.72				6.54	67.22		18	0	Quality of Service work; Ground Spray application
3007903	Busseyville - Louisa	$478.11							1		Quality-of-Service Work
3007904	Busseyville - Torchlight	$23,984.99				0.00	32.11		5	0	Quality of Service work; Ground Spray application
3007905	Busseyville - Mattie	$4,902.21				0.00	17.47		0	0	Ground Spray application
3008001	47th Street - 49th Street	$10,685.90				3.10	16.30		0	5	Quality of Service work; Ground Spray application
3008002	47th Street - 39th Street	$6,099.76				0.00	7.40		1	0	Quality of Service work; Ground Spray application
3008003	47th Street - Catlettsburg	$7,000.09							5	10	Quality-of-Service Work
3008702	Cannonsburg - Rt. 3	$22,503.48				0.30	30.08		24	0	Quality of Service work; Ground Spray application
3010601	Russell - Kenwood	$11,745.69							19	12	Quality-of-Service Work
3103101	Olive Hill - Globe	$7,014.06					2.21		3		Quality of Service work; Ground Spray application
3110902	Wurtland - Greenup	$1,355.44							0	0	Chipping from 2013 trimming
3110903	Wurtland - Rt. 503	$6,146.71				0.10			145		Quality-of-Service Work
3116101	Grayson - Lansdowne	$6,968.53							214	4	Quality-of-Service Work
3116702	Belhaven - Indian Run	$2,404.04							2		Quality-of-Service Work
3117601	Princess - Meade Station	$303.19					0.10				Quality of Service work; Ground Spray application
3117602	Princess - Rt. 180	$6,393.90							123		Quality-of-Service Work

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*Circuit data in **BOLD** represent Full-Circuit Reclearing*

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
	ASHLAND DISTRICT Totals	$5,024,091.53		246.0	298.4	159.8	520.7	42	39,592	20,232	
3300602	**Bluegrass - Hazard**	$51,953.52	11.4	0.0	11.4	16.78	0.44		934	281	Completed Full Circuit Reclear
3301701	**Daisy - Leatherwood**	$585,986.64	88.0	33.3	33.0	95.57	54.25		11,737	2,137	Completed Full Circuit Reclear
3303902	**Leslie - Wooton**	$944,260.29	160.0	94.0	94.0	188.22	12.32		20,897	3,670	Completed Full Circuit Reclear
3308001	**Jackson - South Jackson**	$270,388.23	26.5	26.5	26.5	37.35	0.07		3,350	1,073	Completed Full Circuit Reclear
3308002	**Jackson - Panbowl**	$302,405.28	30.3	30.3	30.3	45.32	0.00		3,668	1,177	Completed Full Circuit Reclear
3308402	**Beckham - Carr Creek**	$68,890.42	116.1	1.0	1.0	1.68	85.42		289	219	Completed Full Circuit Reclear
3308601	**Collier - Upper Rockhouse**	$141,876.18	20.0	0.0	9.0	19.80	34.62		2,050	637	began Full Circuit Reclear - to be completed in 2015
3308603	**Collier - Smoot Creek**	$880,176.75	81.0	46.5	81.0	140.52	0.00		9,703	3,231	Completed Full Circuit Reclear
3309003	**Jeff - Viper**	$634,906.73	47.4	40.0	40.0	83.55	57.23		9,284	2,783	Completed Full Circuit Reclear
3309103	**Whitesburg - Cowan**	$96,196.49	43.0	0.0	8.0	22.53	0.09		1,614	271	Completed Full Circuit Reclear
3309301	**Vicco - Red Fox**	$337,360.50	48.0	31.5	47.0	67.39	91.47		6,647	1,449	began Full Circuit Reclear - to be completed in 2015
3311701	**Shamrock - Shamrock**	$55,664.06	38.3	1.0	0.9	19.13	4.14		1,074	121	began Full Circuit Reclear - to be completed in 2015
3312202	**Engle - Grapevine 34.5**	$910,884.97	95.9	95.9	95.9	190.00	7.56		19,634	3,059	Completed Full Circuit Reclear
3300601	Bluegrass - Walkertown	$28,019.69				4.97	2.64		744	83	Quality of Service work; Ground Spray application
3301101	Chavies - Chavies	$33,505.04				7.96	0.05		924	138	Quality of Service work; Ground Spray application
3301402	Combs - Airport Garden	$18,163.40				0.51	0.83		462	2	Quality of Service work; Ground Spray application
3301102	Chavies - Buckhorn	$7,031.71				1.89			247	11	Quality of Service work
3301401	Combs - Combs	$3,230.18					0.60		31	1	Quality of Service work; Ground Spray application
3302701	Hazard - Black Gold	$14,520.41					3.49		296	6	Quality of Service work; Ground Spray application
3302703	Hazard - Hazard	$4,092.94				0.69	2.06		92	8	Quality of Service work; Ground Spray application
3302704	Hazard - Kenmont	$3,297.64					1.26		1	12	Quality of Service work; Ground Spray application
3303901	Leslie - Hyden	$30,502.00				3.84	0.37		573	134	Quality of Service work; Ground Spray application
3303903	Leslie - Hals Fork	$43,973.61					108.15				Ground Spray Application
3307301	Bulan - Ary-Heiner	$10,114.91					21.64				Ground Spray Application
3307302	Bulan - Ajax-Dwarf	$4,112.26					9.64				Ground Spray Application
3308401	Beckham - Hindman	$8,923.73				0.10	14.96		26	13	Quality of Service work; Ground Spray application
3308403	Beckham - Caney	$9,568.59					22.06				Ground Spray Application
3451202	Beefhide - Dunham	$13,537.10					16.03		8		Quality of Service work; Ground Spray application
3308502	Bonnyman - Hazard	$47,252.57					134.37		20		Quality of Service work; Ground Spray application
3308503	Bonnyman - Big Creek	$10,276.42					13.27		77	5	Quality of Service work; Ground Spray application
3308602	Collier - Lower Rockhouse	$25,429.69				0.18	35.39		49	37	Quality of Service work; Ground Spray application
3309002	Jeff - Jeff	$10,890.64				1.53			192	55	Quality of Service work
3309101	Whitesburg - Whitesburg	$3,547.24					0.31				Ground Spray Application
3309102	Whitesburg - Hospital	$646.70							7		Quality of Service work
3309104	Whitesburg - Crafts Colley	$14,597.81				0.00	14.09		9	4	Quality of Service work; Ground Spray application
3309302	Vicco - Jeff	$35,723.09				0.25	75.15		44	16	Quality of Service work; Ground Spray application
3309901	Slemp - Defeated Cr.	$750.35						19			Quality of Service work
3309902	Slemp - Leatherwood	$10,430.95					21.91				Ground Spray application
3310501	Haddix - Quicksand	$48,868.55				10.65	5.73		1,182	161	Quality of Service work; Ground Spray application
3310502	Haddix - Canoe	$10,845.96				0.64	0.12		93	31	Quality of Service work; Ground Spray application

2014 KY POWER FORESTRY CIRCUIT HISTORY

Circuit data in ***BOLD*** *represent Full-Circuit Reclearing*

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3311101	Stinnett - Redbird	$6,514.62					8.93		17	1	Quality of Service work; Ground Spray application
3311103	Stinnett - Wendover 35kV	$10,209.06					10.19				Ground Spray Application
3311401	Reedy - Deane	$1,465.20					0.01		3		Ground Spray Application
3312201	Engle - Industrial Park 34.5	$57,282.51				2.48	0.03		1,370	55	Quality of Service work; Ground Spray application
3312901	Jenkins - Kona	$1,249.60					0.02				Ground Spray Application
3420001	Softshell - Vest	$3,978.90					0.08		22	17	Quality of Service work; Ground Spray application
3420002	Softshell - Leburn	$47,461.09				0.32	57.39		348	11	Quality of Service work; Ground Spray application
3312902	Jenkins - Jenkins	$19,025.00				0.47	33.56		15	4	Quality of Service work; Ground Spray application
3314401	Mayking - Ermine	$2,604.41					0.01		2		Quality of Service work; Ground Spray application
3314402	Mayking - Millstone	$20,396.75					42.81		2	5	Quality of Service work; Ground Spray application
	HAZARD DISTRICT Totals	$5,902,990.38		400.0	478.0	964.3	1,004.8	19	97,737	20,918	
3150501	**Borderland - Nolan - A**	**$61,351.23**	**18.0**	**18.0**	**18.0**	**22.15**	**0.00**		**1,407**	**89**	**Completed Full Circuit Reclear**
3200204	**Barrenshe - Pounding Mill**	**$128,131.91**	**15.0**	**6.0**	**6.0**	**8.58**	**0.00**		**1,740**	**333**	**Completed Full Circuit Reclear**
3202201	**Lovely - Lovely - A**	**$288,958.46**	**41.0**	**5.0**	**8.0**	**8.86**	**27.58**		**3,450**	**537**	**Completed Full Circuit Reclear**
3202202	**Lovely - Wolf Creek**	**$1,479,871.91**	**59.0**	**58.0**	**57.2**	**112.35**	**1.25**		**22,587**	**4,739**	**began Full Circuit Reclear - to be completed in 2015**
3202203	**Lovely - Mt. Sterling**	**$283,791.95**	**13.3**	**4.1**	**4.1**	**28.55**	**0.00**		**2,492**	**351**	**Completed Full Circuit Reclear**
3400301	**Betsy Layne - Mud Creek**	**$1,064,927.45**	**77.0**	**53.0**	**58.0**	**79.94**	**8.06**		**11,723**	**2,552**	**Completed Full Circuit Reclear**
3400601	**Burton - Bevinsville**	**$235,602.89**	**21.0**	**15.0**	**15.0**	**14.86**	**0.00**		**2,901**	**661**	**Completed Full Circuit Reclear**
3400602	**Burton - Wheelwright**	**$223,935.95**	**21.0**	**5.0**	**5.0**	**7.28**			**1,753**	**457**	**Completed Full Circuit Reclear**
3400901	**Elkhorn City - City**	**$539,631.65**	**29.0**	**29.0**	**29.0**	**40.71**	**1.70**		**6,641**	**1,597**	**Completed Full Circuit Reclear**
3401101	**Falcon - Oil Springs**	**$501,071.41**	**49.0**	**49.0**	**49.0**	**89.13**	**0.00**		**8,151**	**1,586**	**Completed Full Circuit Reclear**
3401103	**Falcon - Burning Fork**	**$63,545.20**	**72.0**	**0.0**	**6.0**	**20.86**	**1.40**		**833**	**190**	**began Full Circuit Reclear - to be completed in 2015**
3402202	**McKinney - Gibson**	**$382,658.19**	**44.0**	**10.0**	**9.9**	**30.00**	**1.37**		**4,954**	**962**	**Completed Full Circuit Reclear**
3403002	**Pikeville - Main Street**	**$68,934.19**	**6.0**	**6.0**	**6.0**	**2.50**	**0.00**		**148**	**296**	**Completed Full Circuit Reclear**
3403201	**Beaver Creek - Ligon**	**$353,463.52**	**80.0**	**35.0**	**15.9**	**27.12**	**4.31**		**3,667**	**759**	**began Full Circuit Reclear - to be completed in 2015**
3403202	**Beaver Creek - Price**	**$517,752.09**	**22.0**	**22.0**	**22.0**	**56.70**	**0.00**		**7,825**	**1,159**	**Completed Full Circuit Reclear**
2153502	**Middle Burning Creek-Naugatuck 12kV**	**$282.23**	**0.7**	**0.7**	**0.7**	**0.00**	**0.00**		**0**	**0**	**Completed Full Circuit Reclear**
3411801	**Johns Creek - Meta**	**$559,740.05**	**167.0**	**46.0**	**21.4**	**52.65**	**118.32**		**8,760**	**738**	**began Full Circuit Reclear - to be completed in 2015**
3400101	Allen - Distribution	$58,454.22				0.14	50.68		4	5	Quality-of-Service work; Ground Spray application
3200201	Barrenshe - Freeburn	$5,334.53				0.01			72	16	Quality-of-Service work
3200202	Barrenshe - Vulcan - A	$1,413.66							31	3	Quality-of-Service work
3200203	Barrenshe - Slate Branch - A	$2,423.95					3.10				Ground Spray application
3200301	Belfry - Belfry	$18,356.74				1.70			224	7	Quality-of-Service work
3200302	Belfry - Toler	$2,511.26							9	1	Quality-of-Service work
3400302	Betsy Layne - Tram 12 KV	$42,828.05				0.31	13.15		254	69	Quality-of-Service work; Ground Spray application
3400303	Betsy Layne - Harold	$49,101.31				0.79	43.17		127	29	Quality-of-Service work; Ground Spray application
3400701	Draffin - Belcher	$52,821.33					55.46				Ground Spray application
3400702	Draffin - Yellow Hill	$10,837.58					8.85				Ground Spray application
3400902	Elkhorn City - Grassy	$1,480.23							2		Quality-of-Service work
3401001	Elwood - Dorton	$1,471.35							3		Quality-of-Service work
3401002	Elwood - Virgie	$2,910.26							1		Quality-of-Service work

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Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3401102	Falcon - Salyersville	$18,016.67				0.00	54.91		5	4	Quality-of-Service work; Ground Spray application
3401301	Fleming - Neon	$6,052.12				0.00	2.76		8	0	Quality-of-Service work; Ground Spray application
3401302	Fleming - McRoberts	$14,342.58					13.20		6	3	Quality-of-Service work; Ground Spray application
3401702	Henry Clay - Regina	$61,165.05				0.25	25.54		176	16	Quality-of-Service work; Ground Spray application
3401703	Henry Clay - Ashcamp	$4,414.16							4	3	Quality-of-Service work
3401801	Index - Distribution	$31,613.30					68.95		5	6	Ground Spray application
3401802	Index - Hospital	$6,753.28					9.00				Ground Spray application
3402001	Keyser - Thompson Road	$8,833.06				0.00			46	23	Quality-of-Service work
3402002	Keyser - Stonecoal	$665.23							10	1	Quality-of-Service work
3402003	Keyser - Mullins	$52,408.91				0.30			799	55	Quality-of-Service work
3402204	McKinney - Maytown	$4,600.61				0.23			99	17	Quality-of-Service work
3402501	Middle Creek - Distribution	$2,872.45							1		Quality-of-Service work
3403001	Pikeville - City	$6,974.65				0.10			40	9	Quality-of-Service work
3403003	Pikeville - Cedar Creek	$16,873.63				0.62			134	2	Quality-of-Service work
3403302	Prestonsburg - University	$6,274.97				0.26			107	11	Quality-of-Service work
3404301	Sidney - Big Creek	$46,290.24				0.38	2.72		381	8	Quality-of-Service work; Ground Spray application
3404302	Sidney - Coburn Mtn.	$979.76							14		Quality-of-Service work
2150103	Sprigg-Sprigg	$20,668.96				0.00	13.06		0	0	Ground Spray application
3407101	Topmost - Dema	$2,869.24							54		Quality-of-Service work
3407103	Topmost - Kite	$339.70				0.11			4		Quality-of-Service work
3408101	Salisbury - Printer	$5,771.95					8.86		3	19	Quality-of-Service work; Ground Spray application
3408102	Salisbury - Black Diamond	$781.03					2.40				Ground Spray application
3408103	Salisbury - Martin	$1,951.77								6	Quality-of-Service work
3408303	Coleman - Peter Creek	$18,056.29				0.53			85	25	Quality-of-Service work
3408304	Coleman - Calloway	$49,975.02				0.25	34.28		93	11	Quality-of-Service work; Ground Spray application
3408402	Kimper - Grapevine	$3,159.41							11		Quality-of-Service work
3409001	W. Paintsville - Paintsville	$2,416.63								9	Quality-of-Service work
3409002	W. Paintsville - Staffordsville	$433.93					2.76				Ground Spray application
3409003	West Paintsville - Plaza	$8,311.60				0.40			187		Quality-of-Service work
3409302	Kenwood - Auxier	$9,237.63							29	5	Quality-of-Service work
3409303	Kenwood - Hagerhill	$1,215.34							6	4	Quality-of-Service work
3409502	Burdine - Levisa Stone	$1,292.32							4		Quality-of-Service work
3409503	Burdine - Jenkins	$11,300.77					15.27				Ground Spray application
3410501	So. Pikeville - Pikeville	$1,484.09				0.05			18		Quality-of-Service work
3410502	So. Pikeville - Island Creek	$67,559.82				0.73	45.75		106	26	Quality-of-Service work; Ground Spray application
3410503	South Pikeville - Hospital	$6,491.34					8.99				Ground Spray application
3410601	E. Prestonsburg - Prestonsburg	$24,609.00							3	5	Quality-of-Service work
3410602	E. Prestonsburg - Lancer	$9,933.00					8.32				Ground Spray application
3411401	Dewey - Inez - A	$185,742.08				0.13	89.19		844	31	Quality-of-Service work; Ground Spray application
3411802	Johns Creek - Raccoon	$23,878.07				0.54			200	2	Quality-of-Service work
3411901	Fords Branch - Shelby	$28,100.99					23.78		13	1	Ground Spray application
3411902	Fords Branch - Robinson Ck	$154,172.89				2.83	150.10		6	0	Quality-of-Service work; Ground Spray application

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	2014 KY POWER FORESTRY CIRCUIT HISTORY					Costs that were not allocated to a circuit include: internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.					
	*Circuit data in **BOLD** represent Full-Circuit Reclearing*										
Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3412901	Weeksbury - Distribution	$31,343.49				0.27			292	63	Quality-of-Service work
3413401	Garrett - Garrett	$9,500.05				0.00			28	15	Quality-of-Service work
3413402	Garrett - Lackey	$1,719.59							4	0	Quality-of-Service work
3417601	New Camp - South Side	$7,857.70					5.76		1		Ground Spray application
3417602	New Camp - Arh- W Wmsn	$158.83					0.10				Ground Spray application
3420102	Mayo Trail-Euclid	$26,866.10				0.52			219	8	Quality-of-Service work
	PIKEVILLE DISTRICT Totals	$8,009,924.05		361.8	331.2	613.7	924.1	0	93,804	17,524	
	KY POWER Totals	$18,937,005.96		1,008	1,108	1,737.8	2,449.6	61	231,133	58,674	

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2014 KENTUCKY POWER DISTRIBUTION VEGETATION MANAGEMENT RECAP

DISTRICT	PLANNED RECLEAR MILES	ACTUAL RECLEAR MILES	PLANNED SPRAY ACRES	ACTUAL SPRAY ACRES	FORESTRY CAPITAL FUNDING	FORESTRY CAPITAL EXPENDITURES	UNSCHEDULED REACTIVE O&M FUNDING	UNSCHEDULED REACTIVE O&M EXPENDITURES
HAZARD	400	478.3	955	1044	$ 1,234,783	$ 1,556,555	$ 397,759	$ 263,854
PIKEVILLE	362	331.2	1020	1025	$ 778,744	$ 1,275,673	$ 179,134	$ 317,988
ASHLAND	246	298.4	570	522	$ 536,473	$ 1,068,912	$ 66,543	$ 28,028
TOTALS	1008	1108	2545	2591	$ 2,550,000	$ 3,901,140	$ 643,436	$ 609,870

DISTRICT	SCHEDULED O&M FUNDING	SCHEDULED O&M EXPENDITURES	TOTAL O&M FUNDING	TOTAL O&M EXPENDITURES	TOTAL VMP FUNDING	TOTAL VMP EXPENDITURES
HAZARD	$ 4,768,994	$ 4,988,810	$ 5,166,753	$ 5,252,664	$ 6,401,536	$ 6,809,219
PIKEVILLE	$ 7,397,463	$ 7,517,090	$ 7,576,597	$ 7,835,078	$ 8,355,341	$ 9,110,751
ASHLAND	$ 4,431,157	$ 4,451,669	$ 4,497,700	$ 4,479,697	$ 5,034,173	$ 5,548,609
TOTALS	$ 16,597,614	$ 16,957,569	$ 17,241,050	$ 17,567,439	$ 19,791,050	$ 21,468,579

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2015 KYPCO DISTRIBUTION VEGETATION MANAGEMENT PLAN

revised 3/23/15

RECLEARING PLAN

DISTRICT	STATION NAME	CIRCUIT NAME	CIRCUIT NUMBER	CIRCUIT MILES	MILES PLANNED	PROJECTED O&M COST per MILE	O&M	Forestry Capital associated with Reclearing	TOTAL COST	COMMENTS
PKV	* Johns Creek	Meta	3411801	167.0	40.7	$20,000	$818,212	$65,457	$883,669	Full Circuit Reclear - to be completed in 2016
PKV	Keyser	Mullins	3402003	30.0	30.0	$20,000	$600,000	$48,000	$648,000	Full Circuit Reclear
PKV	* Pikeville	Cedar Creek	3403003	28.0	28.0	$23,000	$644,000	$51,520	$695,520	Full Circuit Reclear
PKV	Pikeville	City	3403001	23.9	23.9	$23,000	$549,700	$43,976	$593,676	Full Circuit Reclear
PKV	Topmost	Caney	3407102	4.4	4.4	$16,000	$74,058	$5,925	$79,983	Full Circuit Reclear
PKV	Garrett	Garrett	3413401	38.0	38.0	$16,000	$608,000	$48,640	$656,640	Full Circuit Reclear
PKV	Beefhide	Beefhide	3451201	5.4	5.4	$16,000	$86,400	$6,912	$93,312	Full Circuit Reclear
PKV	* Spring Fork	Single Phase	3404002	7.9	7.9	$16,000	$126,400	$10,112	$136,512	Full Circuit Reclear
PKV	* Coleman	Peter Creek	3408303	39.7	39.7	$20,000	$794,000	$63,520	$857,520	Full Circuit Reclear
PKV	* Barrenshe	Pounding Mill	3200204	15.0	9.0	$20,000	$180,000	$14,400	$194,400	Full Circuit Reclear
PKV	* E.Prestonsburg	Lancer	3410602	25.4	25.4	$18,000	$457,200	$36,576	$493,776	Full Circuit Reclear
PKV	* Beaver Creek	Ligon	3403201	80.0	53.0	$20,000	$1,060,000	$84,800	$1,144,800	Complete Full Circuit Reclear
PKV	* Falcon	Burning Fork	3401103	72.0	66.0	$15,823	$1,044,300	$83,544	$1,127,844	Complete Full Circuit Reclear
PKV	Kenwood	Auxier	3409302	41.6	41.6	$16,000	$665,600	$53,248	$718,848	Full Circuit Reclear
ASH	* Coalton	US 60	3003701	88.7	45.2	$16,439	$743,040	$59,443	$802,483	Full Circuit Reclear - to be completed in 2016
ASH	* Busseyville	Torchlight	3007904	98.3	96.3	$6,288	$609,920	$48,794	$658,714	Full Circuit Reclear
ASH	* Big Sandy	Burnaugh-North	3000202	84.4	84.4	$15,086	$1,273,281	$101,862	$1,375,143	Full Circuit Reclear - to be completed in 2016
ASH	Highland	Flatwoods	3000902	13.9	13.9	$16,000	$223,040	$17,843	$240,883	Full Circuit Reclear
ASH	* 47th Street	Catlettsburg	3008003	28.0	28.0	$16,000	$448,000	$35,840	$483,840	Full Circuit Reclear
ASH	* Howard Collins	Floyd	3001203	11.7	11.7	$16,000	$187,200	$14,976	$202,176	Full Circuit Reclear
ASH	Howard Collins	13th St	3001201	13.2	13.2	$16,000	$210,720	$16,858	$227,578	Full Circuit Reclear
ASH	Siloam	Distribution	3004301	22.0	5.0	$16,000	$80,000	$6,400	$86,400	Complete Full Circuit Reclear
ASH	* Highland	Russell	3000901	26.4	26.4	$16,000	$422,400	$33,792	$456,192	Full Circuit Reclear
ASH	Highland	Wurtland	3000903	13.4	13.4	$16,000	$213,760	$17,101	$230,861	Full Circuit Reclear
ASH	Wurtland	Wurtland	3110901	2.9	2.9	$16,000	$45,920	$3,674	$49,594	Full Circuit Reclear
ASH	10th St	6th St	3002101	0.6	0.6	$16,000	$10,240	$819	$11,059	Full Circuit Reclear
ASH	10th St	12th St	3002103	6.9	6.8	$16,000	$108,980	$8,717	$117,677	Full Circuit Reclear
ASH	* 10th St	10-3	3002104	3.8	3.8	$16,000	$60,800	$4,864	$65,664	Full Circuit Reclear
ASH	* 10th St	Midtown	3002105	3.9	3.9	$16,000	$62,400	$4,992	$67,392	Full Circuit Reclear
ASH	10th St	Front St	3002106	1.8	1.8	$16,000	$29,280	$2,342	$31,622	Full Circuit Reclear
ASH	Bellefont	Town Center	300304	2.7	2.7	$16,000	$43,040	$3,443	$46,483	Full Circuit Reclear
HAZ	* Whitesburg	Cowan	3309103	42.7	34.9	$9,038	$315,432	$25,235	$340,666	Complete Full Circuit Reclear
HAZ	* Leslie	Hyden	3303901	88.2	88.2	$10,000	$882,000	$70,560	$952,560	Full Circuit Reclear
HAZ	* Softshell	Leburn	3420002	47.5	28.3	$10,000	$283,000	$22,640	$305,640	Full Circuit Reclear - to be completed in 2016
HAZ	* Collier	Upper Rockhouse	3308601	37.5	28.4	$9,000	$255,600	$20,448	$276,048	Complete Full Circuit Reclear
HAZ	* Vicco	Jeff	3309302	84.7	19.0	$10,000	$190,000	$15,200	$205,200	Begin Full Circuit Reclear-2nd Zone
HAZ	* Haddix	Quicksand	3301501	201.1	42.2	$10,000	$422,000	$33,760	$455,760	Begin Full Circuit Reclear-Hwy 476
	RECLEARING TOTALS		Totals		1016		$14,827,902	$1,186,232	$16,014,135	

Note: * Revised planned circuit miles where miles were cleared in 2014, relibility concerns, or field review.

DISTRIBUTION VEGETATION MANAGEMENT SPRAY PLAN KYPCO 2015		
DISTRICT	ACRES	O&M BUDGET
PKV	750	$360,000
HAZ	811	$432,048
ASH	450	$216,000
Totals	2011	$1,008,048

Kentucky Power Company 2015 Distribution Vegetation Management O&M Forestry Plan-Summary				
ACTIVITY	*Total O&M*	*Pikeville*	*Hazard*	*Ashland*
RECLEARING	$14,827,902	$7,707,870	$2,348,032	$4,772,000
TOTAL SPRAY	$1,008,048	$360,000	$432,048	$216,000
CONTRACT FORESTERS	$240,000	$100,000	$60,000	$80,000
KPI INCENTIVE PROGRAM - Contractor Field Personnel	$350,000	$166,000	$82,000	$102,000
INTERNAL-Existing KY Forestry Staff	$353,102	$85,334	$182,434	$85,334
Sub Total	$16,779,052	$8,419,204	$3,104,514	$5,255,334
Unscheduled/Reactive Maintenance	$458,913	$173,913	$250,000	$35,000
Total O&M	$17,237,965	$8,593,117	$3,354,514	$5,290,334
September 30, 2009 O&M Test Year Level	$7,237,965			
Settlement O&M Incremental Level	$10,000,000			
Total Annual O&M Distribution Vegetation	$17,237,965			
Forestry Capital	$2,393,200			
Total KYPCO Forestry Budget	$19,631,165			
	Reclearing Miles			
Pikeville	413			
Hazard	241			
Ashland	362			
Totals	1,016			

KPSC Case No. 2009-00459
Kentucky Power Company
Attachment 4
Page 1 of 1
Filed March 31, 2015

Kentucky Power Forestry Plan Terminology

Feeder Breaker Zone
Synonymous with Station Zone. Segment of line extending from the circuit station breaker to the first operating device. This zone includes unfused taps, but does not include fused taps.

Full Circuit Reclear
Entire circuit from the station breaker to the end of the circuit.

Recloser Zone
Line segment extending from a specific recloser to the next operating device. This zone includes unfused taps, but does not include fused taps.

Partial Reclear
A portion of the circuit is planned for reclearing.

BID JOB
Planned reclearing work released as an open, lump-sum bid for competing contractors.

Finish Full Circuit Reclear
Reclearing scheduled to complete Full Circuit Reclear that began in the previous year.

2nd Recloser Zone
Line segment beginning at the second operating device beyond the station circuit breaker extending to the next operating device. This zone includes unfused taps, but does not include fused taps.

Quality-of-Service Work
Tree trimming or removal work scheduled for a line segment to address reliability issues. This work does not conform to reclearing specifications (e.g.-Hotspotting).

Cycle Buster Tree
A tree that has to be revisited before the circuit is due for its next cycle trim.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Three Vegetation Management workers performing Task 2 work on Olive Hill – Globe Circuit in Carter County

2015 DISTRIBUTION VEGETATION MANAGEMENT REPORT OF KENTUCKY POWER COMPANY IN CONFORMITY WITH PARAGRAPH 8(d) OF THE SETTLEMENT AGREEMENT, APPENDIX A TO THE COMMISSION'S JUNE 22, 2015 ORDER IN CASE NO. 2014-00396

March 31, 2016

In accordance with the Public Service Commission's Order dated June 22, 2015, in Case No. 2014-00396, Kentucky Power provides the following report regarding its Distribution Vegetation Management ("VM") Program for the 2015 calendar year:

Introduction

The Commission's June 22, 2015 Order in Case No. 2014-00396 approved, with certain modifications unrelated to this report, the Settlement Agreement among Kentucky Power Company, Kentucky Industrial Utility Customers, Inc., and the Kentucky School Boards Association in that case ("Settlement Agreement"). Paragraph 8 of the Settlement Agreement modified the Company's existing VM Program. Generally, paragraph 8 of the Settlement Agreement provided for the following modifications to the then existing VM Program:

- Extended the period to perform the initial re-clearing of the Company's distribution right-of-way through 2018 ("Task 1"). Because the extension of the period for completing Task 1 was finalized subsequent to the Company's October 1, 2014 filing of its 2015 VM Program, the Task 1 mileage targets for 2015 approved as part of the Settlement Agreement are slightly different from those included in the October 1, 2014 VM Program Plan for 2015. In this report the 2015 Task 1 mileage targets are those provided for in the Settlement Agreement;[1]

- Implemented an interim program for the re-clearing of those portions of the Company's distribution right-of-way that were initially re-cleared beginning July 2010. ("Task 2"). The Settlement Agreement provides Task 2 is to be completed June 30, 2019;

- Provided for the initiation of a five-year cycle for VM Program maintenance re-clearing ("Task 3") beginning July 1, 2019;

- Maintained the Task 1 VM Program operation and maintenance and capital spending requirements approved by the Commission in Case No. 2009-00459;

- Provided an additional $10,655,900 in revenue to fund the Task 2-related operation and maintenance activities required under the Settlement Agreement.

[1] The Company exceeded the 2015 Task 1 mileage targets contained in the October 1, 2014 filing and the Settlement Agreement.

- Provided modified total spending requirements for the years 2015-2023. These requirements will decrease beginning in 2019 with the completion of Task 1 and Task 2 and the initiation of Task 3;

- Provided an $11,780,408 reduction of annual base rates beginning July 1, 2019 for those customer classes funding the VM Program;

- Established a one-way balancing account for annual deviations of total VM Program expenditures from the $27,661,060 included in annual base rates beginning July 1, 2015.

2015 Work Performed And Expenditures

During calendar 2015, Kentucky Power exceeded both its VM expenditure and VM mileage cleared targets.

A. 2015 Distribution VM Expenditures

The total O&M spending target for calendar year 2015 was $22,327,777. Total O&M expenditures for the VM program were $23,067,891 or $740,114 (3.3%) more than the target amount.

2015 Task 1 expenditures were budgeted at $8,618,983 for the first six months and 17,237,965 for the calendar year. Actual 2015 Task 1 O&M expenditures were $9,447,174 ($828,191 above target) during the first six months and $18,932,943 ($1,694,978 above target) for the calendar year.

Task 2 was initiated July 1, 2015. 2015 Task 2 O&M expenditures were budgeted at $5,089,812. Actual 2015 Task 2 O&M expenditures were $4,134,948 ($954,864 less than budget).

Kentucky Power's 2015 Task 2 expenditures were less than budgeted because it was able to make greater use of the less expensive "local" crews to perform Task 2 work than originally projected. These crews, which originally were scheduled to perform Task 1 work during the second half of 2015, became available to perform Task 2 work because of the greater than projected amount of Task 1 work completed during the first half of the year. This in turn was due to the higher level of Task 1 expenditures during the first half of the year. In addition, the

Task 1 work is moving to some of the less heavily overgrown, and less expensive to clear, circuits.

Notwithstanding the lower than budgeted level of Task 2 expenditures, Kentucky Power exceeded its 2015 Task 2 mileage target.

The 2015 forestry capital spending target was $2,371,472; forestry capital expenditures for calendar year 2015 were $5,699,748 ($3,328,276 above target). These additional capital funds were utilized to remove trees larger than 18 inches in diameter, widening rights-of-way, and for tree growth regulator applications (soil injections).

The 2015 total capital and O&M expenditures for the VM Program were $28,767,639. This exceeded the 2015 expenditure target for O&M and forestry capital by $4,068,390.

Please see Table 1 for further information on VM expenditures.

Table 1: Kentucky Power Budgeted Expenses for 2015 Revised VM Program						
Targeted Task VM Program	Jan - Jun		July - Dec		Year 2015	
	Budget	Actual	Budget	Actual	Budget	Actual
Task 1	$ 8,618,982	$ 9,447,174	$ 8,618,983	$ 9,485,769	$ 17,237,965	$ 18,932,943
Task 2	-	-	$ 5,089,812	$ 4,134,948	$ 5,089,812	$ 4,134,948
Task 3	-	-	-	-	-	-
VM Program Dollars	$8,618,982	$9,447,174	$13,708,795	$13,620,717	$22,327,777	$23,067,891

B. 2015 VM Mileage Cleared

During calendar year 2015 the Company was projected to perform 987 miles of Task 1 work. The 2015 target for Task 2 work, which commenced July 1, 2015, was 371 miles. During 2015 Kentucky Power performed 1436 miles of Task 1 work (449 miles or 45% above target) and 434 miles of Task 2 work (63 miles or 17% above target). The VM plan also included 2,011 acres to be sprayed in 2015, and 1,967 acres (97.8%) were sprayed.

Since the beginning of the VM program in 2010, Kentucky Power has completed approximately 70% of the Task 1 work.

Further information concerning 2015 VM mileage cleared is presented in Table 2:

Table 2: Targeted/Completed Mileage for Vegetation Management Program		
Distribution Vegetation Work Plan	Year - 2015	
	Targeted Mileage	Completed Mileage
Task 1	987	1436
Task 2	371	434
Task 3	-	-
Veg Program Miles	**1358**	**1870**

Since it began July 2010, Kentucky Power's VM program has trimmed 395,888 trees, cleared 9,366 acres of brush, sprayed 12,607 acres to control vegetation, and removed 1,338,402 trees.

C. 2015 Distribution VM Work by Circuit

Attachment 1 details the Task 1 VM work and expenditures by circuit. Attachment 2 similarly reports the 2015 (July 1 to December 31) Task 2 VM work and expenditures by circuit. Both attachments provide the number of miles of circuit completed, acres of brush cut, acres of brush sprayed, tree growth regulator (soil injection), trees removed, and trees trimmed.

O&M and capital expenditures are not accounted for on a circuit-by-circuit basis. The costs in Attachment 1 and 2 represent the total O&M and Capital expenditures for each circuit. Also unallocated on a circuit-by-circuit basis are: Internal Labor & Fleet, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract foresters, tree contractor's field supervision, incentive program for tree contractor's employees, and contract clerical work expenses.

D. Measures Of Improvement In System Reliability (SAIFI, CAIDI, SAIDI, and CMI)

Table 3 provides total system reliability indices for Kentucky Power's overall system for 2010 (when the VM Program began) through December 31, 2015. Table 4 provides reliability indices limited to Tree Inside of Right-of-Way outages for the same period.

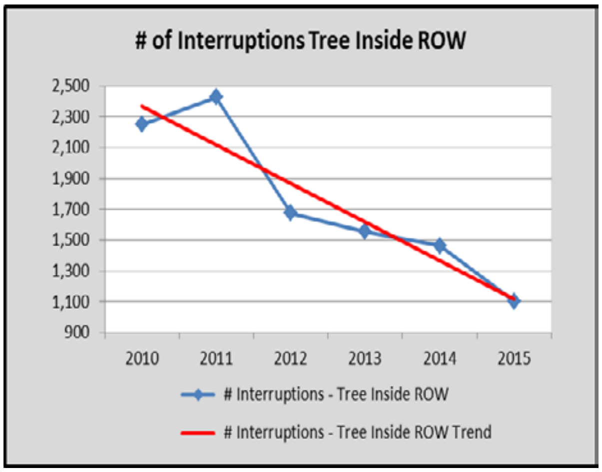
The indices included in both Table 3 and Table 4 are System Average Interruption Frequency Index ("SAIFI"), the Customer Average Interruption Duration Index ("CAIDI"), and the System Average Interruption Duration Index ("SAIDI") for each reporting period. Excluded from the calculation of the indices are major events as defined by IEEE standard 1366.

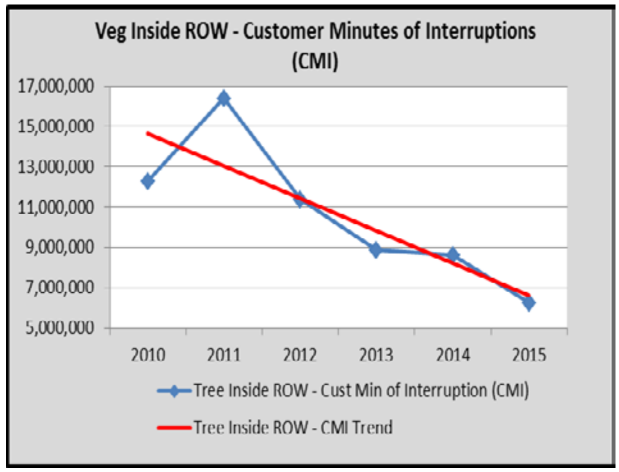
Table 3: Six Year Reporting Indices for all Outage Cause Codes			
Year	**SAIFI**	**CAIDI**	**SAIDI**
2010	2.4701	169.39	418.4
2011	3.0854	195.38	602.84
2012	2.4174	189.46	457.99
2013	2.1442	178.49	382.71
2014	2.3736	212.88	505.29
2015	2.4639	189.85	467.77

Table 4: Six Year Reporting Indices for Tree Inside Right-of-Way Outage Cause Codes			
YEAR	**Tree Inside Right-of-Way SAIFI**	**Tree Inside Right-of-Way CAIDI**	**Tree Inside Right-of-Way SAIDI**
2010	0.3707	190.7	70.68
2011	0.4192	227.4	95.32
2012	0.2562	258.8	66.31
2013	0.2815	184.3	51.88
2014	0.2154	236.3	50.89
2015	0.1782	207.6	37.00

Table 4 in particular is useful in assessing the efficacy of the Company's VM Program because the VM Program focuses on inside right-of-way vegetation management. The 2015 Tree Inside Right-Of-Way SAIFI, CAIDI, and SAIDI metrics are 38%, 5%, and 40%, respectively, below the average Tree Inside Right-Of-Way SAIFI, CAIDI, and SAIDI metrics for the period 2010-2015.

Since the VM Program began in July 2010, the annual number of tree inside ROW outages (excluding major event days) has been reduced by approximately 51% from 2,248 to 1,102; the annual number of customer minutes of interruption associated with these events has been reduced by approximately 49% from 12,247,282 to 6,236,943.





E. <u>VM Program-To-Date Expenditures</u>

Beginning with the commencement of the VM Program in July 2010, Kentucky Power committed to expend $99,898,620 on VM O&M through December 31, 2015. Through that period the Company expended $101,342,631 or $1,444,011 (1.4%) more than its commitment. Kentucky Power's VM Program capital spending commitment during the same period was $11,220,000. It exceeded that target by 57% ($6,447,154).

Kentucky Power Company continues to review its VM Program processes to permit it to transition in a safe, cost-efficient, and effective manner to a five-year cycle on or before July 1, 2019.

F. <u>Balancing Account</u>

Under paragraph 8(e)(ii) of the Settlement Agreement, a one-way balancing account was established beginning July 1, 2015. The account, which requires the Company to make $27,661,060 in VM O&M expenditures during each July 1 through June 30 period ("Vegetation Management Year"), will continue until base rates are next established. The balancing account will track any shortfall or over-expenditure in Vegetation Management Year VM O&M expenditures.

When Company base rates are next established any cumulative shortfall in VM O&M expenditures will be refunded to customers or used to reduce the Company's revenue requirement. The Company may not recover any cumulative over-expenditure.

The Company's VM O&M expenditures through December 31, 2015 (50% of the Vegetation Management Year) were $13,620,717. These expenditures represents 49.2% of the July 1, 2015 through June 30, 2016 Vegetation Management Year requirement. Kentucky Power anticipates meeting the $27,661,060 target by the close of the Vegetation Management Year.

G Revised Kentucky Power Company's 2016 Distribution VM Plan

Kentucky Power revised its 2016 Vegetation Management Plan (filed September 30, 2015) to reflect anticipated efficiency improvements and the fact that in 2015 the Company was able to re-clear 512 circuit miles scheduled for re-clearing in 2016 or 2015-2016. The revised plan will continue to focus on full circuit re-clearing (Task 1) and interim re-clearing (Task 2).

The revised 2016 Kentucky Power Distribution VM Plan projected expenditures for the three districts in its service territory for Task 1 and Task 2 are shown in Table 5. The revised 2016 Kentucky Power Distribution targeted mileage by district is shown in Table 6.

Table 5: 2016 Kentucky Power Company Revised Distribution VM O&M Forestry Plan (Task 1 & Task 2) - Summary

ACTIVITY	***Total O&M***	***Ashland***	***Hazard***	***Pikeville***
Total Circuit Re-clearing	**$24,573,850**	*$7,457,217*	*$4,142,475*	*$12,974,158*
Total Spray	**$1,200,000**	*$288,000*	*$432,000*	*$480,000*
Contract Foresters	**$310,993**	*$103,664*	*$103,664*	*$103,665*
KPI INCENTIVE PROGRAM - Contractor Field Personnel	**$586,774**	*$195,591*	*$195,591*	*$195,592*
INTERNAL - Existing KY Forestry Staff	**$556,002**	*$185,334*	*$155,334*	*$215,334*
Unscheduled/Reactive Maintenance	**$436,979**	*$35,000*	*$239,066*	*$162,913*
Total O&M	**$27,664,598**	***$8,264,806***	***$5,268,130***	***$14,131,662***
Forestry Capital	**$2,433,956**			
Total KYPCO Forestry Budget	**$30,098,554**			

Table 6: 2016 Kentucky Power Revised Distribution Targeted Mileage			
District	**Planned Miles Initial Re-clear Task 1**	**Planned Miles Interim Re-clear Task 2**	**Total VM Target**
Ashland	394	210	604
Hazard	221	255	476
Pikeville	585	306	891
Totals	**1200**	**771**	**1971**

See Attachment 3 to this report for the 2016 revised Distribution VM Plan on a circuit-by-circuit basis. Adjustments to the Plan (Task 1 and Task 2) include: completion of circuit miles planned in 2015 that were not completed, additional circuit miles and circuits added where targets were exceeded in 2015, areas where reliability problems have increased, and forestry review of proposed rights-of-ways to be re-cleared.

The Commission's June 22, 2015 Order in Case No. 2014-00396 directed Kentucky Power to seek leave of the Commission prior to "altering any proposed spending that deviates by 10 percent or more from the total amount or within each Division as set forth in an annual filing on September 30."[2] The revised 2016 Distribution VM Plan proposes to increase total O&M spending by $3,538 (0.0128%) and total forestry capital spending by $911,631 (59.88%). By district, Kentucky Power proposes to modify O&M spending under the revised plan as follows: expenditures in the Ashland district will increase $117,789 (1.45%); expenditures in the Hazard district will decrease by $1,498,375 (-22.14%); and expenditures in the Pikeville district will increase $1,384,124 (10.86%).

The proposed shift in spending between the three districts will permit Kentucky Power to maintain the Task 2 mileage targets by district, maintain the Task 1 mileage target for the Hazard district, and increase the Task 1 mileage targets for the Ashland (50 miles or 14.53%) and Pikeville (164 miles or 38.95%) districts . The shift in spending will permit the Company to deploy its resources efficiently, move the individual districts to similar states of completion of

[2] Order, *In the Matter of: Application of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its2014 Environmental Compliance Plan; An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief*, Case No. 2014-00396 at 77 (Ky. P.S.C. June 22, 2015)

Task 1 work, and begin the Task 3 five year-cycle in each of the three districts at approximately the same time.

Kentucky Power will promptly file its request for leave to deviate from its September 2015 plan.

KPSC Case No. 2014-00396
In Conformity with Paragraph 8(d)
Of the Settlement Agreement
Attachment 1
Page 1 of 3
Filed March 31, 2016

2015 KY POWER FORESTRY CIRCUIT HISTORY Task 1 - Ashland District *Circuit data in BOLD represent Full-Circuit Reclearing*						Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.					
Circuit Number	**Circuit Name**	**Cost (includes O&M and Capital)**	**Total Line Miles**	**Reclearing Miles Planned**	**Reclearing Miles Complete**	**Brush Cut (acres)**	**Brush Spray (acres)**	**Tree Growth Regulator**	**Tree Removal**	**Tree Trim**	**COMMENTS**
2206403	**South Neal - Whites Creek**	**$8,856.02**	**38.8**	**0.0**	**20.0**	**0.0**	**31.5**		**4**	**70**	**Started Full Circuit Re-clear - completion in 2016**
3000202	**Big Sandy - Burnaugh North**	**$894,819.60**	**84.4**	**84.4**	**84.5**	**52.3**	**133.1**		**9,382**	**4,731**	**Completed Full Circuit Re-clear**
3000302	**Bellefonte - Flatwoods**	**$78,288.57**	**3.2**	**0.0**	**3.2**	**0.0**	**0.0**		**739**	**197**	**Completed Full Circuit Re-clear**
3000304	**Bellefont - Town Center**	**$27,870.24**	**2.7**	**2.7**	**2.7**	**0.0**	**0.0**		**616**	**64**	**Completed Full Circuit Re-clear**
3000901	**Highland - Russell**	**$302,040.13**	**24.3**	**26.4**	**24.3**	**5.0**	**0.0**		**1,375**	**1,060**	**Completed Full Circuit Re-clear**
3000902	**Highland - Flatwoods**	**$215,388.06**	**13.9**	**13.9**	**13.9**	**7.5**	**0.0**		**2,128**	**1,290**	**Completed Full Circuit Re-clear**
3000903	**Highland - Wurtland**	**$191,247.17**	**13.4**	**13.4**	**13.4**	**2.3**	**0.0**		**1,156**	**634**	**Completed Full Circuit Re-clear**
3001201	**Howard Collins - 13th St.**	**$207,286.39**	**13.2**	**13.2**	**13.2**	**2.5**	**0.0**		**832**	**976**	**Completed Full Circuit Re-clear**
3001203	**Howard Collins - Floyd St.**	**$144,260.84**	**11.1**	**11.7**	**11.1**	**2.3**	**0.0**		**583**	**735**	**Completed Full Circuit Re-clear**
3001402	**Louisa - High Bottom**	**$167,205.43**	**13.0**	**0.0**	**10.0**	**0.0**	**0.0**		**25**	**1**	**Started Full Circuit Re-clear - completion in 2016**
3002101	**10th Street - 6th St.**	**$1,139.67**	**0.6**	**0.6**	**0.6**	**0.1**	**0.0**		**23**	**4**	**Completed Full Circuit Re-clear**
3002103	**10th Street - 12th St.**	**$103,636.87**	**6.8**	**6.8**	**6.8**	**3.5**	**0.0**		**692**	**585**	**Completed Full Circuit Re-clear**
3002104	**10th Street - 10-3**	**$50,694.40**	**3.0**	**3.8**	**3.0**	**0.2**	**0.0**		**84**	**172**	**Completed Full Circuit Re-clear**
3002105	**10th Street - Midtown**	**$18,515.92**	**3.7**	**3.9**	**3.7**	**0.0**	**0.0**		**14**	**19**	**Completed Full Circuit Re-clear**
3002106	**10th Steet - Front Street**	**$8,676.82**	**1.8**	**1.8**	**1.8**	**0.4**	**0.0**		**258**	**15**	**Completed Full Circuit Re-clear**
3003701	**Coalton - US 60 W**	**$1,024,919.00**	**88.7**	**45.2**	**75.0**	**24.5**	**44.6**		**8,755**	**4,576**	**Started Full Circuit Re-clear - completion in 2016**
3004301	**Siloam - Distribution**	**$165,334.00**	**22.7**	**5.0**	**5.0**	**1.5**	**0.0**		**1,426**	**608**	**Finish Full circuit Reclear - carry over from 2014**
3007904	**Busseyville - Torchlight**	**$436,705.67**	**98.3**	**98.3**	**97.0**	**69.9**	**125.3**		**12,535**	**4,149**	**Completed Full Circuit Re-clear**
3007905	**Busseyville - Mattie**	**$165,443.52**	**91.0**	**0.0**	**23.0**	**0.0**	**0.0**		**2,106**	**839**	**Started Full Circuit Re-clear - completion in 2016**
3008003	**47th Street - Catlettsburg**	**$260,186.68**	**26.8**	**28.0**	**26.8**	**9.9**	**15.8**		**3,425**	**1,223**	**Completed Full Circuit Re-clear**
3010602	**Russell - Bear Run**	**$0.00**	**13.0**	**0.0**	**3.0**	**0.0**	**28.9**		**467**	**126**	**Started Full Circuit Re-clear - completion in 2016**
3010603	**Russell - Ashland Oil**	**$4,491.86**	**1.1**	**0.0**	**1.1**	**0.0**	**0.0**		**29**	**6**	**Completed Full Circuit Re-clear**
3110901	**Wurtland - Wurtland**	**$5,136.75**	**2.9**	**2.9**	**2.9**	**0.0**	**0.0**		**5**	**16**	**Completed Full Circuit Re-clear**
3116102	**Grayson - Dixie Park**	**$279,382.62**	**33.5**	**0.0**	**20.6**	**0.0**	**0.0**		**1,353**	**1,162**	**Started Full Circuit Re-clear - completion in 2016**
3117601	**Princess - Meade Station**	**$357,805.41**	**46.8**	**0.0**	**34.2**	**16.2**	**0.0**		**3,449**	**2,066**	**Started Full Circuit Re-clear - completion in 2016**
3000303	Bellefonte - Bellefonte	$980.99	56.2	0.0	1.9	0.0	0.0		11	0	Quality of Service Work
3000801	Hayward - Halderman	$13,481.04	117.0	0.0	1.0	0.0	0.0		405	26	Quality of Service Work
3000802	Hayward - Lawton	$728.31	36.3	0.0	0.0	0.0	0.0		0	0	Work Planning for spray - defferred
3001002	Hitchins - Willard	$114,620.17	152.0	0.0	0.0	38.4	0.0		1,387	0	Widening
3001003	Hitchins - Grayson	$954.83	48.4	0.0	0.0	0.0	0.0		1	0	Capital removal
3001004	Hitchins - EK Road	$323.84	31.4	0.0	0.0	0.0	0.0		13	0	Quality-of-Service Work
3001101	Hoods Creek - Summitt	$219.39	22.7	0.0	0.0	0.0	0.0		2	0	Quality-of-Service Work
3001102	Hoods Creek - Rural	$2,104.06	47.0	0.0	0.0	0.2	0.0		30	0	Quality-of-Service Work
3001401	Louisa - City	$2,574.35	10.0	0.0	0.0	0.0	0.0		6	9	Quality-of-Service Work
3003702	Coalton - Cannonsburg	$13,390.76	23.3	0.0	0.0	0.2	17.8		75	15	Quality of Service work; Ground Spray application
3003703	Coalton - Trace Creek	$362.40	82.5	0.0	0.0	0.0	0.0		0	2	Quality-of-Service Work
3007903	Busseyville - Louisa	$3,202.53	44.0	0.0	0.0	0.0	0.0		83	11	Quality-of-Service Work
3007906	Busseyville - Walbridge	$150,040.76	94.0	0.0	0.0	3.8	207.5		239	135	Ground and Aerial Spray, Widening
3008701	Cannonsburg - Cannonsburg	$37,445.61	63.0	0.0	0.0	0.0	0.0		91	9	Widening
3008702	Cannonsburg - Rt. 3	$1,779.95	100.0	0.0	0.0	0.2	0.0		94	18	Danger tree removal
3010601	Russell - Kenwood	$660.53	20.7	0.0	0.0	0.0	0.0		25	0	Quality-of-Service Work
3110902	Wurtland - Greenup	$1,994.09	50.8	0.0	0.0	0.0	2.3		0	0	Quality-of-Service Work
3110903	Wurtland - Rt. 503	$1,877.74	46.0	0.0	0.0	0.0	0.0		42	0	Quality-of-Service Work
3116101	Grayson - Lansdowne	$37,385.86	36.1	0.0	0.0	0.0	0.0		653	20	Widening
	ASHLAND DISTRICT Totals	**$5,503,458.85**		**362.0**	**503.7**	**240.9**	**606.8**	**0**	**54,618**	**25,569**	

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2015 KY POWER FORESTRY CIRCUIT HISTORY						Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.					
Task 1 - Hazard District											
	Circuit data in BOLD represent Full-Circuit Reclearing										
Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3303901	**Leslie - Hyden**	**$977,121.66**	**88.2**	**88.2**	**85.6**	**62.3**	**11.9**		**20,985**	**3,062**	**Completed Full Circuit Re-clear**
3308601	**Collier - Upper Rockhouse**	**$129,377.66**	**37.4**	**28.4**	**28.4**	**22.6**	**0.8**		**1,770**	**689**	**Completed Full Circuit Re-clear**
3309103	**Whitesburg - Cowan**	**$383,980.22**	**43.1**	**34.9**	**43.1**	**56.8**	**0.1**		**2,265**	**1,118**	**Completed Full Circuit Re-clear**
3309302	**Vicco - Jeff**	**$263,107.03**	**84.7**	**19.0**	**23.2**	**46.2**	**33.7**		**7,149**	**1,014**	**Started Full Circuit Re-clear**
3309902	**Slemp - Leatherwood**	**$248,130.08**	**71.3**	**0.0**	**18.0**	**0.0**	**1.6**		**7,766**	**789**	**Started Full Circuit Re-clear**
3310501	**Haddix - Quicksand**	**$1,084,048.07**	**202.0**	**42.2**	**55.0**	**125.9**	**4.4**		**12,899**	**1,393**	**Started Full Circuit Re-clear**
3310502	**Haddix - Canoe**	**$137,354.32**	**125.0**	**0.0**	**16.0**	**0.3**	**4.2**		**2,777**	**561**	**Started Full Circuit Re-clear**
3401302	**Fleming - McRoberts**	**$148,426.89**	**30.2**	**0.0**	**10.0**	**0.0**	**0.4**		**881**	**471**	**Started Full Circuit Re-clear**
3420001	**Softshell - Vest**	**$250,302.22**	**59.0**	**0.0**	**18.0**	**1.8**	**43.5**		**5,671**	**654**	**Started Full Circuit Re-clear**
3420002	**Softshell - Leburn**	**$509,919.04**	**49.5**	**28.3**	**49.5**	**52.6**	**45.8**		**8,188**	**2,539**	**Completed Full Circuit Re-clear**
3300601	Bluegrass - Walkertown	$529.85	29.0	0.0	0.0	0.0	0.0		1	0	Quality-of-Service Work
3300602	Bluegrass - Hazard	$11,802.63	11.4	0.0	0.0	1.3	0.0		352	4	Widening
3301101	Chavies - Chavies	$25,475.26	69.1	0.0	0.0	0.9	2.4		186	7	Quality-of-Service Work, Widening
3301401	Combs - Combs	$8,642.34	9.0	0.0	0.0	0.0	0.0		16	0	Quality-of-Service Work
3301402	Combs - Airport Gardens	$79,635.24	43.0	0.0	0.0	0.0	2.8		739	0	Widening
3301701	Daisy - Leatherwood	$9,297.23	88.0	0.0	0.0	0.0	1.1		136	0	Ground Spray, Widening
3303902	Leslie -Wooton	$167,320.44	134.0	0.0	0.0	6.2	309.7		149	39	Ground Spray, Widening
3303903	Leslie - Hals Fork	$8,983.75	76.0	0.0	0.0	0.0	6.1		0	0	Ground Spray - Basal
3307301	Bulan - Ary Hiner	$1,324.43	54.0	0.0	0.0	0.0	1.7		0	0	Ground Spray - Basal
3307302	Bulan - Ajax Dwarf	$1,476.27	40.0	0.0	0.0	0.0	1.8		0	0	Ground Spray - Basal
3308002	Jackson - Panbowl	$26,013.31	31.6	0.0	0.0	0.0	2.6		2	0	Ground Spray - Basal
3308401	Beckham - Hindman	$56,305.18	102.0	0.0	0.0	0.0	8.9		477	0	Widening, Ground Spray
3308402	Beckham - Carr Creek	$58,961.71	111.0	0.0	0.0	0.0	0.0		918	26	Widening
3308502	Bonnyman - Hazard	$5,369.12	43.4	0.0	0.0	0.0	3.4		0	0	Ground Spray - Basal
3308503	Bonnyman - Big Creek	$8,256.23	84.0	0.0	0.0	0.0	2.0		51	0	Ground Spray - Basal, Widening
3308602	Collier - Lower Rockhouse	$8,244.25	66.0	0.0	0.0	0.0	1.2		60	9	Widening
3308603	Collier - Smoot Creek	$57,660.03	81.0	0.0	0.0	0.4	40.4		192	15	Ground Spray, Widening
3309001	Jeff - Boone Ledge	$13,526.82	5.0	0.0	0.0	0.0	0.6		159	20	Widening
3309002	Jeff - Jeff	$16,514.28	5.7	0.0	0.0	0.0	0.3		14	3	Widening
3309003	Jeff - Viper	$3,556.50	43.5	0.0	0.0	0.0	1.8		0	0	Ground Spray - Basal
3309101	Whitesburg - Whitesburg	$862.96	10.0	0.0	0.0	0.0	0.0		3	0	Quality-of-Service Work
3309301	Vicco - Red Fox	$7,824.94	48.5	0.0	0.0	1.2	0.0		113	20	Widening
3311101	Stinnett - Redbird	$5,463.95	121.0	0.0	0.0	0.0	3.5		1	0	Ground Spray - Basal
3311102	Stinnett - Beech Fork	$2,729.78	10.0	0.0	0.0	0.0	3.3		0	0	Ground Spray - Basal
3311103	Stinnett - Wendover	$2,463.70	36.3	0.0	0.0	0.0	2.4		0	0	Ground Spray - Basal
3311401	Reedy - Deane	$8,842.35	44.5	0.0	0.0	0.0	14.5		0	0	Ground Spray - Basal
3311701	Shamrock - Shamrock	$33,266.25	54.0	0.0	0.0	0.0	12.1		0	0	Ground Spray - Basal
3312201	Engle - Industrial Park	$15,039.97	4.1	0.0	0.0	0.0	32.9		18	0	Ground Spray, Widening
3312202	Engle - Grapevine	$91,644.86	101.2	0.0	0.0	0.0	146.5		1	0	Ground Spray
3312901	Jenkins - Kona	$2,565.63	26.0	0.0	0.0	0.0	0.2		6	0	Quality-of-Service Work
3312902	Jenkins - Jenkins	$1,999.55	23.8	0.0	0.0	0.0	0.1		0	3	Quality-of-Service Work
3401301	Fleming - Neon	$4,951.64	21.0	0.0	0.0	0.0	0.5		17	0	Quality-of-Service Work
3409503	Burdine - Jenkins	$1,838.44	8.2	0.0	0.0	0.0	0.3		7	4	Quality-of-Service Work
	HAZARD DISTRICT Totals	**$4,880,156.08**		**241.0**	**346.8**	**378.5**	**749.5**	**0.0**	**73,969.0**	**12,440.0**	

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2015 KY POWER FORESTRY CIRCUIT HISTORY

Task 1 - Pikeville District

Circuit data in BOLD represent Full-Circuit Reclearing

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3200204	**Barrenshe - Pounding Mill**	**$217,908.77**	**16.0**	**9.0**	**16.0**	**19.7**	**0.0**		**2,915**	**683**	**Completed Full Circuit Re-clear**
3401102	**Falcon - Salyersville**	**$323,715.68**	**44.0**	**0.0**	**43.0**	**56.3**	**0.0**		**3,636**	**1,356**	**Completed Full Circuit Re-clear**
3401103	**Falcon - Burning Fork**	**$471,130.90**	**72.0**	**66.0**	**72.0**	**111.7**	**0.1**		**7,026**	**2,141**	**Completed Full Circuit Re-clear**
3402003	**Keyser - Mullins**	**$329,713.23**	**30.0**	**30.0**	**30.0**	**34.3**	**0.0**		**2,590**	**1,155**	**Completed Full Circuit Re-clear**
3403001	**Pikeville - City**	**$242,523.44**	**23.9**	**23.9**	**11.0**	**0.0**	**0.0**		**869**	**197**	**Started Full Circuit Re-clear - completion in 2016**
3403003	**Pikeville - Cedar Creek**	**$492,755.36**	**28.0**	**28.0**	**28.0**	**0.5**	**1.2**		**3,384**	**667**	**Completed Full Circuit Re-clear**
3403201	**Beaver Creek - Ligon**	**$819,562.42**	**80.0**	**53.0**	**58.0**	**42.1**	**44.6**		**8,404**	**1,740**	**Completed Full Circuit Re-clear**
3404002	**Spring Fork - Single Phase**	**$84,809.16**	**11.0**	**7.9**	**11.0**	**26.8**	**0.0**		**2,943**	**127**	**Completed Full Circuit Re-clear**
3407102	**Topmost - Caney**	**$2,130.26**	**4.4**	**4.4**	**0.0**	**0.0**	**0.0**		**0**	**0**	**Full Circuit Re-clear - defferred**
3408303	**Coleman - Peter Creek**	**$1,050,715.02**	**40.0**	**39.7**	**40.0**	**56.1**	**2.7**		**14,058**	**3,057**	**Completed Full Circuit Re-clear**
3408304	**Coleman - Calloway**	**$928,445.66**	**36.0**	**0.0**	**36.0**	**31.5**	**0.0**		**14,052**	**2,316**	**Completed Full Circuit Re-clear**
3409302	**Kenwood - Auxier**	**$384,466.11**	**41.6**	**41.6**	**39.0**	**68.3**	**0.0**		**5,959**	**1,868**	**Started Full Circuit Re-clear - completion in 2016**
3410602	**E. Prestonsburg - Lancer**	**$261,061.42**	**25.4**	**25.4**	**25.0**	**36.5**	**0.0**		**5,127**	**1,130**	**Completed Full Circuit Re-clear**
3411401	**Dewey - Inez A**	**$451,131.89**	**171.0**	**0.0**	**27.5**	**65.1**	**0.6**		**5,546**	**1,452**	**Started Full Circuit Re-clear - completion in 2016**
3411801	**Johns Creek - Meta**	**$1,840,905.02**	**167.0**	**40.7**	**80.1**	**136.5**	**11.5**		**26,190**	**3,411**	**Started Full Circuit Re-clear**
3411802	**Johns Creek - Raccoon**	**$394,115.82**	**84.0**	**0.0**	**25.7**	**0.0**	**0.0**		**4,622**	**655**	**Started Full Circuit Re-clear - completion in 2016**
3413401	**Garrett - Garrett**	**$355,970.94**	**38.0**	**38.0**	**38.0**	**67.1**	**0.0**		**6,069**	**1,396**	**Completed Full Circuit Re-clear**
3451201	**Beefhide - Beefhide**	**$66,305.47**	**5.4**	**5.4**	**5.4**	**13.2**	**0.0**		**1,381**	**25**	**Completed Full Circuit Re-clear**
2150103	Sprigg - Sprigg	$1,690.04		0.0	0.0	0.0	1.8		0	0	Ground Spray
3150501	Borderland - Nolan A	$835.31		0.0	0.0	0.0	0.0		12	0	Widening
3150502	Borderland - Chattaroy	$3,616.30		0.0	0.0	1.0	0.0		137	0	Quality-of-Service Work
3200301	Belfry - Belfry	$17,533.19		0.0	0.0	2.6	0.0		189	0	Quality-of-Service Work
3200302	Belfry - Toler	$4,775.95		0.0	0.0	0.3	0.0		73	0	Quality-of-Service Work
3202201	Lovely - Lovely A	$67,027.36		0.0	0.0	0.0	45.7		0	1	Ground Spray
3202202	Lovely - Wolf Creek	$103,782.28		0.0	0.0	0.3	36.3		320	82	Ground Spray, carry-over from 2014, work complete
3202203	Lovely - Mt. Sterling	$61,248.71		0.0	0.0	0.0	36.9		1	0	Ground Spray
3400101	Allen - Distribution	$526.20		0.0	0.0	0.0	0.0		10	0	Quality-of-Service Work
3400301	Betsy Layne - Mud Creek	$2,593.15		0.0	0.0	0.0	0.0		23	8	Quality-of-Service Work
3400302	Betsy Layne - Tram	$7,386.21		0.0	0.0	0.2	0.0		61	6	Quality-of-Service Work
3400303	Betsy Layne - Harold	$4,582.33		0.0	0.0	0.0	0.0		38	1	Quality-of-Service Work
3400601	Burton - Bevinsville	$45,460.23		0.0	0.0	0.0	43.7		0	0	Ground Spray
3400602	Burton - Wheelwright	$55,884.37		0.0	0.0	0.0	62.0		0	0	Ground Spray
3400701	Draffin - Belcher	$1,099.41		0.0	0.0	0.0	0.0		2	0	Quality-of-Service Work
3400901	Elkhorn City - City	$53,562.21		0.0	0.0	0.0	60.3		3	0	Ground Spray
3401001	Elwood - Dorton	$99,038.80		0.0	0.0	0.0	0.0		320	0	Widening
3401702	Henry Clay - Regina	$39,271.37		0.0	0.0	0.0	50.2		6	0	Ground Spray
3401801	Index - Distribution	$25,817.87		0.0	0.0	0.0	0.0		329	26	Widening
3401802	Index - Hospital	$966.06		0.0	0.0	0.0	0.0		8	0	Quality-of-Service Work
3402002	Keyser - Stonecoal	$199.43		0.0	0.0	0.0	0.0		9	0	Quality-of-Service Work
3402202	McKinney - Gibson	$58,505.83		0.0	0.0	0.0	80.6		31	1	Ground Spray
3402801	Painstville - City	$1,034.00		0.0	0.0	0.0	0.0		1	0	Quality-of-Service Work
3403202	Beaver Creek - Price	$56,357.76		0.0	0.0	0.0	18.0		2	0	Ground Spray
3403701	Russell Fork - Little Beaver	$734.19		0.0	0.0	0.0	0.0		3	0	Quality-of-Service Work
3403801	Second Fork - Distribution	$2,989.00		0.0	0.0	0.0	0.0		90	0	Quality-of-Service Work
3407101	Topmost - Dema	$8,517.59		0.0	0.0	0.1	0.0		115	1	Quality-of-Service Work
3408103	Salisbury - Martin	$3,726.72		0.0	0.0	0.0	0.0		15	5	Quality-of-Service Work
3408402	Kimper - Grapevine	$5,750.77		0.0	0.0	0.0	0.0		75	7	Quality-of-Service Work
3409003	West Paintsville - Plaza	$846.46		0.0	0.0	0.0	0.0		0	6	Quality-of-Service Work
3409301	Kenwood - W. Van Lear	$2,366.12		0.0	0.0	0.0	0.0		3	0	Quality-of-Service Work
3409303	Kenwood - Hager Hill	$461.87		0.0	0.0	0	0		3	0	Quality-of-Service Work
3410503	South Pikeville - Hospital	$15,431.54		0.0	0.0	0	0		0	0	Planning for ground spray
3410601	E. Prestonsburg - Prestonsburg	$8,034.72		0.0	0.0	0.0	0.0		12	0	Quality-of-Service Work
3411901	Fords Branch - Shelby	$1,208.07		0.0	0.0	0.0	0.0		10	1	Quality-of-Service Work
3411902	Fords Branch - Robinson Ck	$1,958.64		0.0	0.0	0.0	0.0		3	0	Quality-of-Service Work
3412901	Weeksbury - Distribution	$47,924.14		0.0	0.0	0.1	48.6		25	0	Ground Spray
3413402	Garrett - Lackey	$2,011.21		0.0	0.0	0.0	0.0		3	4	Quality-of-Service Work
3414501	Consol - Coal Co	$6,110.65		0.0	0.0	0.8	0.0		138	33	Quality-of-Service Work
3417601	New Camp - South Side	$36,433.96		0.0	0.0	0.0	17.5		0	0	Ground Spray
3420102	Mayo Trail - Euclid	$12,712.41		0.0	0.0	0.0	0.0		161	4	Quality-of-Service Work
	PIKEVILLE DISTRICT Totals	**$9,587,379.00**		**413.0**	**585.7**	**771.1**	**562.3**	**0.0**	**117,002**	**23,562**	
	KY POWER Task 1 Totals	**$19,970,993.93**		**1,016.0**	**1,436.2**	**1,390.5**	**1,918.6**	**0**	**245,589**	**61,571**	

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2015 KY POWER FORESTRY CIRCUIT HISTORY

Ashland District - Task 2

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	Tree Removal	Tree Trim	COMMENTS
3000201	Big Sandy - Fallsburg South	$292,425.41	158.0	24.3	29.3	1.9	73.1		999	1,357	Started interim re-clear
3000701	Graysbranch - Graysbranch	$116,766.65	66.0	24.3	27.7	2.8	0.0		620	440	Started interim re-clear
3103101	Olive Hill - Globe	$272,761.67	117.0	24.3	27.6	7.6	0.0		1,397	914	Started interim re-clear
	ASHLAND DISTRICT Totals	**$681,953.73**		**72.9**	**84.6**	**12.3**	**73.1**	**0**	**3,016**	**2,711**	
	Hazard District - Task 2										
3302701	Hazard - Blackgold	$325,278.60	55.0	55.0	55.0	0.0	3.5		5,511	841	Completed interim re-clear
3302703	Hazard - Hazard	$92,110.95	11.2	11.2	11.2	0.0	0.0		449	505	Completed interim re-clear
3309104	Whitesburg - Crafts Colley	$234,733.64	27.6	17.4	27.2	0.0	3.5		3,542	1,234	Interim re-clear
3309902	Slemp - Leatherwood	$23,686.62	71.2	0.0	4.0	0.0	3.5		601	147	Started interim re-clear
3309903	Slemp - Beech Fork	$2,697.09	1.7	1.7	1.7	0.0	0.0		75	3	Completed interim re-clear
3309904	Slemp - Royal Diamond	$4,339.21	2.2	2.2	2.2	0.0	0.0		282	8	Completed interim re-clear
3311101	Stinnett - Redbird	$123,631.67	120.7	0.0	16.0	0.0	3.5		2,806	571	Started interim re-clear
3311102	Stinnett - Beech Fork	$21,916.02	9.5	8.0	8.0	0.0	3.3		228	26	Started interim re-clear
3314401	Mayking - Ermine	$192,059.81	28.8	18.6	28.6	5.9	21.1		2,284	1,013	Interim re-clear
3314402	Mayking - Millstone	$98,196.20	55.0	55.0	55.0	24.9	17.4		2,633	1,320	Completed interim re-clear
	HAZARD DISTRICT Totals	**$1,118,649.81**		**169.1**	**208.9**	**30.8**	**55.8**	**0**	**18,411**	**5,668**	
	Pikeville District - Task 2										
3200202	Barrenshe - Vulcan A	$11,592.67	45.0	0.0	0.0	0.0	0.0		0	0	Started interim re-clear
3400101	Allen - Distribution	$2,293.76	27.8	0.0	0.0	0.0	0.0		0	0	Started interim re-clear
3401002	Elwood - Virgie	$13,332.03	73.8	0.0	0.0	0.0	0.0		0	0	Started interim re-clear
3404302	Sidney - Coburn Mtn.	$1,104,469.42	47.0	47.0	47.0	103.5	5.6		6,497	3,315	Completed interim re-clear
3409002	W. Paintsville - Staffordsville	$441,628.83	46.7	22.0	33.0	4.3	0.0		3,050	1,290	Started interim re-clear
3409401	Feds Creek - Feds Creek	$394,769.56	41.0	41.0	41.0	17.6	94.6		1,882	559	Completed interim re-clear
3409402	Feds Creek - Lick Creek	$273,518.86	18.0	18.0	18.0	1.1	21.8		1,846	856	Completed interim re-clear
3974101	Big Rock - Conaway	$7,066.47	1.0	1.0	1.0	0.0	0.0		15	29	Completed interim re-clear
	PIKEVILLE DISTRICT Totals	**$2,248,671.60**		**129.0**	**140.0**	**126.5**	**122.0**	**0**	**13,290**	**6,049**	
	Total Kentucky Power - Task 2	**$4,049,275.14**		**371**	**433.5**	**169.6**	**250.9**	**0**	**34,717**	**14,428**	

KPSC Case No. 2014-00396
In Conformity with Paragraph 8(d)
Of the Settlement Agreement
Attachment 3
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2016 Kentucky Power Revised Distribution VM PLAN

Task 1 Full Circuit Re-Clearing Plan

Costs that are not allocated to a circuit include; internal labor & fleet costs, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

DISTRICT	STATION NAME	CIRCUIT NAME	CIRCUIT NUMBER	CIRCUIT LINE MILES	MILES PLANNED	PROJECTED O&M COST per MILE	O&M	FORESTRY CAPITAL ASSOCIATED WITH RE-CLEARING	TOTAL COST	COMMENTS
ASH	Ashland	25th St	3000101	1.4	1.4	$11,300	$15,820	$1,740	$17,560	Full Circuit Re-clear
ASH	Ashland	29th St	3000102	6.8	6.8	$11,300	$76,840	$8,452	$85,292	Full Circuit Re-clear
ASH	Ashland	14th St	3000103	1.3	1.3	$11,300	$14,690	$1,616	$16,306	Full Circuit Re-clear
ASH	Ashland	3rd St	3000104	0.2	0.2	$11,300	$2,260	$249	$2,509	Full Circuit Re-clear
ASH	Ashland	1st St	3000105	1.7	1.7	$11,300	$19,210	$2,113	$21,323	Full Circuit Re-clear
ASH	Princess	Meade	3117601	46.8	12.6	$11,300	$142,380	$15,662	$158,042	Complete Full Circuit Re-clear
ASH	Princess	Rt 180	3117602	23.1	12.2	$11,300	$137,860	$15,165	$153,025	Full Circuit Re-clear
ASH	Howard Collins	Summit	3001204	25.4	25.4	$11,300	$287,020	$31,572	$318,592	Full Circuit Re-clear
ASH	Grayson	Dixie Park	3116102	33.5	12.9	$11,300	$145,770	$16,035	$161,805	Complete Full Circuit Re-clear
ASH	Grayson	Lansdowne	3116101	35.3	35.3	$11,300	$398,890	$43,878	$442,768	Full Circuit Re-clear
ASH	Hitchens	Grayson	3001003	48.0	8.8	$11,300	$99,440	$10,938	$110,378	Begin Full Circuit Re-clear
ASH	Belhaven	Argillite	3116703	27.6	27.6	$11,300	$311,880	$34,307	$346,187	Full Circuit Re-clear
ASH	Belhaven	Indian Run	3116702	18.9	18.9	$11,300	$213,570	$23,493	$237,063	Full Circuit Re-clear
ASH	Belhaven	Diedrich	3116701	8.9	8.9	$11,300	$100,570	$11,063	$111,633	Full Circuit Re-clear
ASH	Russell	Bear Run	3010602	13.0	10.0	$11,300	$113,000	$12,430	$125,430	Complete Full Circuit Re-clear
ASH	Russell	Ashland Oil	3010603	1.1	1.1	$11,300	$12,430	$1,367	$13,797	Full Circuit Re-clear
ASH	Busseyville	Louisa	3007903	44.0	44.0	$11,300	$497,200	$54,692	$551,892	Full Circuit Re-clear
ASH	Busseyville	Mattie	3007905	92.5	69.5	$11,300	$785,350	$86,389	$871,739	Complete Full Circuit Re-clear
ASH	South Neal	Whites Creek	2206403	38.8	18.8	$11,300	$212,440	$23,368	$235,808	Complete Full Circuit Re-clear
ASH	Hoods Creek	Rural	3001102	47.2	32.2	$11,300	$363,860	$40,025	$403,885	Full Circuit Re-clear
ASH	Louisa	High Bottom	3001402	13.0	3.0	$11,300	$33,900	$3,729	$37,629	Complete Full Circuit Re-clear
ASH	Coalton	US 60 W	3003701	88.7	13.7	$11,300	$154,810	$17,029	$171,839	Complete Full Circuit Re-clear
ASH	Coalton	Trace Creek	3003703	82.5	27.7	$11,300	$313,010	$34,431	$347,441	Begin Full Circuit Re-clear
	Ashland District (Task 1) Totals				**394.0**		**$4,452,200**	**$489,742**	**$4,941,942**	
HAZ	Bluegrass	Walkertown	3300601	28.5	15.8	$10,560	$166,848	$33,370	$200,218	Full Circuit Re-clear
HAZ	Chavies	Chavies	3301101	68.1	20.0	$10,560	$211,200	$42,240	$253,440	Begin Full Circuit Re-clear
HAZ	Vicco	Jeff	3309302	84.7	29.8	$10,560	$314,688	$62,938	$377,626	Continue Full Circuit Re-clear
HAZ	Slemp	Defeated Creek	3309901	13.4	13.4	$10,560	$141,504	$28,301	$169,805	Full Circuit Re-clear
HAZ	Slemp	Leatherwood	3309902	71.3	27.7	$10,560	$292,512	$58,502	$351,014	Continue Full Circuit Re-clear
HAZ	Haddix	Quicksand	3310501	202.0	10.0	$10,560	$105,600	$21,120	$126,720	Continue Full Circuit Re-clear
HAZ	Haddix	Canoe	3310502	125.0	24.8	$10,560	$261,888	$52,378	$314,266	Continue Full Circuit Re-clear
HAZ	Fleming	Neon	3401301	20.5	20.5	$10,560	$216,480	$43,296	$259,776	Complete Full Circuit Re-clear
HAZ	Fleming	McRoberts	3401302	30.2	20.3	$10,560	$214,368	$42,874	$257,242	Complete Full Circuit Re-clear
HAZ	Softshell	Vest	3420001	59.0	38.7	$10,560	$408,672	$81,734	$490,406	Continue Full Circuit Re-clear
	Hazard District (Task 1) Totals				**221.0**		**$2,333,760**	**$466,752**	**$2,800,512**	
PKV	Dewey	Inez	3411401	171.0	143.5	$14,420	$2,069,218	$186,230	$2,255,448	Complete Full Circuit Reclear
PKV	Johns Creek	Raccoon	3411802	84.0	58.3	$14,420	$840,665	$75,660	$916,325	Complete Full Circuit Re-clear
PKV	Betsy Layne	Tram	3400302	35.0	35.0	$14,420	$504,687	$45,422	$550,109	Full Circuit Re-clear
PKV	Henry Clay	Ashcamp	3401703	43.0	43.0	$14,420	$620,045	$55,804	$675,849	Full Circuit Re-clear
PKV	Henry Clay	Regina	3401702	110.0	49.3	$14,420	$710,888	$63,980	$774,868	Begin Full Circuit Re-clear
PKV	South Pikeville	Pikeville	3410501	10.0	10.0	$14,420	$144,196	$12,978	$157,174	Full Circuit Re-clear
PKV	Topmost	Dema	3407101	37.0	37.0	$14,420	$533,527	$48,017	$581,544	Full Circuit Re-clear
PKV	Topmost	Kite	3407103	25.0	25.0	$14,420	$360,491	$32,444	$392,935	Full Circuit Re-clear
PKV	Topmost	Caney	3407102	4.4	4.4	$14,420	$63,446	$5,710	$69,157	Full Circuit Re-clear
PKV	Pikeville	City	3403001	23.9	12.9	$14,420	$186,013	$16,741	$202,755	Complete Full Circuit Re-clear
PKV	Kenwood	Auxier	3409302	41.6	2.6	$14,420	$37,491	$3,374	$40,865	Complete Full Circuit Re-Clear
PKV	Mckinney	Maytown	3402204	36.0	36.0	$14,420	$519,107	$46,720	$565,827	Full Circuit Re-clear
PKV	Garrett	Lackey	3413402	35.0	35.0	$14,420	$504,687	$45,422	$550,109	Full Circuit Re-clear
PKV	E. Prestonsburg	Prestonsburg	3410601	7.0	7.0	$14,420	$100,937	$9,084	$110,022	Full Circuit Re-clear
PKV	Prestonsburg	City	3403301	7.0	7.0	$14,420	$100,937	$9,084	$110,022	Full Circuit Re-clear
PKV	Kenwood	W. Vanlear	3409301	19.0	19.0	$14,420	$273,973	$24,658	$298,631	Full Circuit Re-clear
PKV	Index	Distribution	3401801	54.0	54.0	$14,420	$778,661	$70,079	$848,740	Full Circuit Re-clear
PKV	Middle Creek	Distribution	3402501	6.0	6.0	$14,420	$86,518	$7,787	$94,304	Full Circuit Re-clear
	Pikeville District (Task 1) Totals				**585.0**		**$8,435,490**	**$759,194**	**$9,194,684**	
	FULL-CIRCUIT RE-CLEARING (TASK 1) TOTALS				**1200.0**		**$15,221,450**	**$1,715,688**	**$16,937,138**	

2016 Kentucky Power Revised Distribution VM PLAN

Task 2 Interim Re-Clearing Plan

Costs that are not allocated to a circuit include; internal labor & fleet costs, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, contract clerical work, contract foresters, tree contractors' field supervision, and incentive program for tree contractor's employees.

DISTRICT	STATION NAME	CIRCUIT NAME	CIRCUIT NUMBER	CIRCUIT LINE MILES	MILES PLANNED	PROJECTED O&M COST per MILE	O&M	FORESTRY CAPITAL ASSOCIATED WITH INTERIM RE-CLEAR	TOTAL COST	COMMENTS
ASH	Big Sandy	Fallsburg	3000201	159.9	58.1	$14,310	$831,388	$33,256	$864,644	Continue Interim Re-clear
ASH	Gray's Branch	Gray's Branch	3000701	68.3	23.0	$14,310	$329,121	$13,165	$342,286	Continue Interim Re-clear
ASH	Olive Hill	Globe	3103101	150.3	75.0	$14,310	$1,073,221	$42,929	$1,116,149	Continue Interim Re-clear
ASH	Wurtland	Route 503	3110903	45.5	18.0	$14,310	$257,573	$10,303	$267,876	Start Interim Re-clear
ASH	47th Street	39th Street	3008002	12.9	12.9	$14,310	$184,594	$7,384	$191,978	Interim Re-clear
ASH	Bellfonte	Westwood	3000302	23.0	23.0	$14,310	$329,121	$13,165	$342,286	Interim Re-clear
	Ashland District (Task 2) Totals				**210.0**		**$3,005,017**	**$120,201**	**$3,125,218**	
HAZ	Combs	Combs	3301401	9.0	9.0	$7,093	$63,837	$2,553	$66,390	Interim Re-clear
HAZ	Combs	Airport Gardens	3301402	42.9	42.9	$7,093	$304,290	$12,172	$316,461	Interim Re-clear
HAZ	Beckham	Hindman	3308401	101.5	61.5	$7,093	$436,220	$17,449	$453,668	Start Interim Re-clear
HAZ	Stinnett	Redbird	3311101	120.7	84.2	$7,093	$597,231	$23,889	$621,120	Continue Interim Re-clear
HAZ	Stinnett	Beech Fork	3311102	9.5	1.5	$7,093	$10,640	$426	$11,065	Complete Interim Re-clear
HAZ	Bluegrass	Walkertown	3300601	29.0	12.7	$7,093	$90,081	$3,603	$93,684	Start Interim Re-clear
HAZ	Reedy	Deane	3311401	43.2	43.2	$7,093	$306,418	$12,257	$318,674	Interim Re-clear
	Hazard District (Task 2) Totals				**255.0**		**$1,808,715**	**$72,349**	**$1,881,064**	
PKV	Allen	Distribution	3400101	38.0	15.0	$14,832	$222,484	$8,899	$231,383	Continue Interim Re-Clear
PKV	Elwood	Dorton	3401001	46.0	46.0	$14,832	$682,283	$27,291	$709,575	Interim Re-clear
PKV	Elwood	Virgie	3401002	71.0	71.0	$14,832	$1,053,090	$42,124	$1,095,213	Complete Interim Re-clear
PKV	Fishtrap	Distribution	3414901	4.4	4.0	$14,832	$59,329	$2,373	$61,702	Interim Re-clear
PKV	Barrenshe	Vulcan	3200202	49.0	49.0	$14,832	$726,780	$29,071	$755,851	Interim Re-clear
PKV	Fords Branch	Shelby	3411901	39.0	39.0	$14,832	$578,458	$23,138	$601,596	Interim Re-clear
PKV	Fords Branch	Robinson Creek	3411902	56.0	15.0	$14,832	$222,484	$8,899	$231,383	Interim Re-clear
PKV	Burdine	Levisa	3409502	39.0	15.0	$14,832	$222,484	$8,899	$231,383	Start Interim Re-clear
PKV	Kenwood	Hagerhill	3409303	51.0	20.0	$14,832	$296,645	$11,866	$308,511	Start Interim Re-clear
PKV	Draffin	Yellowhill	3400702	12.4	12.0	$14,832	$177,987	$7,119	$185,106	Interim Re-clear
PKV	Lovely	Lovely	3202201	41.0	20.0	$14,832	$296,645	$11,866	$308,511	Start Interim Re-clear
	Pikeville District (Task 2) Totals				**306.0**		**$4,538,668**	**$181,547**	**$4,720,215**	
	INTERIM RE-CLEARING (TASK 2) TOTALS				**771**		**$9,352,400**	**$374,096**	**$9,726,496**	

KPSC Case No. 2014-00396
In Conformity with Paragraph 8(d)
Of the Settlement Agreement
Attachment 4
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Filed March 31, 2016

Kentucky Power Forestry Plan Terminology

Feeder Breaker Zone
Synonymous with Station Zone. Segment of line extending from the circuit station breaker to the first operating device. This zone includes unfused taps, but does not include fused taps.

Full Circuit Reclear
Entire circuit from the station breaker to the end of the circuit.

Recloser Zone
Line segment extending from a specific recloser to the next operating device. This zone includes unfused taps, but does not include fused taps.

Partial Reclear
A portion of the circuit is planned for reclearing.

BID JOB
Planned reclearing work released as an open, lump-sum bid for competing contractors.

Finish Full Circuit Reclear
Reclearing scheduled to complete Full Circuit Reclear that began in the previous year.

2nd Recloser Zone
Line segment beginning at the second operating device beyond the station circuit breaker extending to the next operating device. This zone includes unfused taps, but does not include fused taps.

Quality-of-Service Work
Tree trimming or removal work scheduled for a line segment to address reliability issues. This work does not conform to reclearing specifications (e.g.-Hotspotting).

Cycle Buster Tree
A tree that has to be revisited before the circuit is due for its next cycle trim.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Completed Task 2 work on Greysbranch - Greysbranch Circuit in Greenup County

2016 DISTRIBUTION VEGETATION MANAGEMENT

REPORT OF KENTUCKY POWER COMPANY

IN CONFORMITY WITH PARAGRAPH 8(d)

OF THE SETTLEMENT AGREEMENT,

APPENDIX A TO THE COMMISSION'S JUNE 22, 2015

ORDER IN CASE NO. 2014-00396

April 3, 2017

In accordance with the Public Service Commission's Order dated June 22, 2015 in Case No. 2014-00396, Kentucky Power provides the following report regarding its Vegetation Management Program for the 2016 calendar year:

INTRODUCTION

The Commission's June 22, 2015 Order in Case No. 2014-00396 approved, with certain modifications unrelated to this report, the Settlement Agreement among Kentucky Power Company, Kentucky Industrial Utility Customers, Inc., and the Kentucky School Boards Association ("Settlement Agreement"). Paragraph 8 of the Settlement Agreement modified the Company's existing Vegetation Management Program. As approved by the Commission the Vegetation Management Program:

- Extended the period to perform the initial re-clearing of the Company's distribution right-of-way through 2018 ("Task 1");
- Implemented an interim program for the re-clearing of those portions of the Company's distribution right-of-way that were initially re-cleared beginning July 2010 ("Task 2"). The Settlement Agreement projects Task 2 will be completed by June 30, 2019;
- Provided for the initiation of a five-year cycle for Vegetation Management Program maintenance re-clearing ("Task 3") beginning July 1, 2019;
- Maintained the Task 1 operation and maintenance ("O&M") approved by the Commission in Case No. 2009-00459;
- Provided an additional $10,655,900 in revenue to fund the Task 2-related O&M activities required under the Settlement Agreement.
- Provided modified total spending requirements for the years 2015-2023. These requirements will decrease beginning in 2019 with the completion of Task 1 and Task 2 and the initiation of Task 3;
- Provided an $11,780,408 reduction of annual base rates beginning July 1, 2019 for those customer classes funding the Vegetation Management Program;
- Established a one-way balancing account to track annual deviations from the $27,661,060 in total program expenditures included in annual base rates beginning July 1, 2015; and

- Required the Company to obtain Commission approval before deviating on either a Company or a district basis by more than 10% from the budgeted (September 30) expenditure levels.

2016 VEGETATION MANAGEMENT PLAN AND UPDATED FORECASTS

Kentucky Power filed its 2016 Vegetation Management Plan on September 29, 2015. The 2016 Vegetation Management Plan projected the Company would complete 986 miles of Task 1 work at a total O&M cost of $17,237,965 and capital funding of $1,195,108. The plan projected Kentucky Power would complete 771 miles of Task 2 work at an O&M cost of $10,423,095 and $327,217 in capital funding.[1]

In connection with its 2015 Vegetation Management Report, filed March 31, 2016, Kentucky Power updated its forecast of Task 1 work to be completed in 2016. Task 1 work was increased from 986 miles to 1,200 miles. Task 2 work remained unchanged at 771 miles.

The 2015 Report also indicated that total Task 1 and Task 2 O&M forecasted expenditures were projected to increase from $27,661,060 to $27,664,598. The 2015 Report indicated that Task 1 and Task 2 forestry capital funding would be increased to $2,089,725.[2]

AUTHORITY TO DEVIATE FROM 2016 VEGETATION MANAGEMENT PLAN

The Company on April 13, 2016 filed its application seeking leave to deviate by more than 10% from its 2016 budgeted expenditure levels for the Pikeville and Hazard districts.[3] In its request, the Company sought to increase the 2016 budgeted Pikeville district expenditures by 22.82% and to reduce the Hazard district's 2016 budgeted expenditures by 11.1%. The purpose of the deviations was to permit Kentucky Power to complete Task 1 work in each district at approximately the same time.

The Commission granted the Company's application by order entered August 11, 2016.

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[1] Task 1 and Task 2 total capital funding was $1,522,325.

[2] The total 2016 forestry capital budget for 2016, including projected forestry capital expenditures unrelated to Task 1 and Task 2 work, was $2,433,956.

[3] *In the Matter of: Application Of Kentucky Power Company For Authority To Deviate From The Ten Percent Limitation On Variations In Vegetation Management Expenditures*, Case No. 2016-00143.

2016 EXPENDITURES AND RIGHT-OF-WAY CLEARED

A. 2016 Distribution Vegetation Management Expenditures

Total 2016 O&M expenditures for the Vegetation Management program were $27,774,545. 2016 O&M total expenditures exceeded the 2016 Plan expenditure target, filed September 29, 2015, by $113,485 (0.41%), and the revised goal, filed March 31, 2016, by $109,947 (0.4%).

Actual 2016 Task 1 O&M expenditures were $17,492,806. The actual Task 1 O&M expenditures exceeded the September 29, 2015 forecast by $254,841 (1.48%).

2016 Task 2 O&M expenditures totaled $10,281,740 and were $144,893 (1.39%) below budget).

The Capital Plan for Task 1 and Task 2 as filed was $1,522,325. The actual 2016 forestry capital funding for Task 1 and Task 2 was $2,664,901. This exceeded the projected Capital Plan for Task 1 and Task 2 by $1,142,576 or 75%. Total forestry capital funding for calendar year 2016 was $3,718,526. All additional capital funds were used to remove trees larger than 18 inches in diameter, to widen rights-of-way, and for tree growth regulator applications (soil injections).

B. 2016 Vegetation Management Mileage Cleared

Kentucky Power's 2016 Plan, filed September 29, 2015, projected the completion of 986 miles of Task 1 work and 771 miles of Task 2 work during 2016. The plan also projected the Company would spray 2,500 acres to control vegetation. Spraying limits vegetation growth between trim cycles.

As part of its 2015 Vegetation Management Report filed March 31, 2016 Kentucky Power increased its projected 2016 Task 1work by 21.7% to 1,200 miles. Projected Task 2 work and spraying remained unchanged.

Table 1 below compares the 2016 work completed to the projections contained in its 2016 Plan and the March 31, 2016 update:

Table 1: 2016 Work Plan Comparison to Actual Plan Completion

Work	2016 Plan	March 31, 2016 Update	Work Completed in 2016	Difference between Actual vs 2016 Plan	Difference between Actual and March 31, 2016 Update
Task 1 Miles	986	1,200	1,094	108	-106
% Completed	-	-	-	111.0%	91.2%
Task 2 Miles	771	771	711	-60	-60
% Completed	-	-	-	92.2%	92.2%
Acres Sprayed	2,500	2,500	3,780	1,280	1,280
% Completed	-	-	-	151.2%	151.2%

Three factors contributed to the variations between revised projected miles cleared and actual miles cleared:

- Travel time for the crews shifted from the Hazard district to Pikeville district was greater than anticipated thereby reducing the amount of time crews were engaged in vegetation maintenance in the Pikeville district.

- The scope of Task 2 work was expanded to remove additional overhanging limbs. The additional work removed limbs from both within and outside of the right-of-way.

- Additional resources ($2,215,040 instead of the budgeted $1,200,000) were directed to spraying.

As of December 31, 2016 Kentucky Power completed approximately 83% of the Task 1 work since Task 1 work began in June 29, 2010. This compares to 70% of the Task 1 work completed as of December 31, 2015. Kentucky Power is on schedule to complete Task 1 work by December 31, 2018. At December 31, 2016, the Company was 108 miles ahead of the clearance pace required to complete the Task 1 work by December 31, 2018.

As of December 31, 2016 Kentucky Power had completed approximately 100% of the forecasted Task 2 work to date. This compares to 117% of the forecasted Task 2 work completed as of December 31, 2015. Kentucky Power is on schedule to complete Task 2 work by July 1, 2019.

Since the Company's Vegetation Management program began, Kentucky Power has trimmed 507,259 trees, cleared 14,847 acres of brush, sprayed 16,447 acres to control vegetation, and removed 1,508,893 trees.

C. 2016 Distribution Vegetation Management Work by District

Table 2 below compares the Company's 2016 District O&M expenditures to the projected expenditure levels approved by the Commission in its August 11, 2016 Order in Case No. 2016-00143 approving the Company's application for a deviation from the 2016 Plan filed September 29, 2015.

Table 2: 2016 District O&M Expenditures vs Projected Budgeted Expenditures

Nature of Expense	Ashland	Hazard	Pikeville	Kentucky Total
Task 1	$4,729,054.27	$2,994,719.02	$9,365,556.68	$17,089,329.96
Task 2	$4,139,229.85	$1,942,600.47	$3,897,308.96	$9,979,139.28
Internal Labor Task 1	$131,799.91	$133,355.52	$138,320.52	$403,475.95
Internal Labor Task 2	$89,872.45	$93,248.66	$119,479.18	$302,600.29
Total	**$9,089,956.48**	**$5,163,923.67**	**$13,520,665.34**	**$27,774,545.48**
Budget	$8,264,806.00	$5,268,130.00	$14,131,662.00	$27,664,598.00
% Spend per District	109.984%	98.022%	95.676%	100.397%

Table 3 below provides the 2016 Task 1 and Task 2 work performed by district and estimated work remaining.

Table 3: 2016 Actual District Mileage Performed and Remaining Initial Re-clear Mileage

Work Task	Ashland	Hazard	Pikeville	Kentucky Total
Task 1	306.4	204.9	583.0	1094.3
Task 2	229.0	202.4	280.0	711.4
Total Re-clear Miles	**535.4**	**407.3**	**863.0**	**1805.7**
Acres Sprayed	680.1	1174.6	1925.5	3780.2
Remaining Initial Re-clear Mileage	**631.0**	**329.2**	**499.8**	**1460.0**

Attachment 1 to this report details the Task 1 Vegetation Management work and expenditures by circuit. Attachment 2 similarly reports the 2016 Task 2 Vegetation Management work and expenditures by circuit. Both attachments provide the number of miles of circuit completed for each task, acres of brush cut, acres of brush sprayed, amount of tree growth regulator (soil injection) applied, number of trees removed, and number of trees trimmed.

Consistent with past filings, O&M and capital expenditures are not separately accounted for on a circuit-by-circuit basis. The costs in Attachment 1 (Task 1) and 2 (Task 2) represent the total O&M and Capital expenditures for each circuit. Also unallocated on a circuit-by-circuit basis are Internal Labor & Fleet, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditor expenses, tree contractor's field supervision, and incentive program for tree contractor's employees.

D. Measures Of Improvement In System Reliability (SAIFI, CAIDI, SAIDI, and CMI)

Table 4 provides total system reliability indices for Kentucky Power's distribution system from 2010 (when the Vegetation Management Program began) through December 31, 2016. Table 5 provides reliability indices limited to Tree Inside of Right-of-Way outages for the same period.

Table 4 and Table 5 include data relating to System Average Interruption Frequency Index ("SAIFI"), the Customer Average Interruption Duration Index ("CAIDI"), and the System Average Interruption Duration Index ("SAIDI") for each reporting period. Excluded from the calculation of the indices are major events as defined by IEEE standard 1366.

Table 4: Seven Year Reporting Indices for all Outage Cause Codes

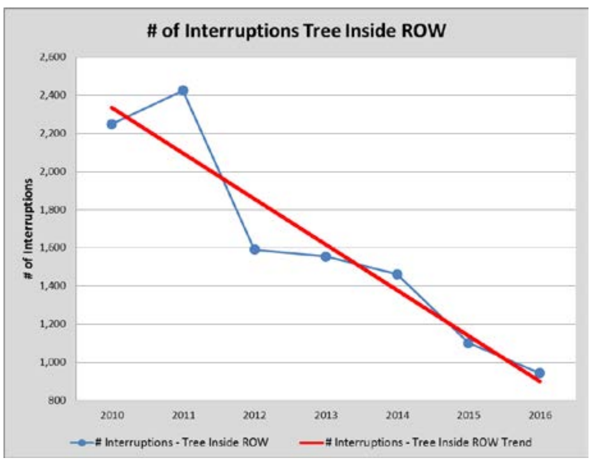
Year	SAIFI	CAIDI	SAIDI
2010	2.4701	169.39	418.4
2011	3.0854	195.38	602.84
2012	2.4174	189.46	457.99
2013	2.1442	178.49	382.71
2014	2.3736	212.88	505.29
2015	2.4669	189.76	468.12
2016	2.1753	205.14	446.24

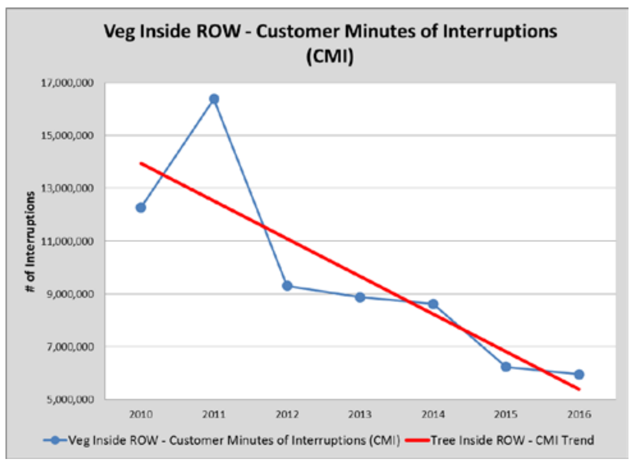
Table 5: Seven Year Reporting Indices for Tree Inside Right-of-Way Outage Cause Codes

YEAR	Tree Inside Right-of-Way SAIFI	Tree Inside Right-of-Way CAIDI	Tree Inside Right-of-Way SAIDI
2010	0.3707	190.7	70.68
2011	0.4192	227.4	95.32
2012	0.2562	258.8	66.31
2013	0.2815	184.3	51.88
2014	0.2154	236.3	50.89
2015	0.1782	207.6	37
2016	0.1719	207.2	35.61

Table 5 highlights the efficacy of the Company's Vegetation Management Program, which focuses on inside right-of-way vegetation management. The 2016 Tree Inside Right-Of-Way SAIFI, CAIDI, and SAIDI metrics are 40%, 5%, and 43%, respectively, below the average Tree Inside Right-Of-Way SAIFI, CAIDI, and SAIDI metrics for the period 2010-2015.

Since the Vegetation Management Program began in July 2010, the annual number of Tree Inside Right-Of-Way outages (excluding major event days) has been reduced by approximately 58% from 2,250 to 943. The annual number of customer minutes of interruption associated with these events has been reduced by approximately 52% from 12,280,664 to 5,949,862.





E. <u>Vegetation Management Program-To-Date Expenditures</u>

Kentucky Power committed to expend $127,563,218 on Vegetation Management O&M from the beginning of the program June 29, 2010 through December 31, 2016. In that period the Company expended $129,117,176 or $1,553,958 (1.2%) more than its commitment. Kentucky Power's Vegetation Management Program forecasted capital spending ("Planned Dollars") during the same period was $15,222,325. Through that period the Company expended $21,385,680 or $6,163,355 (40.5%) more than planned. Table 6 below provides the annual Committed Dollars, Actual Dollars, and Variance for both O&M and Capital Expenditures.

Table 6: Vegetation Management Program Year to Date Expenditures						
Year	O&M Vegetation Management Program			Capital Vegetation Management Program		
	Planned Dollars	Actual Dollars	Variance	Planned Dollars	Actual Dollars	Variance
2010	$8,618,983	$8,950,346	$331,363	$1,000,000	$520,507	-$479,493
2011	$17,237,965	$17,261,128	$23,163	$2,500,000	$1,473,700	-$1,026,300
2012	$17,237,965	$17,029,248	-$208,717	$2,550,000	$2,643,820	$93,820
2013	$17,237,965	$17,466,579	$228,614	$2,550,000	$3,428,239	$878,239
2014	$17,237,965	$17,567,439	$329,474	$2,550,000	$3,901,140	$1,351,140
2015	$22,327,777	$23,067,891	$740,114	$2,550,000	$5,699,748	$3,149,748
2016	$27,664,598	$27,774,545	$109,947	$1,522,325	$3,718,526	$2,196,201
Total	**$127,563,218**	**$129,117,176**	**$1,553,958**	**$15,222,325**	**$21,385,680**	**$6,163,355**

F. <u>Balancing Account</u>

Under paragraph 8(e)(ii) of the Settlement Agreement, a one-way balancing account was established beginning July 1, 2015. The account, which reflects the Company's commitment to make $27,661,060 in Vegetation Management O&M expenditures during each July 1 through June 30 period ("Vegetation Management Year"), will continue until base rates are next established. The balancing account will track any shortfall or over-expenditure in Vegetation Management Year Vegetation Management O&M expenditures.

When Company base rates are established after July 1, 2019 any cumulative shortfall in Vegetation Management O&M expenditures will be refunded to customers or used to reduce the Company's revenue requirement. The Company may not recover any cumulative over-expenditure.

Further information concerning the Balancing Account is presented in Table 7.

Table 7: Kentucky Power Budgeted Expenses for Case No. 2014-00396							
Targeted Task VM Program	Year				Total Budget	Total Actual	Variance
	Budget 2015 (6 Months)	Actual 2015	Budget 2016	Actual 2016			
Task 1	$8,618,983	$9,485,769	$17,237,965	$17,492,806	$25,856,948	$26,978,575	$1,121,627
Task 2	$5,089,812	$4,134,948	$10,426,633	$10,281,740	$15,516,445	$14,416,688	-$1,099,757
VM Program Dollars	$13,708,795	$13,620,717	$27,664,598	$27,774,546	$41,373,393	$41,395,263	$21,870

The Company's Vegetation Management O&M expenditures since the enhanced plan was approved in Case No. 2014-00396 were $41,395,263. These expenditures represent 100.05% of the requirement or $21,870 (0.05%) more than its commitment. Kentucky Power continues to track/monitor the Vegetation Management total O&M expenditures.

KPSC Case No. 2014-00396
In Conformity with Paragraph 8(d)
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Filed April 3, 2017
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2016 KY POWER FORESTRY CIRCUIT HISTORY

Task 1 - Ashland District

Circuit data in BOLD represent Full-Circuit Reclearing

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditors expense, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
2206403	**South Neal - Whites Creek**	**$1,346,633.48**	**38.8**	**18.8**	**18.8**	**8,969**	**12,680**	**97.7**	**119.3**		**Completed Full Circuit Clearing**
3000101	**Ashland - 25th St**	**$6,360.32**	**1.4**	**1.4**	**1.4**	**22**	**11**	**0.0**	**0.0**		**Completed Full Circuit Clearing**
3000102	**Ashland - 29th St**	**$92,659.82**	**7.0**	**7.0**	**7.0**	**142**	**432**	**1.3**	**0.0**		**Completed Full Circuit Clearing**
3000103	**Ashland - 14th St**	**$12,123.09**	**1.3**	**1.3**	**1.3**	**17**	**3**	**0.0**	**0.0**		**Completed Full Circuit Clearing**
3000104	**Ashland - 3rd St**	**$369.97**	**0.2**	**0.2**	**0.2**	**0**	**0**	**0.0**	**0.0**		**Completed Full Circuit Clearing**
3000105	**Ashland - 1st St**	**$2,192.55**	**1.7**	**1.7**	**1.7**	**0**	**0**	**0.1**	**0.0**		**Completed Full Circuit Clearing**
3001003	**Hitchens - Grayson**	**$540,538.21**	**48.4**	**21.6**	**22.8**	**1,614**	**3,318**	**16.4**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3001102	**Hoods Creek - Rural**	**$434,306.69**	**47.0**	**32.2**	**19.8**	**1,403**	**4,081**	**9.3**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3001204	**Howard Collins - Summit**	**$259,351.62**	**25.7**	**25.7**	**11.0**	**1,125**	**4,588**	**15.0**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3003701	**Coalton - U.S. 60 W**	**$114,869.16**	**87.5**	**5.0**	**5.0**	**244**	**427**	**2.2**	**107.3**		**Completed Full Circuit Clearing**
3007905	**Busseyville - Mattie**	**$1,094,582.88**	**91.0**	**69.5**	**60.0**	**3,922**	**12,796**	**117.1**	**0.0**		**Continued Full Circuit Clearing - To complete in 2017**
3010602	**Russell - Bear Run**	**$171,680.82**	**13.0**	**10.0**	**13.0**	**567**	**2,150**	**4.2**	**3.4**		**Completed Full Circuit Clearing**
3116101	**Grayson - Lansdowne**	**$430,288.68**	**36.1**	**36.1**	**36.1**	**2,062**	**2,786**	**19.1**	**11.4**		**Completed Full Circuit Clearing**
3116102	**Grayson - Dixie Park**	**$113,253.22**	**33.5**	**12.9**	**33.5**	**400**	**664**	**3.6**	**0.8**		**Completed Full Circuit Clearing**
3116701	**Belhaven - Diedrich**	**$232,935.40**	**12.1**	**12.1**	**12.1**	**765**	**1,245**	**1.5**	**0.0**		**Completed Full Circuit Clearing**
3116702	**Belhaven - Indian Run**	**$367,587.50**	**19.5**	**19.5**	**19.3**	**1,268**	**1,772**	**8.6**	**2.6**		**Began Full Circuit Clearing - To be completed in 2017**
3116703	**Belhaven - Argillite**	**$218,942.65**	**28.0**	**28.0**	**13.0**	**454**	**565**	**0.5**	**1.6**		**Completed Full Circuit Clearing**
3117601	**Princess - Meade**	**$179,205.48**	**46.8**	**12.6**	**12.6**	**780**	**1,062**	**5.2**	**76.9**		**Completed Full Circuit Clearing**
3117602	**Princess - Rt 180**	**$483,618.89**	**25.0**	**25.0**	**25.0**	**1,406**	**6,112**	**27.0**	**55.9**		**Completed Full Circuit Clearing**
3000202	Big Sandy - Burnaugh	$56,673.65	84.5	0.0	0.0	0	0	0.0	100.9		Ground Spray
3000302	Bellefonte - Flatwoods	$2,025.12	3.2	0.0	0.0	0	0	0.0	4.9		Ground Spray
3000303	Bellefonte - Bellefonte	$17,501.11	56.2	0.0	0.0	2	3	0.0	0.0		Quality of Service Work
3000304	Bellefonte - Town Center	$1,348.78	2.7	0.0	0.0	0	0	0.0	4.2		Ground Spray
3000601	Grahn - Distribution	$1,499.03	45.3	0.0	0.0	0	1	0.0	0.0		Quality of Service Work
3000901	Highland - Russell	$8,599.27	24.0	0.0	0.0	5	0	0.0	13.5		Ground Spray
3000903	Highland - Wurtland	$1,773.77	15.0	0.0	0.0	0	0	0.0	3.4		Ground Spray
3001001	Hitchins - Damron Branch	$25,573.67	46.2	0.0	0.0	63	486	1.8	0.0		Widening
3001002	Hitchins - Willard	$4,742.98	152.0	0.0	0.0	7	10	0.1	0.0		Quality of Service Work
3001004	Hitchins - EK Road	$3,786.60	31.4	0.0	0.0	0	0	0.0	0.0		Work Planning for 2017
3001101	Hoodscreek - Summitt	$2,223.72	22.7	0.0	0.0	1	11	0.0	0.0		Quality of Service Work
3001201	Howard Collins - 13th St.	$1,073.36	13.2	0.0	0.0	0	0	0.0	3.1		Ground Spray
3001203	Howard Collins - Floyd St.	$1,149.67	11.0	0.0	0.0	0	0	0.0	1.9		Ground Spray
3001204	Howard Collins - Summitt	$34,894.68	25.7	0.0	0.0	1	142	0.0	0.0		Widening
3001402	Louisa - High Bottom	$430.51	13.0	0.0	0.0	0	0	0.0	1.1		Ground Spray
3002001	South Shore - Siloam	$3,081.55	34.4	0.0	0.0	0	5	0.0	0.0		Quality of Service Work
3002002	South Shore - Distribution	$530.08	8.8	0.0	0.0	0	0	0.0	0.9		Ground Spray
3003702	Coalton - Cannonsburg	$67,359.89	23.3	0.0	0.0	0	1670	0.0	18.4		Widening and Ground Spray
3003703	Coalton - Trace Creek	$58,351.96	82.5	27.7	0.0	24	1,272	0.0	0.0		Began Planning and Widening - To Complete in 2017
3007903	Busseyville - Louisa	$29,757.98	44.0	44.0	0.0	0	23	0.4	0.0		Began Planning and Widening - To Complete in 2017
3007904	Busseyville - Torchlight	$15,902.53	97.0	0.0	0.0	31	189	0.3	0.0		Widening
3008003	47th Street - Catlettsburg	$12,838.30	28.0	0.0	0.0	0	0	0.0	24.9		Ground Spray
3008701	Cannonsburg - Cannonsburg	$1,226.79	63.0	0.0	0.0	0	3	0.0	0.0		Quality of Service Work
3008702	Cannonsburg - Rt. 3	$4,799.19	100.0	0.0	0.0	0	7	0.0	0.0		Quality of Service Work
	ASHLAND DISTRICT Totals	**$6,458,644.62**		**412.3**	**313.6**	**25,294**	**58,514**	**331.4**	**556.1**	**0.0**	

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2016 KY POWER FORESTRY CIRCUIT HISTORY

Task 1 - Hazard District

Circuit data in BOLD represent Full-Circuit Reclearing

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditors expense, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
3300601	**Bluegrass - Walkertown**	**$210,294.94**	**29.0**	**15.8**	**15.8**	**1,060**	**3,613**	**19.0**	**18.1**		**Completed Full Circuit Clearing**
3301101	**Chavies - Chavies**	**$37,421.73**	**69.1**	**2.5**	**0.3**	**8**	**135**	**3.5**	**58.7**		**Began Full Circuit Clearing - To be completed in 2017**
3309302	**Vicco - Jeff**	**$270,264.34**	**84.7**	**29.8**	**24.9**	**825**	**5,138**	**31.8**	**98.2**		**Continued Full Circuit Clearing - To complete in 2017**
3309901	**Slemp - Defeated Creek**	**$84,407.72**	**13.4**	**13.4**	**13.4**	**64**	**4,032**	**70.9**	**4.7**		**Completed Full Circuit Clearing**
3309902	**Slemp - Leatherwood**	**$497,953.27**	**71.3**	**27.7**	**27.7**	**1,072**	**17,383**	**76.9**	**10.2**		**Continued Full Circuit Clearing - To complete in 2017**
3310501	**Haddix - Quicksand**	**$44,137.81**	**201.0**	**10.0**	**0.0**	**0**	**4**	**0.0**	**84.1**		**Ground Spray**
3310502	**Haddix - Canoe**	**$436,296.92**	**125.0**	**42.3**	**43.3**	**1,136**	**7,206**	**97.4**	**72.4**		**Continued Full Circuit Clearing - To complete in 2017**
3401301	**Fleming - Neon**	**$359,870.24**	**20.5**	**20.5**	**20.5**	**1,725**	**2,678**	**28.4**	**0.0**		**Completed Full Circuit Clearing**
3401302	**Fleming - McRoberts**	**$191,266.04**	**30.3**	**20.3**	**20.3**	**820**	**1,130**	**22.5**	**0.0**		**Completed Full Circuit Clearing**
3420001	**Softshell - Vest**	**$267,953.87**	**56.7**	**38.7**	**38.7**	**957**	**8,662**	**72.3**	**0.0**		**Completed Full Circuit Clearing**
3300602	Bluegrass - Hazard	$10,195.55	0.0	0.0	0.0	0	0	0.0	19.2		Ground Spray
3303901	Leslie - Hyden	$150,790.27	0.0	0.0	0.0	0	0	0.0	360.0		Ground Spray
3303902	Leslie - Wooton	$10,494.56	0.0	0.0	0.0	10	132	0.3	9.8		Ground Spray and Widening
3303903	Leslie - Hals Fork	$4,611.39	0.0	0.0	0.0	0	0	0.0	5.7		Ground Spray
3307301	Bulan - Ary Hiner	$2,922.87	0.0	0.0	0.0	5	64	0.8	0.0		Quality of Service Work
3307302	Bulan - Ajax Dwarf	$3,820.56	40.0	0.0	0.0	0	18	0.0	0.0		Quality of Service Work
3308002	Jackson - Panbowl	$5,569.11	31.6	0.0	0.0	0	0	0.0	8.3		Ground Spray
3308601	Collier - Upper Rockhouse	$40,510.96	0.0	0.0	0.0	0	0	0.0	86.9		Ground Spray
3308603	Collier - Smoot Creek	$988.97	0.0	0.0	0.0	16	0	0.0	0.0		Quality of Service Work
3309001	Jeff - Boone Ledge	$3,203.36	5.0	0.0	0.0	0	4	0.0	3.8		Ground Spray
3309002	Jeff - Jeff	$18,418.15	5.7	0.0	0.0	0	0	0.0	14.3		Ground Spray
3309003	Jeff - Viper	$2,459.61	0.0	0.0	0.0	0	0	0.0	6.1		Ground Spray
3309101	Whitesburg - Whitesburg	$2,549.93	10.0	0.0	0.0	0	1	0.0	0.0		Quality of Service Work
3309103	Whitesburg - Cowan	$23,419.93	0.0	0.0	0.0	0	0	0.0	38.2		Ground Spray
3309104	Whitesburg - Crafts Colley	$14,753.48	28.0	0.0	0.0	8	138	0.0	0.0		Widening
3309301	Vicco - Red Fox	$41,151.13	0.0	0.0	0.0	0	0	0.0	94.5		Ground Spray
3310501	Haddix - Quicksand	$44,137.81	201.1	10.0	0.0	0	4	0.0	84.1		Gound Spray
3312202	Engle - Grapevine	$9,699.80	0.0	0.0	0.0	0	0	0.0	31.9		Ground Spray
3420002	Softshell - Leburn	$29,704.41	0.0	0.0	0.0	17	189	0.4	65.6		Ground Spray and Widening
3451202	Beefhide - Dunham	$524.59	9.8	0.0	0.0	0	6	0.0	0.0		Quality of Service Work
	HAZARD DISTRICT Totals	**$2,819,793.32**		**231.0**	**204.9**	**7,723**	**50,537**	**424.2**	**1,174.8**	**0.0**	

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2016 KY POWER FORESTRY CIRCUIT HISTORY

Task 1 - Pikeville District

Circuit data in BOLD represent Full-Circuit Reclearing

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditors expense, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
3201002	**Tom Watkins - Distribution - A**	**$610,901.93**	**28.8**	**0.0**	**23.0**	**2356**	**11943**	**39.6**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3400302	**Betsy Layne - Tram**	**$577,639.76**	**35.0**	**35.0**	**35.0**	**1896**	**6563**	**47.8**	**9.3**		**Completed Full Circuit Clearing**
3401702	**Henry Clay - Regina**	**$857,818.74**	**112.6**	**49.3**	**25.5**	**1352**	**7616**	**251.2**	**14.1**		**Began Full Circuit Clearing - To be completed in 2017**
3401703	**Henry Clay - Ashcamp**	**$930,119.06**	**43.0**	**43.0**	**43.0**	**2373**	**10359**	**106.1**	**0.0**		**Completed Full Circuit Clearing**
3401801	**Index - Distribution**	**$561,216.52**	**54.1**	**54.0**	**52.8**	**2067**	**8971**	**95.5**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3402204	**McKinney - Maytown**	**$472,134.31**	**36.0**	**36.0**	**36.0**	**1668**	**9871**	**54.9**	**0.0**		**Completed Full Circuit Clearing**
3402501	**Middle Creek - Distribution**	**$51,894.38**	**6.0**	**6.0**	**6.0**	**148**	**1099**	**13.3**	**0.0**		**Completed Full Circuit Clearing**
3403001	**Pikeville - City**	**$121,472.50**	**20.0**	**12.9**	**12.9**	**373**	**1488**	**15.0**	**0.0**		**Completed Full Circuit Clearing from 2015**
3403301	**Prestonsburg - City**	**$53,235.96**	**6.7**	**7.0**	**7.0**	**157**	**796**	**3.7**	**0.0**		**Completed Full Circuit Clearing**
3407101	**Topmost - Dema**	**$328,934.89**	**37.0**	**37.0**	**37.0**	**1456**	**9043**	**70.3**	**0.6**		**Completed Full Circuit Clearing**
3407102	**Topmost - Caney**	**$10,239.14**	**4.4**	**4.4**	**2.5**	**31**	**660**	**9.1**	**0.0**		**Completed Full Circuit Clearing**
3407103	**Topmost - Kite**	**$290,475.29**	**25.4**	**25.0**	**25.0**	**1051**	**4392**	**48.2**	**0.0**		**Completed Full Circuit Clearing**
3409301	**Kenwood - W Van Lear**	**$212,589.61**	**19.0**	**19.0**	**19.0**	**637**	**3020**	**97.0**	**8.8**		**Completed Full Circuit Clearing**
3409302	**Kenwood - Auxier**	**$992.87**	**41.6**	**2.6**	**0.0**	**0**	**2**	**0.0**	**0.0**		**Capital Work**
3410501	**So. Pikeville - Pikeville**	**$20,486.44**	**10.0**	**10.0**	**1.3**	**26**	**179**	**0.6**	**0.0**		**Began Full Circuit Clearing - To be completed in 2017**
3410601	**E. Prestonsburg - Prestonsburg**	**$101,989.63**	**7.1**	**7.0**	**7.0**	**181**	**730**	**3.4**	**0.3**		**Completed Full Circuit Clearing**
3411401	**Dewey - Inez-A**	**$2,185,874.74**	**171.0**	**143.5**	**143.5**	**7272**	**28836**	**338.4**	**0.0**		**Completed Full Circuit Clearing from 2015**
3411802	**Johns Creek - Raccoon**	**$887,921.42**	**84.8**	**58.3**	**58.3**	**2372**	**11108**	**93.9**	**2.7**		**Completed Full Circuit Clearing from 2015**
3413402	**Garrett - Lackey**	**$335,802.34**	**34.7**	**35.0**	**25.6**	**1501**	**7276**	**56.2**	**0.0**		**Began Full Circuit Clearing**
3414501	**Consol - Coal Co**	**$13,420.49**	**4.6**	**0.0**	**3.6**	**13**	**293**	**3.0**	**0.0**		**Began Full Circuit Clearing**
3420103	**Mayo Trail - Davis Branch**	**$170,275.27**	**33.1**	**0.0**	**19.0**	**512**	**2388**	**34.1**	**0.0**		**Began Full Circuit Clearing**
3150501	Borderland - Nolan - A	$31,842.68	18.0	0.0	0.0	0	0	0.0	52.2		Ground Spray
3200201	Barrenshe - Freeburn	$30,284.52	13.0	0.0	0.0	52	197	4.6	0.0		Capital Work
3200204	Barrenshe - Pounding Mill	$39,290.78	16.0	0.0	0.0	0	0	3.9	64.1		Ground Spray
3202202	Lovely - Wolf Creek	$70,168.78	58.7	0.0	0.0	0	0	0.0	71.1		Ground Spray
3400301	Betsy Layne - Mud Creek	$652.39	77.0	0.0	0.0	0	1	0.0	0.0		Capital Work
3400701	Draffin - Belcher	$35,010.30	21.0	0.0	0.0	0	0	0.0	44.0		Ground Spray
3400901	Elkhorn City - City	$49,469.37	27.8	0.0	0.0	0	0	0.0	61.7		Ground Spray
3400902	Elkhorn City - Grassy	$3,807.46	4.0	0.0	0.0	0	0	0.0	4.0		Ground Spray
3401101	Falcon - Oil Springs	$4,542.70	48.5	0.0	0.0	0	2	0.0	15.5		Ground Spray and Capital
3401102	Falcon - Salyersville	$5,363.78	44.0	0.0	0.0	0	0	0.0	16.2		Ground Spray
3401103	Falcon - Burning Fork	$51,671.05	71.7	0.0	0.0	0	0	0.0	185.7		Ground Spray
3402002	Keyser - Stonecoal	$1,251.01	37.3	0.0	0.0	0	11	0.0	0.0		Capital Work
3402003	Keyser - Mullins	$54,532.78	29.6	0.0	0.0	0	0	0.0	60.3		Ground Spray
3403003	Pikeville - Cedar Creek	$8,535.26	28.0	0.0	0.0	6	9	0.0	0.0		Quality of Service Work
3403201	Beaver Creek - Ligon	$362.98	80.0	0.0	0.0	1	0	0.0	0.0		Quality of Service Work
3403202	Beaver Creek - Price	$13,119.97	21.0	0.0	0.0	0	0	0.0	13.2		Ground Spray
3403302	Prestonsburg - University	$2,162.36	18.0	0.0	0.0	0	50	0.1	0.0		Capital Work
3404301	Sidney - Big Creek	$13,126.62	29.1	0.0	0.0	0	0	0.0	0.0		Work Planning for 2017 Clearing
3408103	Salisbury - Martin	$8,620.02	46.0	0.0	0.0	1	15	0.0	0.0		Capital Work
3408303	Coleman - Peter Creek	$93,052.27	40.0	0.0	0.0	0	0	0.0	132.9		Ground Spray
3408304	Coleman - Calloway	$57,634.20	36.0	0.0	0.0	7	63	0.0	102.0		Capital Work and Ground Spray
3409002	W. Paintsville - Staffordsville	$5,338.50	21.0	0.0	0.0	3	3	0.0	0.0		Quality of Service Work
3411801	Johns Creek - Meta	$358,729.30	167.0	0.0	0.0	6	32	0.1	525.8		Capital Work and Ground Spray
3413401	Garrett - Garrett	$3,801.35	38.4	0.0	0.0	0	3	0.0	0.0		Capital Work
3417602	New Camp - Arh- W Wmsn	$13,490.19	17.0	0.0	0.0	0	0	0.0	0.0		Work Planning for 2017 Clearing
	PIKEVILLE DISTRICT Totals	**$9,751,295.91**		**585.0**	**583.0**	**27,518**	**127,019**	**1,389.9**	**1,384.5**	**0.0**	

KPSC Case No. 2014-00396
In Conformity with Paragraph 8(d)
Of the Settlement Agreement
Filed April 3, 2017
Attachment 2

2016 KY POWER FORESTRY CIRCUIT HISTORY
Ashland District - Task 2

Costs that were not allocated to a circuit include; internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditors expense, tree contractors' field supervision, and incentive program for tree contractor's employees.

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
3000201	Big Sandy - Fallsburg	$1,141,390.01	161.1	58.1	74.8	5,843	3,900	197.1	42.5		Begin 2nd Cycle Re-clearing - To be Completed in 2017
3000301	Bellefonte - Westwood	$438,318.48	23.5	23.5	23.5	2,133	498	44.1	0.0		Completed 2nd Cycle Re-clearing
3000701	Graysbranch - Graysbranch	$590,930.21	68.8	23.0	24.7	3,534	1,625	32.7	0.0		Begin 2nd Cycle Re-clearing - To be Completed in 2017
3001202	Howard Collins - 29th St.	$10,647.13	13.4	0.0	0.0	0	4	0.0	0.5		Work Planning for 2017
3008002	47th Street - 39th Street	$192,167.38	13.1	13.1	13.1	1,016	225	5.6	0.0		Completed 2nd Cycle Re-clearing
3103101	Olive Hill - Globe	$1,568,395.83	120.7	75.0	75.6	9,366	8,975	539.4	119.5		Begin 2nd Cycle Re-clearing - To be Completed in 2017
3110903	Wurtland - Rt. 503	$325,933.26	46.0	18.0	18.0	1,782	360	13.6	0.0		Begin 2nd Cycle Re-clearing - To be Completed in 2017
	ASHLAND DISTRICT Totals	**$4,267,782.30**		**210.7**	**229.7**	**23,674**	**15,587**	**832.5**	**162.5**	**0**	

Hazard District - Task 2

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
3300601	Bluegrass - Walkertown	$102,836.75	29.0	12.7	12.7	719	957	13.80	4.80		Completed 2nd Cycle Re-clearing
3301101	Chavies - Chavies	$153,764.99	69.1	17.5	10.0	183	3,788	59.90	0.00		Began 2nd Cycle Re-clearing - To be Completed in 2017
3301401	Combs - Combs	$54,202.85	9.0	9.0	9.0	235	665	9.30	0.00		Completed 2nd Cycle Re-clearing
3301402	Combs - Airport Gardens	$444,312.65	43.0	43.0	39.0	1,758	5,520	71.3	1.3		Began 2nd Cycle Re-clearing - To be Completed in 2017
3302701	Hazard - Black Gold	$8,654.78	55.0	0.0	0.0	0	0	0.0	7.9		2nd Cycle Ground Spray
3302703	Hazard - Hazard	$11,711.30	11.2	0.0	0.0	0	0	0.0	12.2		2nd Cycle Ground Spray
3307303	Bulan - Lotts Creek	$1,230.57	2.2	0.0	0.0	0	0	0.0	4.4		2nd Cycle Ground Spray
3308401	Beckham - Hindman	$314,752.16	102.0	44.0	23.5	603	4,556	45.3	1.8		Began 2nd Cycle Re-clearing - To be Completed in 2017
3308402	Beckham - Carr Creek	$3,060.90	111.0	0.0	0.0	0	4	0.0	0.0		Quality of Service Work
3308503	Bonnyman - Big Creek	$18,003.39	84.0	0.0	0.0	0	10	0.0	17.5		2nd Cycle Ground Spray
3309101	Whitesburg - Whitesburg	$4,441.02	10.0	0.0	0.0	2	5	0.4	0.0		Quality of Service Work
3309903	Slemp - Beech Fork	$4,052.40	0.0	0.0	0.0	0	324	8.5	0.0		2nd Cycle Widening
3311101	Stinnett - Redbird	$673,307.36	121.0	84.2	75.0	3,121	9,622	134.5	5.4		Began 2nd Cycle Re-clearing - To be Completed in 2017
3311102	Stinnett - Beech Fork	$21,866.59	10.0	1.5	1.5	28	399	0.3	0.0		Completed 2nd Cycle Re-clearing
3311103	Stinnett - Wendover	$1,399.71	0.0	0.0	0.0	0	0	0.0	1.0		2nd Cycle Ground Spray
3311401	Reedy - Deane	$304,834.73	44.5	44.5	31.7	1,100	4,173	54.2	0.0		Began 2nd Cycle Re-clearing - To be Completed in 2017
3314401	Mayking - Ermine	$17,178.15	28.8	0.0	0.0	0	57	0.1	27.4		2nd Cycle Ground Spray and Widening
3314402	Mayking - Millstone	$38,259.75	55.0	0.0	0.0	14	76	0.7	42.7		2nd Cycle Ground Spray and Widening
	HAZARD DISTRICT Totals	**$2,177,870.05**		**256.4**	**202.4**	**7,763**	**30,156**	**398.3**	**126.4**	**0**	

Pikeville District - Task 2

Circuit Number	Circuit Name	Cost (includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Tree Trim	Tree Removal	Brush Cut (acres)	Brush Spray (acres)	Tree Growth Regulator	COMMENTS
3200202	Barrenshe - Vulcan A	$764,268.07	49.0	49.0	49.0	2,928	10,581	69.9	0.0		Completed 2nd Cycle Re-clearing
3202201	Lovely - Lovely	$1,415,941.45	41.0	20.0	41.0	625	875	22.6	66.9		Completed 2nd Cycle Re-clearing and Ground Spray
3400101	Allen - Distribution	$180,725.87	26.0	15.0	26.0	555	1,913	38.9	55.6		Completed 2nd Cycle Re-clearing and Ground Spray
3400702	Draffin - Yellow Hill	$41,358.51	12.4	12.0	0.0	0	87	0.0	22.0		Widening and Ground Spray for 2nd Cycle Re-clearing
3401001	Elwood - Dorton	$394,289.44	43.3	43.3	35.0	1,270	8,632	49.2	12.8		Began Interim Re-Clearing - To be Completed in 2017
3401002	Elwood - Virgie	$1,310,942.11	71.0	71.0	80.0	4,795	22,932	123.1	6.7		Completed 2nd Cycle Re-Clearing
3404302	Sidney - Coburn Mtn.	$93,024.24	46.1	0.0	0.0	0	0	0.0	184.4		2nd Cycle Ground Spray
3409303	Kenwood - Hagerhill	$932,713.58	51.0	20.0	49.0	4,172	4,102	6.5	0.0		Began Interim Re-Clearing - To be Completed in 2017
3409502	Burdine - Levisa	$97,374.53	39.4	15.0	0.0	0	32	0.0	125.3		2nd Cycle Ground Spray and Widening
3411901	Fords Branch - Shelby	$12,853.46	42.4	39.0	0.0	0	0	0.0	0.0		Work Planning for 2017 2nd Cycle Re-clearing
3411902	Fords Branch - Robinson Ck	$40,243.55	39.4	15.0	0.0	0	0	0.0	39.4		2nd Cycle Ground Spray
	PIKEVILLE DISTRICT Totals	**$5,283,734.81**		**299.3**	**280.0**	**14,345**	**49,154**	**310.2**	**513.1**	**0**	

KY POWER Totals	**$11,729,387.16**		**766.4**	**712.1**	**45,782**	**94,897**	**1,541.0**	**802.0**	**0.0**

Kentucky Power Forestry Plan Terminology

Feeder Breaker Zone
Synonymous with Station Zone. Segment of line extending from the circuit station breaker to the first operating device. This zone includes unfused taps, but does not include fused taps.

Full Circuit Reclear
Entire circuit from the station breaker to the end of the circuit.

Recloser Zone
Line segment extending from a specific recloser to the next operating device. This zone includes unfused taps, but does not include fused taps.

Partial Reclear
A portion of the circuit is planned for reclearing.

BID JOB
Planned reclearing work released as an open, lump-sum bid for competing contractors.

Finish Full Circuit Reclear
Reclearing scheduled to complete Full Circuit Reclear that began in the previous year.

2nd Recloser Zone
Line segment beginning at the second operating device beyond the station circuit breaker extending to the next operating device. This zone includes unfused taps, but does not include fused taps.

Quality-of-Service Work
Tree trimming or removal work scheduled for a line segment to address reliability issues. This work does not conform to reclearing specifications (e.g.-Hotspotting).

Cycle Buster Tree
A tree that has to be revisited before the circuit is due for its next cycle trim.

EXHIBIT EGP - 5 COMPARISON OF FIVE-YEAR CYCLE AND SIX-YEAR CYCLE PROPOSALS

Year	Exhibit 9, (Case No. 2014-00396) 5 Year Cycle	Recommend Proposal (Case No. 2017-00179) 5 Year Cycle	Alternative Considered (Case No. 2017-00179) 6 Year Cycle
2015	$22,327,777	$23,067,891	$23,067,891
2016	$27,664,598	$27,774,546	$27,774,546
2017	$27,661,949	$27,661,060	$27,661,060
2018	$27,664,089	$21,638,766	$19,573,483
2019	$21,534,740	$21,283,946	$19,612,727
2020	$16,039,443	$21,472,777	$19,783,616
2021	$15,879,048	$21,688,685	$19,969,976
2022	$15,720,258	$21,881,312	$20,158,199
2023	$15,563,055	$22,101,559	$20,348,304
2024			$20,540,311
TOTAL	**$190,054,957**	**$208,570,541**	**$218,490,113**
3 year Average (2018, 2019, 2020)	**$21,746,090**	**$21,465,163**	**$19,656,609**
Cost for Cycle after 2018	**$15,880,652**	**$21,685,656**	**$20,068,855**
Avg Yrs Growth for Cycle	**-**	**4.94**	**5.65**