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1. Introduction

This report has been prepared by a subcommittee of independent directors of the Policy Committee of the American Electric Power Company Board of Directors. This document serves to “assess the actions the company is taking to mitigate the economic impact on our company of increasing regulatory requirements, competitive pressures, and public expectations to significantly reduce carbon dioxide and other emissions.” Several owners of AEP common stock proposed to seek shareholder approval of this assessment at the 2004 AEP annual meeting. The company and its Board of Directors concluded that the request was reasonable and agreed to conduct this study. As a result of this commitment, the resolution was withdrawn. Annex A contains the correspondence that documents this agreement between the company and the proponents of the shareholder resolution.

In the course of our evaluation, the subcommittee met with twenty-eight individuals having a diversity of views and expertise on the issues of air emissions; Annex B lists the interviews we conducted. We also met with company management to understand the actions the company has taken and is taking to address emissions of carbon dioxide and other air emissions. Management also presented to the Policy Committee of the Board a current assessment of the technologies available to the company for reducing these emissions. Finally, the subcommittee requested and reviewed analyses of the costs of several control scenarios. We shared a draft of this report with the AEP Board of Directors in July 2004.

Our findings are presented in the balance of this report in four sections:

- A discussion of possible scenarios for the regulation of carbon dioxide and other emissions;
- A review of the actions available to the company for controlling these emissions;
- The results of the economic analyses of various control scenarios; and
- Our assessment of the challenges faced by the company and the key actions we believe important in meeting the challenges successfully.

The content of these sections includes, but is not limited to, specific topics that we agreed to address in our discussions with the proponents of the shareholder resolution.

Our assessment concludes that the company has taken and is taking actions that constitute a solid foundation for future efforts to address the intersection between environmental policy and business opportunity. We recognize that there is much still to be done, and we outline measures to guide the company in the path ahead.

The subcommittee is grateful to the proponents of the shareholder resolution, the other stakeholders whom we interviewed, and to management for their advice, information and insights on this important matter.

Donald M. Carlton
John P. DesBarres
Robert W. Fri, Chair
An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies

2. Policy Context

The American Electric Power System (AEP) is the largest electric power generator in the United States, with a diverse portfolio of renewable, nuclear, and fossil fuel-fired generation assets. Due to the plentiful coal reserves in the eleven states in which AEP operates, the company relies heavily on coal as the primary energy source to generate a reliable supply of affordable electricity for its customers. The company recognizes the significant responsibility it carries within the power sector, specifically, and U.S. industry, in general, to minimize the economic and environmental impacts of its decisions. Among the most significant economic drivers for coal-based generators are current and future environmental policies, particularly air quality policies and programs.

In particular, limits on currently regulated air emissions are likely to become increasingly stringent and there is the possibility of mandatory controls on the emission of greenhouse gases. With respect to the former, the company’s ability to develop a strategy to further reduce air emissions at the lowest cost to its consumers and shareholders over the long term is complicated by uncertainties regarding the nature and scope of currently proposed requirements, and the likelihood and timing of additional future emission reduction requirements. In the U.S., mandatory restrictions on greenhouse gas emissions remain a matter of active public debate. It is impossible to predict when or what form of greenhouse gas regulations might be imposed. At the same time, proposed legislation to require relatively modest initial reductions in greenhouse gas emissions appears to be attracting increasing bipartisan Congressional interest. The extent to which other manufacturing countries join in efforts to reduce greenhouse gases will affect the likelihood of Congressional passage of such measures.

As a result, there are significant business issues when it comes to mitigating the economic impacts associated with environmental issues. To address these business issues in the public policy context, the subcommittee examined several scenarios for the regulation of both currently regulated air emissions and greenhouse gases. These scenarios were developed by Van Ness Feldman, are summarized here and described with greater detail in Annex C:

**Currently Regulated Emissions**

- **Current Administration Regulatory Policy**
  - Currently proposed Clean Air Interstate Rule, Utility Mercury Reduction Rules
  - State regulatory programs to address remaining local non-attainment areas
  - Potentially adverse outcome in NSR litigation
- **Litigation and Piecemeal Implementation**
  - EPA rulemakings invalidated by D.C. Circuit Court
  - Accelerated SO2, NOx, and mercury reduction timetables
  - Increased mercury control stringency; no mercury emissions trading
  - State regulatory programs to address remaining local non-attainment areas
  - Potentially adverse outcome in NSR litigation
- **Governmental Policy Change**
  - Change in Administration
  - Accelerated SO2, NOx, and mercury reduction timetables
  - Increased mercury control stringency; no mercury emissions trading
  - State regulatory programs to address remaining local non-attainment areas
  - Potentially adverse outcome in NSR litigation
2. Policy Context

**Greenhouse Gases**

- Federal Voluntary Policy; Regulatory Programs in Certain States
  - Continuation of Administration’s voluntary greenhouse gas programs
  - State-level greenhouse gas regulations and renewable portfolio standards
- Multi-Emissions Program with CO₂ regulation
  - Enactment of a program with limits on SO₂, NOₓ, mercury, and CO₂ based on Senator Carper’s proposed Clean Air Planning Act of 2003
- Economy-wide Greenhouse Gas (GHG) Cap-and-Trade Program
  - Enactment of an economy-wide greenhouse gas cap-and-trade program based on the amendment proposed by Senator McCain and Senator Lieberman that is a modification of their Climate Stewardship Act of 2003, S. 139
- More Stringent Economy-wide GHG Cap-and-Trade Program
  - The McCain-Lieberman proposal with a 1990 target and then a declining cap

For currently regulated air emissions, it appears that future regulatory programs will require substantial reductions in the company’s emissions of SO₂, NOₓ, and mercury from its coal-fired fleet over the next 15 years. Whether the programs that are ultimately implemented reflect the Administration’s current regulatory proposals, litigation and piecemeal implementation, or governmental policy change, including new legislation, emission limitations are nearly certain to become increasingly stringent. However, the economic impacts on the company resulting from any of these plausible policy scenarios depend on the inherent variability in costs and performance of new generation and pollution control technologies, the variability in future fuel prices, and in large part on five major environmental and regulatory policy factors:

- The stringency of emissions reduction requirements;
- The timetable for emissions reductions;
- The availability of trading of emission reduction credits;
- The methodology of allowance allocation, if there is trading; and
- The interaction with policies governing greenhouse gas emissions.

The near-term costs to the company for compliance with the Administration’s currently proposed regulatory programs have been estimated at approximately $3.5 billion by 2010. In the mid-to-long-term, however, future compliance costs are uncertain for all of the reasons described above. Worst-case assumptions that significantly increase compliance costs include the adoption of programs that: (i) mandate unit-specific control requirements, reduce the flexibility and cost-effectiveness of trading programs, and restrict the use of associated allowances; (ii) impose uncoordinated compliance schedules for currently regulated air emissions that would eliminate or curtail “co-benefits”¹ from control technology investments; and, (iii) conventional control technology investments that become stranded² by the later adoption of even more stringent emission limitations and/or greenhouse gas emission controls that would force premature retirement of these assets before the end of their economic lives.

¹ The term “co-benefits” describes reductions in emissions that are obtained through the combined use of different pollution control technologies. For example, the installation of both selective catalytic reduction (SCR) to reduce NOₓ emissions and flue gas desulfurization (FGD) systems to control SO₂ emissions could also reduce mercury emissions at little to no additional cost.

² The term “stranded” here refers to assets that are forced into premature retirement before their capital costs can be recovered, due to unforeseen greenhouse gas emissions restrictions that render existing plants inoperable.
2. Policy Context

With regard to global climate change policy, the immediate future of greenhouse gas regulations remains highly uncertain, but mandatory carbon constraints in the long-term appear probable. Although the understanding of the science underlying the global climate system continues to evolve, the absence of a foreseeable precipitating event and past reluctance by Congress to consider mandatory restrictions on U.S. emissions in the absence of comprehensive and coordinated global action makes it difficult to expect rapid emergence of the near-term political consensus that could motivate a major policy-level response to global climate change. Consequently, the likelihood for costly, mandated reductions in carbon emissions in the next few years appears small, although interest and awareness in the topic are likely to continue to grow. This report considers the three greenhouse gas policy scenarios listed on the preceding page to represent the most plausible outcomes on this topic in the near-to-mid term.3

Driven by AEP’s long-term planning obligations, the company’s position statement on global climate change states that “enough is known about the science and environmental impacts of climate change for us to take actions to address its consequences.” The company has demonstrated this commitment by developing and implementing a broad portfolio of actions to reduce, avoid or sequester greenhouse gas emissions, beginning in 1995. The company also has contributed and continues to contribute to the development of low/no-carbon energy technologies and has been proactive in the policy debate to establish the framework for international and domestic policies aimed at ultimately stabilizing atmospheric greenhouse gas concentrations.

A key challenge facing the company lies in determining the extent to which it can increase its voluntary greenhouse gas abatement investments since unilateral actions will yield little in terms of demonstrable environmental benefits and could place the company and possibly its commercial and industrial customers at a competitive disadvantage.

The interaction between policies governing currently regulated air emissions and greenhouse gases also merits close attention. While additional reductions of currently regulated emissions contribute to improved air quality, it is worth noting that such pollution control equipment uses energy that reduces the efficiency of power generation stations, thereby raising greenhouse gas emission rates. Furthermore, large-scale investments in pollution control can only be undertaken prudently if there is little risk of such investments becoming “stranded” by future environmental or economic mandates, including carbon constraints. Hence, clean air policies interact with global climate change policies in ways that are complex. The strategic options that should be considered by the company are those that will optimize its ability to respond flexibly and cost-effectively to developments on both fronts.

3 While this assessment did not seek to quantify the probabilities of various policy scenarios, it should be noted that the greenhouse gas scenarios do not, in the view of the subcommittee and many of the experts consulted, share equal likelihood of becoming reality. In particular, it is felt that greenhouse gas policy scenarios #1 and #3 appear more plausible than scenario #2. Furthermore, recognition of these scenarios as possible does not constitute endorsement of any of these hypothetical outcomes.
In this complex and uncertain public policy environment, the company can pursue four broad strategies for controlling emissions — installing control technologies on existing power plants, changing the composition of the generation fleet, managing its demand profile, and seeking emission reductions off-system. All of these strategies are actively employed in meeting current and foreseeable control requirements. While the same strategies would be expected to apply to less certain future requirements, these tools are not as fully developed in terms of addressing greenhouse gas emissions as they are for currently regulated air emissions.

Control Technologies
Emission control technologies involve the retrofitting of complex chemical-based systems onto existing power plants to capture and remove targeted pollutants, thus reducing emissions of these substances. The effectiveness of these technologies varies depending on the particular pollutants being addressed. Flue gas desulfurization (FGD) systems and selective catalytic reduction (SCR) systems have been demonstrated to achieve very high levels of removal for SO\textsubscript{2} and NO\textsubscript{x}, respectively. However, capture and removal of mercury presents unique challenges. The combined operation of FGDs and SCRs with certain coal types can result in significant “co-benefit” mercury control. Very high levels of mercury control or reductions at facilities that do not have both FGDs and SCRs likely will require stand-alone mercury control technologies that U.S. EPA and U.S. DOE have indicated are not commercially available nor have been demonstrated in large-scale operation on the full spectrum of coals.

The most formidable challenges are presented by carbon capture, since carbon is an integral component of fossil fuels. Capturing carbon dioxide emissions requires complex, expensive, and energy-intensive technologies for existing pulverized coal plants. Next-generation fossil-fuel-based power plants that are better suited for carbon capture are nearing the point of commercial feasibility. However, the efficacy of permanent, ecologically safe disposal of carbon dioxide in geologic formations has not yet been proven.

Fleet Composition
Changing the composition of AEP’s generation fleet represents another option for addressing the company’s air emissions. In 2000, American Electric Power merged with Central and South West Corporation, achieving significant diversification in the fuel mix of power generation assets. Prior to the merger, AEP generated its electricity using 90% coal, 9% nuclear, and 1% hydroelectric power. After the merger, these figures changed to 65% coal/lignite, 7% nuclear, 26% gas, and 2% hydroelectric and other. While fuel diversification merits attention for many reasons, experience has shown that markets rather than policies are more efficient instruments to guide investment decisions for new generation capacity additions. Indeed, as AEP’s existing generation assets approach the latter stages of their economic lives, potential changes in the composition of the company’s fleet will become a major consideration. The company faces significant
challenges and opportunities in maximizing the value of existing assets while also managing the retirement and replacement of these facilities.

New technologies will be needed in the future as AEP seeks to both replace aging capacity and meet growing demand in a cost-effective, sustainable manner. Leading options for new generation include systems based on fossil fuels and renewable energy. Nuclear power also holds potential, although it faces considerable challenges. Additional, complementary technological considerations include the potential roles of distributed resources, storage technologies, and carbon capture and sequestration. These technologies are discussed in greater detail in Annex D.

As a major operator of low-cost baseload power plants, the company has new fossil-fuel-based generation options under consideration that include advanced pulverized coal facilities, which have been the traditional technology used to convert coal into electricity in the absence of CO₂ constraints; circulating fluidized bed plants, which work best with low-BTU coals; natural gas combined cycle plants, which involve the least up-front capital but are vulnerable to high gas prices, as currently is the case, as well as gas price volatility; and integrated gasification combined cycle systems, which appear to be approaching commercial viability.

Integrated gasification combined cycle (IGCC) is of particular interest to AEP, in light of the abundance, accessibility, and affordability of high rank coals for the company. IGCC also appears well-positioned for integration of carbon capture and sequestration technologies, which will be a critical measure in mitigating greenhouse gas emissions. While technology risks, performance uncertainties, and capital costs remain formidable at this early stage in IGCC’s development, AEP also recognizes sizable operational, policy, and economic benefits that this technology potentially could deliver as the next generation of power generation assets. Weighing these costs and benefits, the company has committed to emerging as a leader and first-mover in advancing IGCC into the mainstream of power generation.

Renewable energy systems represent a key component of the portfolio of options considered by the company. In the near term, biomass co-firing in coal-fired power plants and wind energy are the primary options for generating electricity on a large scale from renewable energy, delivering attractive CO₂ benefits in a potentially carbon-constrained policy environment. Already, the company ranks among the leading generators of wind power in the United States. While renewable energy technologies continue to achieve impressive improvements in performance and cost, resource availability in terms of capital and land could become a limiting factor for large-scale deployment of biomass and wind technologies both in the AEP fleet and in the country as a whole.

Nuclear power holds promise as an option for electric power generation, but also faces significant challenges that must be addressed. Currently accounting for approximately one-fifth of U.S. electricity, nuclear power serves as a critical resource for baseload power. Next-generation reactor designs could offer improvements over the already-high performance of current plants, thus preserving, and perhaps even expanding, the emission-free fleet of nuclear power plants in the country. However, issues of public acceptance, capital costs, and waste storage must be resolved if a nuclear renaissance is to occur in the U.S. The company recognizes nuclear power technologies as an important power generation option and supports a proactive approach from government and industry to addressing the challenges facing nuclear power.
Additional technologies complement these power generation options. Distributed resources and storage technologies offer potential advances in such areas as peak management, asset utilization, power quality, grid stabilization, energy arbitrage, and customer commercial services, but the technological race continues as no clear winners have yet emerged to fill the niches that distributed resources and energy storage could fill. Carbon capture and sequestration, in contrast, would have to be widely deployed eventually if carbon constraints become sufficiently stringent. Yet these technologies remain in the early stages of development and face challenges in terms of technology R&D and societal acceptance before they can reach commercial availability, much less widespread deployment. The high costs of capturing carbon dioxide from flue gases impose major penalties on existing pulverized coal power plants, potentially raising the cost of electricity between 30 and 50 percent. In this context, IGCC promises to be the most conducive technology for carbon capture and sequestration. Alternatively, IGCC flue gas streams also could prove to be amenable to direct sequestration, which would obviate the need for costly carbon capture technologies.

Demand-Side Options
Traditional demand-side options appear limited in their usefulness at AEP for reducing currently regulated emissions and greenhouse gases for two main reasons. First, in the course of the evolution of the policy and market landscape of the power sector over the past few decades, a notable shift away from demand-side management and toward market-driven approaches has occurred. In particular, many regulators on state public service commissions now seem to emphasize harnessing market forces to deliver savings to ratepayers over reducing demand for the same end.

The result is that conventional demand-side management programs no longer delivered returns on investment in most cases within AEP’s service territory, especially given AEP’s abundant supply of low-cost electricity. Second, the advent of wholesale competition and regional transmission integration in the electric power industry has led to the natural evolution of AEP as a low-cost generator into a major player at the wholesale and regional levels. Maximizing generation output from existing assets to participate in wholesale and regional markets means capitalizing on the company’s natural comparative advantages to the benefit of shareholders and customers. Improvements in power plant availability also can lead to reductions in emissions per unit of electricity. While this would represent a step forward in efficiency that results in tangible environmental benefits, overall emissions still could increase, as the net increase in generation would make this environmental improvement difficult to discern.

Promising alternatives to traditional direct demand-side measures exist, however, including appliance and building efficiency standards. Although these instruments provide little to no direct benefit to the company, AEP believes that advances in these areas can bring about long-term energy-efficiency gains in the overall structure of the economy that in turn contribute to lower overall rates of both currently regulated and greenhouse gas emissions.

Off-system Reductions
Off-system reductions of greenhouse gas emissions, premised on global trading of greenhouse gas emissions reductions credits, represent an innovative approach to addressing global climate change. Building upon the concept of emissions trading that has proven its efficacy and efficiency through U.S. EPA’s acid rain control
program, the company has played a pioneering role in demonstrating the effectiveness of such approaches to mitigate greenhouse gas emissions. Examples of such off-system reductions include enhancing or protecting uptake of carbon dioxide in threatened rainforests or improving the efficiency of power plants in developing countries. While such measures have not been employed in traditional air quality programs, which have a local or more regional focus, off-system reductions of greenhouse gas emissions effectively contribute to the necessary global reductions in carbon emissions and deliver many ancillary benefits in terms of sustainable development and biodiversity protection that complement these projects’ cost-effective mitigation of greenhouse gases.

The importance of off-system reductions to the company is represented by AEP’s commitment to and participation in the Chicago Climate Exchange (CCX). As a founding member of this pioneering effort in greenhouse gas emissions trading, AEP voluntarily has committed to cap and reduce or offset its total greenhouse gas emissions by 4 percent over four years. These reductions began in 2003 with a 1 percent reduction from baseline emissions (average of 1998-2001) and will continue with an additional 1 percent reduction each year until the company has reduced its greenhouse gas emissions by 4 percent from the baseline in 2006. Through this commitment, the company expects to reduce or offset an estimated 18 million cumulative tons of carbon dioxide or carbon dioxide ‘equivalent’ emissions, based on current levels of emissions. AEP plans to meet its CCX commitment cost-effectively through a broad portfolio of actions, including both on-system actions such as plant efficiency improvements and off-system projects such as reforestation projects and the purchase of emission reduction credits from other CCX participants. Already, the company is ahead of its 2003 commitment, reflecting the closing and/or mothballing of inefficient gas steam units in Texas, improved operation and utilization of its Cook Nuclear Plant, and continued investments in reforestation projects.

Because climate change is truly a global challenge that requires a global solution, off-system reductions represent an efficient and effective near-term option for greenhouse gas mitigation. Additionally, off-system reductions also could provide the valuable time necessary for the longer-term, larger-scale technology revolution that will be necessary to decouple energy use from carbon emissions. These conclusions rest on the premises that (a) the atmosphere is unable to distinguish between the origins of greenhouse gases and (b) the marginal costs of greenhouse gas abatement vary widely between industrialized and developing countries. Furthermore, participation in markets in which greenhouse gas emission credits are traded requires the company to develop data on the internal costs of greenhouse gas reductions, which is an important step toward building the foundation for retrofits, retirements, and replacements within the company’s generation fleet. Off-system reductions of greenhouse gas emissions work in the interest of the company’s shareholders, customers, and government and community stakeholders as a highly cost-effective instrument for addressing global climate change.
At the request of the subcommittee, management conducted quantitative analyses of the potential costs of currently proposed emissions control regimes. A summary description of these analyses is provided below. A more detailed description of the purpose of the analysis, scenarios examined, analytic results of the study and detail on the assumptions employed and uncertainties evaluated is presented in Annex E.

These analyses specifically projected costs associated with compliance with the following combinations of the policy scenarios described earlier in this report:

- The Administration’s current proposals on already-regulated pollutants;
- The Administration’s policies on conventional pollutants coupled with immediate passage of the McCain-Lieberman amendment, under which AEP’s carbon dioxide emissions would be capped at 2000 levels by 2010;
- The Administration’s policies followed by enactment of the McCain-Lieberman amendment in 2009 with compliance in 2014; and
- The Carper bill (S. 843) being enacted in lieu of current Administration policy.

Additional sensitivity analyses were completed on the impacts of varying CO₂ permit prices for these scenarios. It should be noted that analysis of these scenarios does not reflect upon the likelihood of any of these proposals becoming legally binding.

A number of important analytical assumptions merit discussion. All scenarios assumed that allowances would be allocated to power plants on a historical basis rather than auctioned. Potential allowance auctions, which have been considered particularly in the case of greenhouse gas limits, could raise enormously AEP’s cost of reducing emissions. They also could substantially raise electricity rates for customers in the Midwest. This effect is stated here, and described further in Annex E, rather than being included in the quantitative analyses.¹

Assumptions also were made with regard to future fuel prices, pollution control and new plant costs, and emission rates, but it should be noted that mercury-specific controls have not been demonstrated commercially at coal-fired units and may be technically infeasible by the 2009 date modeled for compliance with the Carper bill. These assumptions are documented in Annex E.

The company has developed a robust least-cost plan for meeting the Administration’s balanced requirements for SO₂, NOₓ, and mercury.

Implementing this plan requires an investment of

¹ While the possibility of auctions exists in future legislation, particularly for greenhouse gases, the issue remains highly contentious. In general, countries that are subject to mandatory greenhouse gas reductions under the Kyoto Protocol have opted for small auctions, if at all. For example, the European Union emissions allocation plan for Kyoto compliance limits auctioned allowances to no more than 5 percent of total allocations during 2005-2007 and no more than 10 percent during 2008-2012. Several EU countries, most notably Germany and Spain, have opted not to have allowance auctions at all. Finally, in the U.S., the severe regional distributive consequences to states with extensive coal-based generation in the Midwest and Southeast make passage of a significant auction scheme in new legislation unlikely.
approximately $3.5 billion through 2010, $5 billion through 2020, all with a net present value (NPV) of $2.6 billion, a figure that depends in part on the efficiency of the control regime but represents the base case. Compliance with the greenhouse gas control provisions of the McCain-Lieberman amendment appears possible with existing technologies at net present value costs between $0.5 and $0.9 billion, additional to the base case. The Carper bill would require much higher additional costs, between $3.0 and $6.4 billion. Again, these costs for compliance with greenhouse gas policies depend significantly on the economic efficiency of the control regime that is adopted. Table 1 summarizes these figures.

**NPV of AEP costs above base case,** 2004-2030

<table>
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<th>Carbon permit price sensitivity</th>
<th>McCain-Lieberman ’04 passage</th>
<th>’09 passage</th>
<th>Carper ’04 passage</th>
<th>’09 passage</th>
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<tr>
<td>High</td>
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* base case: EPA Regulatory = $2.6B

**Table 1: Potential compliance costs for greenhouse gas policy scenarios**

Compliance costs with the McCain-Lieberman proposal are relatively unaffected by the timing of its passage and implementation. This can be attributed to the robustness of the investment decisions made over the next 6-8 years to comply with the Administration policies for conventional pollutants in the absence of any carbon constraints as well as across both scenarios involving the McCain-Lieberman amendment. Simply put, the near-term investments in scrubbers, SCRs and other pollution control equipment are being made at the lowest-cost plants, which are the most economic to retrofit and will continue to operate with or without CO₂ constraints under McCain-Lieberman. It is only when more marginal retrofit decisions need to be made after this period that the inclusion of a CO₂ constraint would affect these decisions.

McCain-Lieberman compliance is expected to require reductions and/or offsets of approximately 10 million tons of CO₂ by 2020. Few, if any, costs are expected to be stranded by delayed implementation of McCain-Lieberman, and this delay, even without foresight of its enactment, actually results in slightly lower costs for carbon compliance, because the costs of meeting the carbon constraints are delayed. Looking beyond 2010 – 12, it is foreseen that the McCain-Lieberman requirements would reduce deployment of scrubbing and carbon injection as the fleet composition shifts to greater reliance on integrated gasification combined cycle (post 2016 to allow for “Nth of a kind” availability), natural gas combined cycle, and wind power. Of course, it is quite possible that the McCain-Lieberman reduction requirement could be tightened in the future (e.g., in the post 2020 period). This could lead to dramatically higher costs to the company and potentially create a need to recover some of the remaining unamortized portion of the environmental control investments for currently regulated emissions at some AEP power plants. Figure 1 illustrates the actions that the company is modeled to take in order to comply with currently proposed regulations (EPA’s SO₂, NOₓ, and mercury rules) and the McCain-Lieberman proposal (2009 passage) under both low and high CO₂ price sensitivities.

The Carper bill presents more formidable emission

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5 Costs in this section refer to fuel, O&M and capital expenditures, new plant capital, retrofit pollution control, and CO₂ permit purchases

6 “Nth of a kind” refers to the assumption that the deployment of several demonstration-scale units reveals technical improvement opportunities that lower the cost of widespread deployment of full-scale generation technologies.
reduction requirements, on the order of being six to seven times more expensive to the company in a range of $3.0-$6.4 billion in net present value costs. The two major factors driving these costs are: (1) the accelerated

**CO₂ Offsets/Reductions in 2002: About 10mm tons**

**Figure 1: AEP CO₂ Emission Reductions (MM tons CO₂)**

allowances to nuclear, gas and hydro units than they will need to comply, allowances which operators of coal-fired units such as AEP will have to purchase. From a national perspective, states that depend on coal-fired generation would effectively subsidize electricity rates for those states that rely more heavily on nuclear, gas and/or hydroelectric power.

AEP's high costs under the Carper bill are driven by the carbon dioxide allocation scheme. In this latter case, although the Carper bill will achieve fewer national reductions of greenhouse gases than the McCain-Lieberman amendment (since it singles out the electric utility sector rather than adopting an economy-wide approach), for AEP, it will require approximately 6 times as many reductions. In short, the costs to offset or reduce a very large amount of CO₂ emissions, reaching 58 million tons per year by 2020, result in almost 2/3 of the Carper bill's costs being associated with these purchases and/or offsets. This example demonstrates how the economic impacts of greenhouse gas policies on the company are affected by policy design considerations that are independent of the actual greenhouse gas reduction benefits that would be achieved.

timing and increased stringency of the Carper bill's requirements for currently regulated emissions, particularly mercury, result in increased expenditures on pollution control equipment; and (2) allocating CO₂ allowances based on generation output. In terms of the latter, the Carper bill will provide many more emission
5. Evaluation

Annex F summarizes the actions that the company has taken and is taking to address the issues of greenhouse gas and other emissions. While the list is impressive, the chief value of these efforts lies in the foundation that has been built for the company’s future management of these environmental issues. Accordingly, our evaluation of the company’s actions to mitigate the economic impacts of emission controls is prospective: building on this foundation, what should the company do to maintain and enhance overall shareholder value? We begin by describing the challenge the company faces as it invests significant capital in these controls over the next few years. We then identify the responses we believe are essential to meeting these challenges.

The Challenge

The central challenge the company faces is that of making decisions about large investments in long-lived assets in a setting of uncertain public policy and rapidly evolving technology. The dilemma is that requirements and technology that can change fairly rapidly increase the risk of making an investment that fails to remain productive over its useful life. For the reasons summarized below, we believe that this situation is likely to persist for a considerable time.

The near-term requirements for the control of SO$_2$ and NO$_x$ are reasonably well known. The exact requirement for controlling mercury emissions is less clear and remains controversial. The need for even more stringent future controls on currently regulated air emissions from power plants is speculative at this point. However, because AEP must plan for the long-term, experience suggests that the company should expect to make further reductions of these emissions over time.

Some initial mandatory reductions of greenhouse gas emissions are likely in the next decade, although the stringency and the timing of such reductions are difficult to estimate with any confidence. Beyond this initial step, we cannot predict the timing, stringency, or structure of a program that would be needed to reduce greenhouse gas emissions to a level consistent with maintaining an acceptable concentration of greenhouse gases in the atmosphere. Nevertheless, the possibility of such requirements is real and needs to be taken into account in making long-term investment decisions.

The technological response to these requirements is uncertain, as well. AEP has considerable experience with designing and operating technology to control SO$_2$ and NO$_x$. It expects to invest $3.5 billion to meet near-term control requirements. The cost of reducing these emissions is increasing, however. The cost of additional emissions reductions is expected to grow, in part, because the marginal costs of removing the next increment of emissions tends naturally to rise. In addition, physical space limitations, parasitic load demands, and other engineering factors are also contributing to the increasing cost — particularly for smaller and older units in the AEP generation fleet. Technology for reducing mercury emissions is less well developed, and its costs could be considerable. And if more stringent controls of these currently regulated emissions do indeed come into being several years hence, we cannot dismiss the possibility that the least-
cost response would be to shift to a new generation of control technology.

Responding to climate change is even more problematic. Analyses developed for this report show that the company could likely make modest reductions in greenhouse gas emissions and could do so anytime within the next several years without significant risk to its investment in pollution control technology for currently regulated emissions. However, to go beyond this first step would require the extensive deployment of new technologies, including Integrated Gasification Combined Cycle (IGCC) generation from coal and renewable sources such as wind, solar power and biomass fuels.

**The Response**

The company’s goals are to comply with mandated emission requirements; to maintain its competitive position as a low-cost, reliable supplier of electricity; and to attract the necessary capital for these purposes. The economic impact of controlling greenhouse gas and other emissions thus depends on the company’s ability to meet these goals in a fluid business setting. We believe that the actions the company has taken in anticipation of the control requirements described above have put it in a position to manage effectively their associated economic impact. The company should build on this foundation to fashion an action program to that end. We outline below the key elements of this program as we see them.

**Design of control regimes:** The design of environmental regulatory programs profoundly affects the cost of meeting the emission reduction requirements. For example, cap-and-trade programs, such as the one in place for SO2 controls, provide opportunities to seek out the most efficient controls. Similar program designs are economically efficient for all regulated emissions, but are even more crucial for greenhouse gas control programs. The company emits carbon dioxide by burning coal, natural gas and fuel oil in its generating fleet. However, the lowest-cost and most-effective controls of greenhouse gases may occur elsewhere — in reducing other kinds of greenhouse gases (such as methane), by enhancing or protecting carbon sequestration resources, or by cutting carbon emissions outside the AEP System. We believe that flexible and comprehensive control regimes of this sort should be a major tool in mitigating the economic impact of greenhouse gas and other emission reduction programs.

Through its actions to date, the company has accumulated a significant amount of experience in the design of programs that would minimize the cost of compliance with reductions of greenhouse gases and other emissions. Notable among this experience are the company’s leadership and participation in the Chicago Climate Exchange and the International Emissions Trading Association, its demonstrations of terrestrial sequestration projects and of cooperative projects with other countries, and its support of research by the U.S. Department of Energy, Pew Center for Global Climate Change, the Electric Power Research Institute, and other organizations. We believe that the company is particularly well positioned to build on this experience to advocate effectively in policy and regulatory forums for the most efficient program designs, not only for the environmental benefits, but also for the benefits to its customers over the long-term.

Of special interest is the design of a program for greenhouse gases. At some point in the future, governments around the world are likely to agree upon initial implementation of a modest mandated constraint on greenhouse gas emissions. Analyses prepared for this report suggest that AEP could meet a reasonable constraint at significant but manageable costs.
5. Evaluation

— provided that the program was efficiently designed. However, it also appears that the timing of this initial program has little effect on the cost to the company of proceeding now to invest in control equipment to meet new requirements for controlling other regulated emissions.

The intricate design details of greenhouse gas control programs bear significant influence on the cost borne by the company, and therefore its customers, to comply. Important to the company will be persuasive, proactive advocacy of positive policy positions that ensure that the rules governing such programs will operate in a transparent, fair, and cost-effective manner that works in the interests of the company’s shareholders, customers, and stakeholders, as well as the U.S. economy vis-à-vis the world.

**Technology leadership:** The central technology challenge for AEP is to preserve its ability to burn coal economically while meeting increasingly stringent emission control requirements. Management has closely followed the development of technologies of this type for several years. Based on assessments prepared by company and other analysts, IGCC technology appears to have the greatest potential for meeting AEP’s long-term goals. During the course of our evaluation, the company concluded that accelerating IGCC technology development to reach commercial availability by 2015 or before must become a high priority for AEP. As a result, the company has committed to being the industry leader in developing IGCC technology and already is forging ahead to develop partnerships and agreements to make IGCC a viable option for AEP’s next generation of new power plants. We strongly support this initiative.

IGCC technology has advantages both economically and for the control of regulated emissions that, in our opinion, justify this ambitious program. However, the technology would also be highly desirable in a carbon-constrained world, since its carbon dioxide stream should be much easier, and therefore less costly, to capture than one from a pulverized coal plant. As part of its IGCC development program, the company should therefore actively encourage research that would investigate and, if feasible, demonstrate the capture and disposal of carbon dioxide emissions from IGCC technology. AEP has supported research into the management of carbon dioxide, notably in the sequestration research that is being conducted at its Mountaineer plant, and in doing so, has positioned itself well to help shape a national program on this subject.

**Excellence in plant operations:** The ability to efficiently operate large power plants with complex emission control equipment is an important strength. Achieving highly reliable and efficient operation of such equipment also has the benefit of maximizing the availability of retrofitted power plants to sell excess generation into wholesale markets. But consistently operating emission-controlled plants at high capacity factors is difficult at best, requiring mastery of not only traditional power plant operations but also the management of complex chemical reactions at very high mass flows. Similarly, as systems become more complex, the challenges of information processing grow as well. The company has considerable experience in plant operations, but will need to refine its capabilities as the complexity of the control technology multiplies. AEP must be open to acquiring skills not common to utility operations, such as chemical engineering and advanced system control software. Such efforts should help to achieve cost-effective solutions to these important challenges.

\* Note the large difference in the costs of meeting the different control scenarios discussed in the previous section.\*
Sophisticated decision-making tools: A variety of options are available to the company for complying with emission limits of both currently regulated and greenhouse gas emissions. These include investment in control technology at AEP power plants, the purchase of allowances and other off-system emission reductions, changes in fuel mix, and the retirement and/or replacement of elements of the generation fleet. The company must, therefore, engage in an exceedingly complex decision-making process to identify the mix of options that will minimize the cost to the consumer while at the same time being robust with respect to the uncertainty in the regulatory process.

We believe that one of the company’s most important accomplishments has been the development of the Multi-Emission Compliance Optimization Model (MECO). This proprietary model is a sophisticated analytic tool that allows the company to systematically weigh the costs and risks of a wide variety of options. Our non-technical review of the model and its application in decision-making at AEP leads us to believe that the development of MECO is a distinctive strength for the company. As such we encourage its continued use as a guide to the company’s major investment decisions, as well as its ongoing refinement to ensure its relevance to the evolving structure of the electric power industry.

While MECO serves as the company’s principal analytic tool for environmental policy analysis, it faces the same limitations encountered by other quantitative tools. Recognizing the inherent constraints posed by models that work only within defined parameters, the company employs a diversity of computer models to corroborate and complement the analyses of MECO. AEP also considers the output of these systems as just one of many inputs, both quantitative and qualitative, that factor into the complex decision-making process that is used to evaluate strategic options and determine courses of action.

Transparency: Both the public policy and technology settings in which AEP operates are complex to the point of obscurity. Yet regulators, investors, legislators, government officials, customers, and other stakeholders need to have a clear idea of what AEP is doing to control emissions efficiently, and why it has adopted its chosen approach. While the company has been open in its actions to date, we believe that efforts to make its actions transparent and understandable to stakeholders will be critical going forward.

For example, the decision-making tools and associated decision-making processes must be credible to, and accepted by, a variety of stakeholders — especially those who regulate the company’s rates. Certain tools, like MECO, are proprietary and highly technical, making it difficult for stakeholders to judge their merits. We believe the company should consult with these stakeholders to identify the steps it should take to build the necessary understanding and acceptance of these tools, including appropriate protections of the company’s investment and the commercial advantage inherent in the development of sophisticated proprietary models like MECO.

Partnerships: We are convinced that AEP is venturing into new territory as it works out options to control...
greenhouse gas and other emissions. We strongly urge the company not to go it alone in this venture, but to find partners along the way. One reason is that many of the skills necessary to succeed are not native to utility operations. We have noted the need for chemical engineering skills in operating equipment to control regulated emissions. The same need for new skills is present in the IGCC initiative described above. Finding ways to partner with those who already have these skills seems to us more effective than developing them in house.

Another need for partnership lies in the crafting of emission control programs. In this case, everyone necessary to make the program work needs to be involved. As an example, state regulators must be convinced that off-system investments in greenhouse gas emissions abatement in other countries, assuming they are verifiable, make economic sense to their ratepayers. Such cooperation will be necessary to ensure that economically-efficient measures maximize value for shareholders and minimize costs to ratepayers.

In summary:
We conclude that the actions that AEP has taken over the last decade constitute a solid foundation for the company’s future efforts to address the intersection between environmental policy and business opportunities. The challenge now is to build on this foundation in a way that makes economic sense in a setting of policy uncertainty and change. Forceful and serious advocacy of highly efficient control programs, proactive leadership in technology development and operation, discipline in capital allocation decisions, openness to partnerships in technology and policy, and continued transparency of action are, we believe, the essential elements of the path ahead.
Annexes
Annex A: Correspondence Between the Company and the Shareholder Resolution Proponents
An Assessment of AEP’s Actions to Mitigate the Economic Impacts of Emissions Policies / 19

Annex A

State of Connecticut
Office of the Treasurer

November 18, 2003

Ms. Susan Tomasky
Corporate Secretary
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

Dear Ms. Tomasky:

The purpose of this letter is to submit the attached shareholder resolution on behalf of the Connecticut Retirement Plans & Trust Funds ("CRPTF") for consideration and action by shareholders at the next annual meeting of American Electric Power (AEP).

As the Deputy State Treasurer, I hereby certify that the CRPTF has been a shareholder of the minimum number of shares required of your company for the past year. Furthermore, as of November 17, 2003, the CRPTF held 104,940 shares of AEP stock valued at approximately $2,833,000. The CRPTF will continue to own AEP shares through the annual meeting date.

Please do not hesitate to contact Donald Kirshbaum, Investment Officer for Policy at (860) 702-3164, if you have any questions or comments concerning this resolution.

Sincerely,

Howard Rifkin
Deputy Treasurer

Attachment

cc: Dale Heydlauff, Senior Vice President, Environmental Affairs
Julie Sloat, Manager, Investor Relations

55 Elm Street, Hartford, Connecticut 06106-1773. Telephone: (860) 702-3000
An Equal Opportunity Employer
RESOLUTION REQUESTING A REPORT ON THE ECONOMIC IMPACT ON OUR COMPANY OF REDUCING CARBON EMISSIONS

WHEREAS:

In 2001, power plants owned and operated by AEP emitted more carbon dioxide, sulfur dioxide, nitrogen oxide and mercury than the powers plants of any other electric utility company in the United States.

U.S. power plants emit about two-thirds of the country’s sulfur dioxide emissions, one-quarter of its nitrogen oxides emissions, one-third of its mercury emissions, nearly 40 percent of its carbon dioxide emissions, and 10 percent of global carbon dioxide emissions.

Scientific studies show that each year, air pollution from U.S. power plants causes tens of thousands of premature deaths and hospitalizations, hundreds of thousands of asthma attacks, and several million lost workdays nationwide.

Studies also show that emissions from U.S. power plants have a direct impact on climate change:

- In 2001, the Intergovernmental Panel on Climate Change concluded “there is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities.”
- In 2003, the World Meteorological Organization declared, “...as the global temperatures continue to warm due to climate change, the number and intensity of extreme events might increase.”

Commitments to reduce carbon dioxide emissions are emerging. More than 100 countries have ratified the Kyoto Protocol. Massachusetts and New Hampshire have enacted legislation capping power plants’ greenhouse gases emissions. Governors of eleven states have pledged to reduce carbon dioxide emissions significantly. Renewable energy standards now exist in 13 states, indicating increasing support for non-polluting electricity sources.

In October 2003, 43 U.S. Senators voted in favor of legislation that would have capped greenhouse gas emissions from a range of industrial sectors.

Recent reports by CERES, The Carbon Disclosure Project, Innovest Strategic Value Advisors, and the Investor Responsibility Research Center demonstrate both the growing financial risks of climate change for US corporations, and inadequate risk disclosure to investors.

In April 2003, the Wall Street Journal reported, “Swiss Re is starting to ask companies applying for directors and officers liability coverage to explain how they are preparing for potential government regulation of greenhouse-gas emissions.”
Annex A

- 2 -

At the 2003 Annual Meeting of AEP, a shareholder resolution requesting a report on economic risks faced by our company due to emissions from power plants received the support of 27% of shares voted.

In their response to that resolution in the proxy, our directors told shareholders that “substantial reductions in emissions can only be accomplished at a capital cost of billions of dollars.”

We believe that it is important for shareholders to understand how our company may be affected by regulatory, competitive, legal, and physical impacts of climate change, and be aware of any costs associated with the company’s actions to respond to them.

RESOLVED: AEP shareholders request that a committee of independent directors of the Board assess actions the company is taking to mitigate the economic impact on our company of increasing regulatory requirements, competitive pressures, and public expectations to significantly reduce carbon dioxide and other emissions, and issue a report to shareholders (at reasonable cost and omitting proprietary information) by September 1, 2004.

November 18, 2003
The Honorable Denise L. Nappier
Treasurer
State of Connecticut
55 Elm Street
Hartford, Connecticut 06106

February 17, 2004

Dear Treasurer Nappier:

We are writing in response to the shareholder resolution you filed at American Electric Power. In that resolution, co-filed by Christian Brothers Investment Services, Trillium Asset Management, Board of Pensions of the Evangelical Lutheran Church in America, The Pension Boards – United Church of Christ, and the United Church Foundation, you requested “that a committee of independent directors of the Board assess actions the company is taking to mitigate the economic impact on our company of increasing regulatory requirements, competitive pressures, and public expectations to significantly reduce carbon dioxide and other emissions, and issue a report to shareholders (at reasonable cost and omitting proprietary information) by September 1, 2004.” Since we share your position that management and the Board have a fiduciary duty to carefully assess and disclose to shareholders appropriate information on the company’s environmental risk exposure, we have agreed to implement your request. This letter outlines how we intend to fulfill our commitment.

In compliance with the resolution, the Board has created an ad hoc subcommittee of the Policy Committee, made up of independent directors, which will be chaired by Mr. Robert Fri. The subcommittee will conduct the requested assessment and complete the report. The other members of the subcommittee are Mr. Donald M. Carlton, Chairman of the Audit Committee of the Board, and Mr. John P. DesBarres, Chairman of the Human Resources Committee of the Board.

Mr. Fri is prepared to meet with you and representatives of the other shareholders who filed the resolution to discuss the subcommittee’s approach to the report before it is completed. We also plan to consult with other sources on what they would recommend the company do to mitigate the economic impact of future environmental control requirements in order to ensure that the company has adopted a prudent course of action.

We have also agreed to print in the proxy statement language recognizing that the resolution was filed and withdrawn based on the company’s commitment to comply with
Annex A

The statement will summarize the resolution, the process to be followed to complete the report, the general content outline of the report, and the plans for dissemination of the report to shareholders and other interested parties. A copy of the proxy language is attached as well as a list of the shareholder suggested report components that we have agreed to address in the report.

We acknowledge and appreciate the cooperative spirit in which you and the other petitioners have agreed to withdraw your shareholder resolution in light of AEP’s willingness to undertake the requested assessment.

Sincerely,

Robert W. Fri
Chairman, Policy Committee
American Electric Power Board of Directors

Michael G. Morris
President & Chief Executive Officer
American Electric Power

Attachments

Donald M. Carlton
John P. DesBarres
Julie Tanner, Christian Brothers Investment Service
Pat Zerega, Board of Pensions of the Evangelical Lutheran Church in America
Amy Muska O’Brien, The Pension Boards – United Church of Christ and United Church Foundation
Shelly Alpern, Trillium Asset Management
Dale Heydlauff, Senior Vice President, Governmental & Environmental Affairs
Julie Sloat, Manager, Investor Relations
Attachment: Shareholder Suggested Report Components

- If enacted now, the affect of Bills under consideration by the U.S. Senate on the company:
  - McCain-Lieberman Climate Stewardship Act
  - Carper Clean Air Planning Act
- Bush Administration’s Clear Skies proposal
- A comparison of enactment of Clear Skies now, with McCain Lieberman later (i.e. 3 years)
- Nationwide patchwork of state regulations on the four pollutants from the electric power sector
- Emissions trading schemes in countries where AEP has affected operations
- The economic viability and implementation timeframe of the following options for reducing emissions:
  - Investment in on-system reductions
  - Investment in offsets
  - Investments in renewable energy
  - Fuel-switching
  - Demand-side Management
  - Integrated gasification combined cycle
  - FutureGen
  - Voluntary cap and trade system
Annex B: Assessment Process

Composition of the subcommittee of the AEP Board of Directors Policy Committee

**Donald M. Carlton**  
Retired President and Chief Executive Officer, Radian International LLC, Austin, Texas  
Age 66  
Director since 2000


**John P. DesBarres**  
Investor  
Park City, Utah  
Age 64  
Director since 1997

Received an associate degree in electrical engineering from Worcester Junior College in 1960 and completed the Harvard Business School Program for Management Development in 1975 and the Massachusetts Institute of Technology Sloan School Senior Executive Program in 1984. Joined Sun Company (petroleum and natural gas) in 1963, holding various positions until 1975, when he was elected president of Sun Pipe Line Company (1979 – 1988).

**Robert W. Fri (Chair)**  
Visiting Scholar, Resources for the Future, Washington, D.C.  
Age 68  
Director since 1995

Key Dates in the Course of the Assessment

**February 23, 2004 (Columbus, OH)**
Subcommittee's first meeting to define scope of work and plan of action

Subcommittee conducts first round of interviews with outside experts

**March 18, 2004 (Washington, D.C.)**
Subcommittee conducts second round of interviews with outside experts

**April 26, 2004 (Columbus, OH)**
Subcommittee meets with management to discuss assessment timetable and process

**April 27 – 28, 2004 (Columbus, OH)**
Subcommittee conducts third round of interviews with outside experts

**May 25, 2004 (Columbus, OH)**
Subcommittee meets with management to discuss analytical capabilities and other issues; presentation delivered by management to Policy Committee on generation technology options

**May 26 – 27, 2004 (Lansing, MI & Little Rock, AR)**
Subcommittee conducts fourth and final round of interviews with outside experts

**July 26 – 28, 2004 (Canton, OH)**
AEP Board considers subcommittee’s draft report at its annual retreat

**August 31, 2004**
Final report made available to the public.

List of experts consulted in the course of the assessment

The subcommittee would like to extend special thanks to the nearly 30 experts with whom it met in the course of this assessment. These thought leaders represented a diversity of views, disciplines, and organizations, and our discussions with them served to inform the subcommittee in its work. While this report reflects only the views of its authors and not necessarily those of the experts that were consulted, the subcommittee is deeply indebted to the generosity of these individuals for sharing their expertise and insights.

- Shelley Alpern: Trillium Asset Management
- Dan Bakal: Coalition for Environmentally Responsible Economies
- Caren Byrd: Morgan Stanley
- Robert Card: United States Department of Energy
- Eileen Claussen: Pew Center on Global Climate Change
- David Conover: United States Department of Energy
- Kyle Danish: Van Ness Feldman
- Patrick Doherty: New York City, Office of the Comptroller
- James Dooley: Joint Global Change Research Institute/Battelle
- Jae Edmonds: Joint Global Change Research Institute/Pacific Northwest National Laboratory
- Denny Ellerman: Massachusetts Institute of Technology
- Stephen Fotis: Van Ness Feldman
- David Gardiner: Coalition for Environmentally Responsible Economies
- David Hawkins: Natural Resources Defense Council
- Sandra Hochstetter: Arkansas Public Service Commission
- Robert W. Jones: Morgan Stanley
- Donald Kirshbaum: State of Connecticut, Office of the Treasurer
- Peter Lark: Michigan Public Service Commission
- Brian Mormino: Subcommittee on Clean Air, Climate Change, and Nuclear Safety; Office of Senator Voinovich (R-OH)
- Tim Profeta: Office of Senator Lieberman (D-CT)
- Jim Reilly: Office of Senator Carper (D-DE)
- Joseph Romm: Center for Energy and Climate Solutions
- Evan Silverstein: SILCAP
- Julie Tanner: Christian Brothers Investment Services, Inc.
- Judy Warrick: Morgan Stanley
- Andrew Wheeler: United States Senate, Committee on Environment and Public Works; Office of Senator Inhofe (R-OK)
- Tom Wilson: Electric Power Research Institute
- Jeffrey Yingling: Morgan Stanley
1. Overview

In the course of this assessment, a range of clean air and climate policy scenarios covering the next twenty years have been examined. These scenarios were developed by Van Ness Feldman, are summarized here, and are described in greater detail in the remainder of this annex. This document concludes with an excerpt from the company’s 2003 10-K filing that addresses environmental issues.

Clean Air Policy Scenarios:
- Current Administration Regulatory Policy
- Litigation and Piecemeal Implementation
- Governmental Policy Change

Climate Policy Scenarios:
- Federal Voluntary Policy; Regulatory Programs in Certain States
- Multi-Emissions Program with CO2 Regulation (the Carper Bill, S. 843)
- Economy-Wide Greenhouse Gas (GHG) Cap-and-Trade Program (the McCain-Lieberman amendment)

For each of these clean air and climate policy scenarios, the impacts on the company will depend on: (1) the stringency of the emissions reduction requirements; (2) the compliance deadlines; (3) the availability of emissions trading; and (4) if there is trading, the methodology for allocation of allowances. In addition, the assessment considered not only the impacts of different policy scenarios individually but also the impacts from the interaction of potential clean air policy scenarios with potential climate policy scenarios.

2. Clean Air Policy Scenarios

An important first step in assessing potential company impacts from clean air policy scenarios involves the identification of key Clean Air Act “regulatory drivers” that are likely to require future reductions of conventional pollutants from the electric power sector. Assessment of these regulatory drivers indicates a high probability that the company will be required to achieve substantial reductions in SO2, NOx, and mercury emissions from its coal-fired generating fleet over the next 10 to 15 years. The company will face such reduction requirements under each of the scenarios examined below, with the primary differences between the scenarios being related to the stringency, timing, and implementation of the reduction requirements.

Clean Air Policy Scenario #1: Current Administration Regulatory Policy

This scenario involves three components. The first and primary one is the integrated air regulatory program for controlling SO2, NOx, and mercury emissions from the electric generating units proposed by the Bush Administration. This “3-pollutant control program” first was proposed in the form of the Clear Skies legislation, but now is being pursued by the Administration in the form of EPA’s proposed utility Mercury Reduction and Clean Air Interstate (CAIR) rules, the latter of which would impose NOx and SO2 reduction obligations. The second component relates to the emissions control requirements that states might impose on the company’s generating units to address local non-attainment air quality
problems. The third component is pending New Source Review (NSR) litigation. Each of these components is briefly described below.

**Mercury and Transport Rulemakings**

**Reduction Levels and Compliance Deadlines:** The following table provides a brief summary of the reduction levels and compliance deadlines in EPA’s mercury and CAIR rulemakings:

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2015</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SO₂</strong></td>
<td>3.9 million ton cap</td>
<td>2.7 million ton cap</td>
<td>58% reduction</td>
</tr>
<tr>
<td></td>
<td>(58% reduction)</td>
<td>(71% reduction)</td>
<td></td>
</tr>
<tr>
<td><strong>NOₓ</strong></td>
<td>1.6 million ton cap</td>
<td>1.3 million ton cap</td>
<td>53% reduction</td>
</tr>
<tr>
<td></td>
<td>(53% reduction)</td>
<td>(65% reduction)</td>
<td></td>
</tr>
<tr>
<td><strong>Mercury</strong></td>
<td>“co-benefit” controls</td>
<td>15 ton cap</td>
<td>69% reduction</td>
</tr>
<tr>
<td></td>
<td>(± 34 tons cap)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(Reductions measured from 2002 levels.)

**Coordinated Compliance Deadlines:** The above timetable assumes that EPA finalizes its preferred mercury rulemaking option, a cap-and-trade program with a 2008 compliance deadline. Such coordination would allow the company to meet a substantial portion of its mercury emission reduction obligation as a “co-benefit” of installing control technologies to meet its SO₂ and NOₓ requirements under the CAIR.

**Geographic Scope:** Although the mercury control program applies nationwide, coverage of the transport rule is limited to the Eastern United States (28 states and the District of Columbia). Oklahoma is the only state not covered by the CAIR in which the company operates coal-fired power plants. EPA has requested comment on whether the CAIR should be extended to cover additional states in the West.

**Allowance Allocations:** The Clear Skies legislation contains specific formulas for allocating allowances to affected electric generating units. However, under the mercury and CAIR rulemakings, EPA lacks authority to impose rules for allocating allowances. The ultimate decisions on allocations must be left to the states, which could adopt allocation methodologies that would substantially increase the company’s costs of compliance, e.g., an output-based system, set-asides for new units, or an auction.

**Reform of Air Regulatory Programs:** The Clear Skies bill includes not only a 3-pollutant program but also a suite of revisions to the existing Clean Air Act. These revisions aim to eliminate duplicative and inconsistent control requirements (such as requirements for regional haze) and reform existing command-and-control programs (such as the NSR program). However, EPA does not have the authority to undertake such sweeping revisions to the Clean Air Act in its mercury and CAIR rulemakings.

Indeed, as discussed in Clean Air Policy Scenario #2, EPA may not even be able to provide “safe harbor” protection from petitions filed by “downwind” states seeking even more stringent interstate transport controls.

**State Regulatory Programs for Local Non-Attainment**

EPA modeling data suggest that emissions reductions resulting from the CAIR will not be sufficient for many states to attain the fine particulate matter (PM2.5) and 8-hour ozone standards. In such cases, states will need to develop local air quality strategies that require additional SO₂ and NOₓ reductions. For those states where the company owns or operates coal-fired generating units, a realistic possibility exists that the company’s generating units could become subject to additional and more prescriptive reduction requirements. For example, states might opt to accelerate control requirements...
imposed under the CAIR or limit the company’s flexibility to achieve compliance through emissions trading (i.e., by imposing facility-specific control requirements). These considerations should be factored into the company’s regulatory assessment in this and the other clean air policy scenarios.

NSR Litigation

The ongoing NSR litigation is a third area of great importance to the company and merits consideration in each clean air policy scenario. The settlements in other utility cases suggest that resolution of the company’s case could: (1) result in unit-specific control requirements that undermine the flexibility of the trading programs; (2) require surrender of allowances; and (3) place restrictions on the use or transfer of surplus allowances.

Clean Air Policy Scenario #2: Litigation and Piecemeal Implementation

Environmental groups and a number of states will challenge in court the Administration’s mercury and CAIR rules if promulgated in the form in which they have been proposed. Success in one or more of these legal challenges could diminish the flexibility and other benefits of the integrated 3-pollutant regulatory program significantly. It is difficult to assess litigation outcomes of these court challenges with any amount of precision given that EPA is still in the process of rulemaking.\(^3\)

Clean Air Policy Scenario #2 provides one example of how an unfavorable outcome on one or more litigation issues could affect the clean air policy framework under which the company might have to operate.

Earlier Compliance Deadlines for SO\(_2\) and NO\(_x\): Of critical importance to the company are the compliance deadlines for SO\(_2\) and NO\(_x\) under the CAIR. As discussed above, EPA has proposed to establish a phase-one deadline of 2010 and a phase-two deadline of 2015.\(^4\) Although this is already an ambitious compliance schedule, there is a significant risk that the 2010/2015 deadlines may be accelerated further, for the following reasons.

First, EPA may not be able to defend the validity of the proposed 2010/2015 compliance deadlines. Recall that the aim of the CAIR is to aid states in attaining the PM2.5 and 8-hour ozone air quality standards by reducing interstate transport of SO\(_2\) and NO\(_x\) emissions, which are precursors to PM2.5 and ozone. However, the 2010/2015 compliance deadlines do not conform to the dates by which states must achieve the SO\(_2\) and NO\(_x\) reductions necessary for attaining the PM2.5 standard. The Clean Air Act mandates a 2010 attainment deadline for the standard; EPA is permitted to extend the deadline to 2015 under particular circumstances. States with an attainment deadline of 2010 might assert that implementation of controls on upwind transport by 2015 will not do enough. A similar problem also exists for states with an attainment deadline of 2015 because compliance with the PM2.5 standard is measured in terms of a 3-year average (2013, 2014, and 2015). These states could argue that upwind reductions achieved by 2015 will come too

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\(^1\) Ohio, for instance, is one state with four counties that are modeled to remain in non-attainment for the PM2.5 standard after implementation of EPA's transport rule in 2015.

\(^2\) EPA expects to list 99 counties through the Eastern U.S. as not attaining the PM2.5 and 8-hour ozone standards. Many of these counties are located in states — such as Ohio, Indiana, West Virginia, Kentucky, and Texas — where the company owns or operates coal-fired generating units.

\(^3\) Comments on the legal vulnerability address the specific elements of regulatory proposals that were published in the Federal Register on January 30, 2004.

\(^4\) Note that the latter deadline of 2015 falls three years earlier than the deadline for NO\(_x\) and SO\(_2\) limits that would apply under the Clear Skies legislation (2018).
late to help them demonstrate attainment with the PM2.5 standard during the 2013 – 2015 compliance period. Although it is difficult to predict how a court would handle this potential mismatch between transport rule compliance deadlines and attainment dates, there is some risk that EPA would be unable to defend the proposed 2010/2015 timetable.

Even if EPA is able to sustain the 2010/2015 timetable in the final CAIR, some states might use section 126 of the Clean Air Act to petition for an expedited schedule of reductions. That section establishes a regulatory mechanism to remedy interstate transport that is separate and distinct from the one used for the CAIR. Pursuant to section 126, a state may petition EPA for a finding that an “upwind” state is “significantly contributing” to nonattainment problems in the petitioning state. If EPA affirms such a petition, emitting sources in the upwind state must implement controls within no more than 3 years of the EPA finding. Thus, depending on when EPA finalizes the CAIR, successful section 126 petitions could move the NOx and SO2 compliance deadlines up to as early as 2008 or 2009. North Carolina already has filed such a petition.

More Onerous Mercury Controls: EPA has proposed three separate regulatory options for controlling mercury emissions from coal-fired electric generating units. One option involves setting unit-specific standards based on “maximum available control technology” (MACT). Either of the other two options would establish a “cap-and-trade” program without any unit-specific control requirements for existing units. EPA’s preferred option is to implement the reductions through a model cap-and-trade program adopted by states. The discussion below briefly identifies the potential regulatory outcomes of importance to the company if a court were to reverse an EPA decision to adopt its preferred cap-and-trade approach.

No Emissions Trading: Substantial legal questions exist as to EPA’s authority to avoid the MACT regulatory process and then to adopt an alternative trading option. An adverse court ruling on either one of these issues would lead to inflexible unit-specific controls, with only a possibility of emissions averaging among units located at the same facility.

Increased Stringency of Near-Term Controls: The company would likely become subject to more stringent reduction levels if a court were to invalidate a final rule adopting a mercury cap-and-trade program and direct EPA to adopt unit-specific MACT standards instead. One reason for the increased stringency would be EPA’s legal obligation to set those standards in accordance with the highly prescriptive MACT standard-setting process. Another reason would be the probability of anticipated advances in dedicated mercury control technologies that may have occurred in the intervening years.

A third area of major concern for the company has been the potential for uncoordinated compliance deadlines for mercury, SO2, and NOx controls to be imposed under the mercury and CAIR rules. A compliance deadline that is earlier than the deadline for SO2 and NOx reductions would require installation of costly dedicated mercury controls at a significant amount of the company’s coal-fired generation capacity (assuming such technologies are proven and commercially available). Such an outcome would occur only under the following circumstances: EPA (1) adopts the mercury MACT option (which has a 2008 compliance deadline), of its preferred cap-and-trade options (which each have instead of one a 2010 compliance deadline), and then

5 Furthermore, the installation of these mercury controls would be in addition to the construction of scrubbers and SCR systems that are necessary to meet the company’s SO2 and NOx obligations.
(2) successfully defends the final MACT rule against legal challenges, including those relating to the stringency of the control requirements. Although not impossible, the likelihood of this occurring appears to be low.\(^6\)

**Clean Air Policy Scenario #3: Governmental Policy Change**

A change in Administration could result in the Executive Branch pursuing air regulatory policies more stringent than those discussed under *Clean Air Policy Scenario #1*. The current Administration could also modify specific aspects of its current regulatory policies in response to litigation outcomes or a range of other factors. This scenario provides an example of how such changes in policy might affect future development of the pending 3-pollutant control program in both the regulatory and legislative contexts.

**Regulatory Context:** A significant shift in air regulatory policies could occur with a change in Administration. Even if EPA succeeds in issuing final regulations on a significant portion of its 3-pollutant regulatory program by the end of this year, court challenges could suspend the program’s legal effect for some time, providing a potential opportunity for modifications by a new Administration. Examples of the policy changes that a new Administration might pursue include the following:

- **Increase the stringency of the mercury control levels:** It is plausible that a new Administration would be responsive to states and environmental groups that have proposed 80-to-90 percent reduction levels nationwide.

- **Increase the stringency of the SO\(_2\) and NO\(_x\) control levels:** A new Administration might propose reduction levels approaching 75 percent, particularly in the case of SO\(_2\).

- **Eliminate or restrict mercury emissions trading:** A new Administration could pull back from the cap-and-trade approach proposed in the pending mercury rulemaking. Although imposition of unit-specific MACT standards is a possibility, other alternatives to nationwide trading might be considered.

- **Accelerate compliance deadlines:** A strong possibility exists that a new Administration would accelerate the compliance deadlines in the rules. One plausible example would be to require compliance with phase-one reductions by 2008 and phase-two reductions (for SO\(_2\) and NO\(_x\)) by 2013.

**Legislative Context:** A new Administration might have several reasons to advocate adoption of multi-pollutant legislation instead of implementing a multi-pollutant program through rulemakings. Legislation would avoid protracted litigation. In addition, as noted in *Climate Policy Scenario #2*, adoption of multi-pollutant control legislation would provide an opportunity to pursue mandatory CO\(_2\) limits on the electric power sector.

Generally speaking, any legislation advanced by the new Administration would reflect the policy positions described above in *Clean Air Policy Scenario #2*, i.e., increased stringency of control levels, limited or no

\(^6\) In contrast, the possibility of uncoordinated compliance deadlines appears to be eliminated under any of the more probable regulatory outcomes that assume that EPA adopts a mercury cap-and-trade program. If, on the one hand, EPA is able to defend successfully the cap-and-trade program in litigation, the 2010 compliance deadline of the program would allow the company to take advantage of the co-benefit mercury reductions achievable through NO\(_x\) and SO\(_2\) controls required by the CAIR. If, on the other hand, EPA were unsuccessful in defending the cap-and-trade program, the mercury compliance deadline would be extended until at least 2010 because of the litigation and ensuing EPA rulemaking to promulgate MACT standards.
emissions trading for mercury, and accelerated compliance deadlines.

One example of a legislative proposal that is consistent with policy changes described in this scenario is Senator Carper’s Clean Air Planning Act of 2003 (S. 843). As compared to Clear Skies, the Carper bill proposes to accelerate the compliance deadlines and/or make more stringent the SO2, NOx, and mercury control requirements. In addition, the bill would impose minimum unit-specific control requirements for mercury that would likely limit the compliance flexibility of the emissions trading program established for that pollutant. Finally, the bill contains detailed allowance allocation methodologies that establish special reserves for new units and distribute allowances based on generation output.

3. Climate Change Policy Scenarios

Three climate change policy scenarios for the next 20 years have been identified and examined, each of which have varying levels of probability of becoming reality. Climate Policy Scenario #1 would reflect continuation of the current state of climate policy, i.e., a non-regulatory approach at the federal level, to which some states are reacting by implementing GHG regulatory programs. Climate Policy Scenarios #2 and #3 reflect regulatory approaches at the federal level — each is modeled after legislation that has been introduced in Congress and that has garnered not insignificant bipartisan support.

In assessing the potential impacts on the company of any climate policy program involving GHG trading, the methodology adopted for allocating allowances will be critical (i.e., through an auction, based on historical emissions, based on output, or other approaches). Note that if the climate program’s allocation approach is based on historical emissions, an additional issue in assessing the company’s near-term GHG mitigation strategies is the program’s treatment of baselines.

Climate Policy Scenario #1:
Federal Voluntary Policy; Regulatory Programs in Certain States

The Bush Administration has developed a suite of non-regulatory climate policies consisting of a national goal of reduced emissions intensity, voluntary pledges by major sectors to implement mitigation activities, and funding for increased research and development. A number of states, particularly in the Northeast and on the West Coast, have responded by developing regulatory GHG reduction programs and/or renewable portfolio standards (RPS). Climate Policy Scenario #1 assumes a continuation of this state of affairs and consists of the following policy elements:

- The federal government retains the Bush Administration’s national emissions goal of reducing the GHG intensity of the U.S. economy (GHG emissions/per unit GDP) by 18 percent by 2012.
  - The federal government undertakes a progress review in 2012 to determine whether other measures are needed.

- The federal government retains the Climate VISION program, which consists of agreements with sectors or trade associations to promote voluntary mitigation activity.
  - Under the federal government’s agreement with the power sector, the industry collectively commits to facilitate actions by utility companies to reduce the sector’s GHG emission intensity by an equivalent of 3 to 5 percent below 2000 – 2002 baseline levels, as measured over the 2010 – 2012 period.

- The federal government continues to fund a range of technology development and research initiatives.

- The ten Northeastern states involved in the “Regional Greenhouse Gas Initiative” establish a regional cap-and-trade program of modest stringency for electric utilities by the beginning of 2005. Other states move forward with GHG regulatory programs and/or RPS programs.
Climate Policy Scenario #2: Multi-Emissions Program with CO\textsubscript{2} Regulation

As discussed above, one of the reasons that the Bush Administration has not been able to secure passage of its Clear Skies legislation in Congress is the insistence by Democrats and some Republicans that any multi-emissions program affecting utilities should include regulation of power plant emissions of CO\textsubscript{2}. One such alternative multi-emissions program, which has attracted some interest in Congress, is the Carper Bill (S. 843). Climate Policy Scenario #2 combines regulation of utility CO\textsubscript{2} emissions with an integrated regulatory program for conventional pollutants in a multi-emissions program along the lines of the Carper Bill. Such a program consists of the following climate policy elements:

- The program has an annual emissions cap equal to the year 2006 level of CO\textsubscript{2} emissions for the power sector, which applies in the sixth through ninth years after enactment.
- In the tenth year through twentieth years after enactment, the annual emissions cap declines to the year 2001 level of CO\textsubscript{2} emissions for the sector.
- The program applies to all fossil fuel-fired electricity generating units greater than 25 MW (including cogeneration). Covered units must submit allowances to cover their emissions starting in the sixth year after enactment.
- EPA promulgates regulations for allocation of CO\textsubscript{2} allowances equal to the cap. The program requires those regulations to provide for allocations to existing fossil fuel-fired units and existing renewable units (including hydro). EPA also is required to allocate allowances to nuclear units on the basis of any incremental increase in generation at such units since 1990. Finally, EPA is required to establish a reserve of allowances for new units, to be determined on the basis of projections of electricity generation.
- Each unit’s allocation is based on its pro rata share of total electricity generation (measured as the annual average of the three years preceding enactment).
- Banking of allowances is permitted under the program, but borrowing from future allocations is prohibited.
- Additional allowances beyond the level of the cap can be created through development of GHG mitigation projects certified by an independent board and through submission of allowances from other U.S. or international climate programs. A limited portion of allowances also are available for mitigation projects implemented before the sixth year after enactment — no more than the equivalent of 10 percent of the cap that applies in the sixth through ninth years after enactment.

Climate Policy Scenario #3: Economy-Wide GHG Cap-and-Trade Program

In October 2003, the Senate considered a climate change amendment sponsored by Sens. McCain and Lieberman and rejected it by a vote of 55 – 43. A number of Republican Senators voted in favor of the bill. Scenario #3 involves adoption of a program modeled after the McCain-Lieberman amendment, which consists of the following climate policy elements:

- The program establishes an annual emissions cap for the electricity generation, industrial, commercial, and transportation sectors. The cap is set at year-2000 levels and must be met in 2010.
- The cap covers emissions of CO\textsubscript{2}, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF\textsubscript{6}).
- The cap applies to any entities within the four sectors that emits more than 10,000 metric tons of CO\textsubscript{2}-equiva-
lent GHG emissions annually. Starting in 2010, covered entities in the electricity generation, industrial, and commercial sector must submit allowances equal to their emissions. Covered entities in the transportation sector must submit allowances equal to the emissions associated with the petroleum products they sell for transportation uses. Producers of HFCs, PFCs, and SF6 must submit allowances for every ton of those gases that they produce or import and that will ultimately be emitted in the United States.

- Some portion of total allowances available is set aside for early action. The program would allocate these allowances to entities that register GHG mitigation projects implemented before 2010.
- With regard to allowances not allocated for early action, the Secretary of Commerce must determine what portion is allocated to the covered sectors and what portion is allocated to a “Climate Change Credit Corporation,” which has the obligation to sell its portion and use the proceeds to reduce costs borne by consumers and workers. The Secretary of Commerce must base his sectoral allocations on an assessment of potential impacts, including impacts of the allocations on household income, corporate income, economic efficiency, and competitiveness.
- Once the Secretary of Commerce has determined sectoral allocations, the EPA Administrator determines intrasectoral allocations to individual entities. EPA’s allocation process must: (1) encourage energy efficiency; (2) minimize administrative costs; (3) not penalize entities that registered early emission reductions; and (4) provide sufficient allocations for new entrants into the sector.
- A covered entity may satisfy 15 percent of its total allowance submission requirements through the following “alternative compliance measures:
  - The entity may submit allowances from other countries that have enforceable GHG emission limitations.
  - The entity may earn allowances by implementing a project that generates net increases in sequestration. The project must be approved by the government and registered in a National GHG Database to be established under the program.
  - The entity may earn allowances by registering GHG reductions implemented by non-covered entities.
  - The entity may borrow allowances that otherwise would be allocated to the entity in future years. The availability of such borrowing is very limited.

- The program permits banking of allowances.

This assessment considered both immediate (2004) and delayed (2009) passage of these policies, in order to evaluate the impacts of the timing of such climate policies on investments to address currently regulated emissions. In both cases, it was assumed for analytical purposes that implementation of the McCain-Lieberman greenhouse gas policies would follow five years after passage.

4. Excerpts from 2003 10-K Filing

The Current Air Quality Regulatory Framework

The Clean Air Act (CAA) is the legislation that establishes the federal regulatory authority and oversight for emissions from our fossil-fired generating plants. The states, with oversight and approval from the Federal EPA, administer and enforce these laws and related regulations.

Title I of the CAA

National Ambient Air Quality Standards: The Federal EPA periodically reviews the available scientific data for six pollutants and establishes a standard for concentration levels in ambient air for these substances to protect the public welfare and public health with an extra margin for safety. These requirements are known as “national ambient air quality standards” (NAAQS).

The states identify those areas within their state
that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). States must develop their individual state implementation plans (SIPs) with the intention of bringing non-attainment areas into compliance with the NAAQS. In developing a SIP each state must allow attainment areas to maintain compliance with the NAAQS. This is accomplished by controlling sources that emit one or more pollutants or precursors to those pollutants. The Federal EPA approves SIPs if they meet the minimum criteria in the CAA. Alternatively, the Federal EPA may prescribe a federal implementation plan if they conclude that a SIP is deficient. Additionally, the Federal EPA can impose sanctions, up to and including withholding of federal highway funds, in states that fail to submit an adequate SIP or a SIP that fails to bring non-attainment areas into NAAQS compliance within the time prescribed by the CAA.

The CAA also establishes visibility goals, which are known as the regional haze program, for certain federally designated areas, including national parks. States are required to develop and submit SIP provisions that will demonstrate reasonable progress toward preventing the impairment and remedying any existing impairment of visibility in these federally designated areas.

Each state’s SIP must include requirements to control sources that emit pollutants in that state as well as requirements to control sources that significantly contribute to non-attainment areas in other state. If a state believes that its air quality is impacted by upwind sources outside their borders, that state can submit a petition that asks the Federal EPA to impose control requirements on specific sources in other states if those states’ SIPs do not contain adequate requirements to control those sources. For example, the Federal EPA issued a NOx Rule in 1997, which affected 22 eastern states (including states in which AEP operates) and the District of Columbia. The NOx Rule asked these 23 jurisdictions to adopt requirements, for utility and industrial boilers and certain other emission sources, to employ cost-effective control technologies to reduce NOx emissions. The purpose of the request was to allow certain eastern states to reduce the contribution from these 23 jurisdictions to ozone non-attainment areas in certain eastern states.

The Federal EPA also granted four petitions filed by certain eastern states seeking essentially the same levels of control on emission sources outside of their states and issued a Section 126 Rule. All of the states in which we operate that were subject to the NOx Rule have submitted the required SIP revisions. In response, the Federal EPA issued the NOx Rule and the Section 126 Rule, which are discussed below.

The compliance date for the NOx Rule is May 31, 2004. In 2000, the Federal EPA also adopted a revised Section 126 Rule which granted petitions filed by four northeastern states. The revised Section 126 Rule imposes emissions reduction requirements comparable to the NOx Rule also beginning May 31, 2004, for most of our coal-fired generating units.

In 2000, the Texas Commission on Environmental Quality adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance requirements began in May 2003 for TCC and begin in May 2005 for SWEPCo.

We are installing a variety of emission control technologies to improve NOx emissions standards and to comply with applicable state and federal NOx requirements. These include selective catalytic reduction (SCR) technology on certain units and other combustion control technologies on a larger number of units.

AEP’s electric utility units are currently subject to SIP requirements that control SOx and particulate matter emissions in all states, and that control NOx emissions in certain states. Our generating plants
comply with applicable SIP limits for SO₂, NOₓ and particulate matter.

Hazardous Air Pollutants: In 1990 Amendments to the CAA, Congress required the Federal EPA to identify the sources of 188 hazardous air pollutants (HAPs) and to develop regulations that prescribe a level of HAP emission reduction. These reductions must reflect the application of maximum achievable control technology (MACT). Congress also directed the Federal EPA to investigate HAP emissions from the electric utility sector and to submit a report to Congress. The Federal EPA’s 1998 report to Congress identified mercury emissions from coal-fired electric utility units and nickel emissions from oil-fired utility units as sources of HAP emissions that warranted further investigation and possible control.

New Source Performance Standards and New Source Review: The Federal EPA establishes New Source Performance Standards (NSPS) for 28 categories of major stationary emission sources that reflect the best demonstrated level of pollution control. Sources that are constructed or modified after the effective date of an NSPS standard are required to meet those limitations. For example, many electric utility units are regulated under the NSPS for SO₂, NOₓ, and particulate matter. Similarly, each SIP must include regulations that require new sources, and major modifications at existing emission sources that result in a significant net increase in emissions, to submit a permit application and undergo a review of available technologies to control emissions of pollutants. These rules are called new source review (NSR) requirements.

Different NSR requirements apply in attainment and non-attainment areas.

In attainment areas:
- An air quality review must be performed, and
- The best available control technology must be employed to reduce new emissions.

In non-attainment areas:
- Requirements reflecting the lowest achievable emission rate are applied to new or modified sources, and
- All new emissions must be offset by reductions in emissions of the same pollutant from other sources within the same control area.

Neither the NSPS nor NSR requirements apply to certain activities, including routine maintenance, repair or replacement, changes in fuels or raw materials that a source is capable of accommodating, the installation of a pollution control project, and other specifically excluded activities.

Title IV of the CAA (Acid Rain)
The 1990 Amendments to the CAA included a market-based emission reduction program designed to reduce the amount of SO₂ emitted from electric utility units by approximately 50 percent from 1980 levels. This program also established a nationwide cap on utility SO₂ emissions of 8.9 million tons per year. The Federal EPA administers its SO₂ program through an allowance allocation and trading system. Allowances are allocated to specific units based on statutory formulas. Annually each utility unit must surrender one allowance for each ton of SO₂ that it emits. Emission sources that install controls and no longer need all of their allowances can bank those allowances for future use or trade them to other emission sources.

Title IV also contains requirements for utility sources to reduce NOₓ emissions through the use of available combustion controls. Units must meet NOₓ emission rates standards which are specific to that unit.
Future Reduction Requirements for SO₂, NOₓ, and Mercury

In 1997, the Federal EPA adopted new, more stringent NAAQS for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA has identified SO₂ and NOₓ emissions as precursors to the formation of fine particulate matter. NOₓ emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NOₓ and SO₂ from our generating units are highly probable. In addition, the Federal EPA has proposed a set of options for future mercury controls at coal-fired power plants.

Multi-emission control legislation, known as the Clear Skies Act, was introduced in Congress and is supported by the Bush Administration. This legislation would regulate NOₓ, SO₂, and mercury emissions from electric generating plants. We support enactment of this comprehensive, multi-emission legislation so that compliance planning can be coordinated and collateral emission reductions maximized. We believe the Bush Administration’s Clear Skies Act would establish stringent emission reduction targets and achievable compliance timetables utilizing a cost-effective nationwide cap and trade program. Although the prospects for enactment of the Clear Skies Act are low, there are alternative regulatory approaches which will likely require us to substantially reduce SO₂, NOₓ and mercury emissions over the next ten years.

Regulatory Emissions Reductions

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% in emissions of SO₂, NOₓ and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

- The Federal EPA proposed an interstate air quality rule for reducing SO₂ and NOₓ emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone NAAQS. These reductions could also satisfy these states’ obligations to make reasonable progress towards the national visibility goal under the regional haze program.
- The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.

The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NOₓ and SO₂ emissions from coal-fired electric utility units. SO₂ and NOₓ emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO₂ emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NOₓ emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO₂ and NOₓ trading programs have not yet been proposed.

To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of MACT on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO₂ (scrubbers) and...
NOx (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO₂ and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, that can be used to comply with the more stringent SO₂ and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018.

The Federal EPA’s proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO₂, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

Estimated Air Quality Environmental Investments
Each of the current and possible future environmental compliance requirements discussed above will require us to make significant additional investments, some of which are estimable. The proposed rules discussed above have not been adopted, will be subject to further revision, and will be the subject of a court challenge and further modifications.

All of our estimates are subject to significant uncertainties about the outcome of several interrelated assumptions and variables, including:
• Timing of implementation
• Required levels of reductions
• Allocation requirements of the new rules, and
• Our selected compliance alternatives.

As a result, we cannot estimate our compliance costs with certainty, and the actual costs to comply could differ significantly from the estimates discussed below.

All of the costs discussed below are incremental to our current investment base and operating cost structure. These expenditures for pollution control technologies, replacement generation and associated operating costs are recoverable from customers through regulated rates (in regulated jurisdictions) and should be recoverable through market prices (in deregulated jurisdictions). If not, those costs could adversely affect
Estimated Investments for NOx Compliance
We estimate that we will make future investments of approximately $600 million to comply with the Federal EPA’s NOx Rule, the Texas Commission on Environmental Quality Rule and other final Federal EPA NOx-related requirements. Approximately $500 million of these investments are reflected in our estimated construction expenditures for 2004 – 2006. As of December 31, 2003, we have invested approximately $1.1 billion to comply with various NOx requirements.

Estimated Investments for SO\textsubscript{2} Compliance
We are complying with Title IV SO\textsubscript{2} requirements by installing scrubbers, other controls and fuel switching at certain generating units. We also use SO\textsubscript{2} allowances that we:

- Receive in the annual allowance allocation by the Federal EPA,
- Obtain through participation in the annual allowance auction,
- Purchase in the allowance market, and
- Obtained as bonus allowances for installing controls early.

Decreasing SO\textsubscript{2} allowance allocations, a diminishing SO\textsubscript{2} allowance bank, and increasing allowance prices in the market will require us to install additional controls on certain of our generating units. We plan to install 3,500 MW of additional scrubbers over the next 4 years to comply with our Title IV SO\textsubscript{2} obligations. In total we estimate these additional capital costs to be approximately $1.2 billion. Of this total, we estimate that $900 million will be expended during 2004 – 2006 and this amount is included in our total estimated construction expenditures for 2004 – 2006.

Estimated Investments to Comply with Future Reduction Requirements
Our planning assumptions for the levels and timing of emissions reductions parallel the reduction levels and implementation time periods stated in the proposed rules issued by the Federal EPA in January 2004. We have also assumed that the Federal EPA will implement a mercury trading option and will design its proposed cap and trade mechanism for SO\textsubscript{2}, NOx and mercury emissions in a manner similar to existing cap and trade programs. Based on these assumptions, compliance would require additional capital investment of approximately $1.7 billion by 2010, the end of the first phase for each proposed rule. We also estimate that we would incur increases in variable operation and maintenance expenses of $150 million for the periods by 2010, due to the costs associated with the maintenance of additional control systems, disposal of scrubber by-products and the purchase of reagents. We estimate that we will invest $200 million of this amount through 2006, and this amount is included in our total estimated construction expenditures for 2004 – 2006.

If the Federal EPA’s preferred mercury trading option is not implemented, then any alternative mercury control program requiring adherence to MACT standards would also have implementation costs that could be significant. We cannot currently estimate the nature or amount of these costs. Furthermore, scrubber and SCR technologies could not be deployed at every bituminous-fired plant that AEP operates within the three-year compliance schedule provided under the proposed MACT rule. These MACT compliance costs, which we are not able to estimate, would be incremental to other cost estimates that we have discussed above.

Beyond 2010, we expect to incur additional costs for pollution control technology retrofits and associated operation and maintenance of the equipment. We cannot
estimate these additional costs because of the uncertainties associated with the final control requirements and our associated compliance strategy, but these capital and operating costs will be significant.

New Source Review Litigation
Under the CAA, if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the NSRs of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at our generating units over a 20-year period.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.

Superfund and State Remediation
By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, PCBs and other hazardous and non-hazardous materials. We are currently incurring costs to safely dispose of these substances.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized the Federal EPA to administer the clean-up programs. As of year-end 2003, subsidiaries of AEP are named by the Federal EPA as a PRP for five sites. There are six additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at six sites under state law. Liability has been resolved for a number of sites with no significant effect on results of operations.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. Therefore, our present...
estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs were attributed to our subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be included in our electricity prices.

Global Climate Change
At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997, more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly CO\textsubscript{2}, which many scientists believe are contributing to global climate change. The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001, President Bush announced his opposition to the treaty. Ratification of the treaty by a majority of the countries’ legislative bodies is required for it to be enforceable. Enforceability of the protocol is now contingent on ratification by Russia, which has expressed concerns about doing so.

On August 28, 2003, the Federal EPA issued a decision in response to a petition for rulemaking seeking reductions of CO\textsubscript{2} and other greenhouse gas emissions from mobile sources. The Federal EPA denied the petition and issued a memorandum stating that it does not have the authority under the Clean Air Act to regulate CO\textsubscript{2} or other greenhouse gas emissions that may affect global warming trends. The Circuit Court of Appeals for the District of Columbia is reviewing these actions.

We do not support the Kyoto Protocol but have been working with the Bush Administration on a voluntary program aimed at meeting the President’s goal of reducing the greenhouse gas intensity of the economy by 18% by 2012. For many years, we have been a leader in pursuing voluntary actions to control greenhouse gas emissions. We expanded our commitment in this area in 2002 by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which we are obligated to reduce or offset 18 million tons of CO\textsubscript{2} emissions during 2003 – 2006.

We acquired 4,000 MW of coal-fired generation in the United Kingdom in December 2001. These assets may have future CO\textsubscript{2} emission control obligations beginning in 2005. We plan to dispose of our investment in this generation during 2004.

5. Excerpt from 2004 1st Quarter 10-Q Filing
This discussion updates certain events occurring in 2004 and adds an estimate of future capital expenditures for the Clean Water Act rule. You should also read the “Significant Factors — Environmental Matters” section within Management’s Financial Discussion and Analysis of Results of Operations in our 2003 Annual Report for a complete description of all material environmental matters affecting us, including, but not limited to, (1) the current air quality regulatory framework, (2) estimated air quality environmental investments, (3) superfund and state remediation, (4) global climate change, and (5) costs for spent nuclear fuel and decommissioning.

Future Reduction Requirements for SO\textsubscript{2}, NO\textsubscript{x}, and Mercury
In 1997, the Federal EPA adopted new, more stringent national ambient air quality standards for fine particulate matter and ground-level ozone. The Federal EPA is in the process of developing final designations for fine particulate matter and ground-level ozone non-attainment areas. The Federal EPA finalized designations for ozone non-attainment areas on April 15, 2004. On the same day, the Administrator of the Federal EPA signed a final
rule establishing the elements that must be included in state implementation plans (SIPs) to achieve the new standards, and setting deadlines ranging from 2008 to 2015 for achieving compliance with the final standard, based on the severity of non-attainment. All or parts of 474 counties are affected by this new rule, including many urban areas in the Eastern United States.

The Federal EPA identified SO\textsubscript{2} and NO\textsubscript{x} emissions as precursors to the formation of fine particulate matter. NO\textsubscript{x} emissions are also identified as a precursor to the formation of ground-level ozone. As a result, requirements for future reductions in emissions of NO\textsubscript{x} and SO\textsubscript{2} from our generating units are highly probable. In addition, the Federal EPA proposed a set of options for future mercury controls at coal-fired power plants.

**Regulatory Emissions Reductions**

On January 30, 2004, the Federal EPA published two proposed rules that would collectively require reductions of approximately 70% each in emissions of SO\textsubscript{2}, NO\textsubscript{x} and mercury from coal-fired electric generating units by 2015 (2018 for mercury). This initiative has two major components:

1. **The Federal EPA proposed an interstate air quality rule for reducing SO\textsubscript{2} and NO\textsubscript{x} emissions across the eastern half of the United States (29 states and the District of Columbia) to address attainment of the fine particulate matter and ground-level ozone national ambient air quality standards. These reductions could also satisfy these states’ obligations to make reasonable progress towards the national visibility goal under the regional haze program.**

2. **The Federal EPA proposed to regulate mercury emissions from coal-fired electric generating units.**

   The interstate air quality rule would require affected states to include, in their SIPs, a program to reduce NO\textsubscript{x} and SO\textsubscript{2} emissions from coal-fired electric util-

   ity units. SO\textsubscript{2} and NO\textsubscript{x} emissions would be reduced in two phases, which would be implemented through a cap-and-trade program. Regional SO\textsubscript{2} emissions would be reduced to 3.9 million tons by 2010 and to 2.7 million tons by 2015. Regional NO\textsubscript{x} emissions would be reduced to 1.6 million tons by 2010 and to 1.3 million tons by 2015. Rules to implement the SO\textsubscript{2} and NO\textsubscript{x} trading programs have not yet been proposed.

   On April 15, 2004, the Federal EPA Administrator signed a proposed rule detailing how states should analyze and include “Best Available Retrofit” requirements for individual facilities in their SIPs to address regional haze. The guidance applies to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain regulated pollutants in specific industrial categories, including utility boilers. The Federal EPA included an alternative “Best Available Retrofit” program based on emissions budgeting and trading programs. For utility units that are affected by the January 24, 2004 Interstate Air Quality Rule (IAQR), described above, the Federal EPA proposed that participation in the trading program under the IAQR would satisfy any applicable “Best Available Retrofit” requirements.

   To control and reduce mercury emissions, the Federal EPA published two alternative proposals. The first option requires the installation of maximum achievable control technology (MACT) on a site-specific basis. Mercury emissions would be reduced from 48 tons to approximately 34 tons by 2008. The Federal EPA believes, and the industry concurs, that there are no commercially available mercury control technologies in the marketplace today that can achieve the MACT standards for bituminous coals, but certain units have achieved comparable levels of mercury reduction by installing conventional SO\textsubscript{2} (scrubbers) and NO\textsubscript{x} (SCR) emission reduction technologies. The proposed rule imposes significantly less stringent standards on generating plants that
burn sub-bituminous coal or lignite, which standards potentially could be met without installation of mercury control technologies.

The Federal EPA recommends, and we support, a second mercury emission reduction option. The second option would permit mercury emission reductions to be achieved from existing sources through a national cap-and-trade approach. The cap-and-trade approach would include a two-phase mercury reduction program for coal-fired utilities. This approach would coordinate the reduction requirements for mercury with the SO2 and NOx reduction requirements imposed on the same sources under the proposed interstate air quality rule. Coordination is significantly more cost-effective because technologies like scrubbers and SCRs, which can be used to comply with the more stringent SO2 and NOx requirements, have also proven highly effective in reducing mercury emissions on certain coal-fired units that burn bituminous coal. The second option contemplates reducing mercury emissions from 48 million tons to 34 million tons by 2010 and to 15 million tons by 2018. A supplemental proposal including unit-specific allocations and a framework for the emissions budgeting and trading program preferred by the Federal EPA was published in the Federal Register on March 16, 2004. Comments on both the initial proposal and the supplemental notice are due on or before June 29, 2004.

The Federal EPA’s proposals are the beginning of a lengthy rulemaking process, which will involve supplemental proposals on many details of the new regulatory programs, written comments and public hearings, issuance of final rules, and potential litigation. In addition, states have substantial discretion in developing their rules to implement cap-and-trade programs, and will have 18 months after publication of the notice of final rulemaking to submit their revised SIPs. As a result, the ultimate requirements may not be known for several years and may depart significantly from the original proposed rules described here.

While uncertainty remains as to whether future emission reduction requirements will result from new legislation or regulation, it is certain under either outcome that we will invest in additional conventional pollution control technology on a major portion of our fleet of coal-fired power plants. Finalization of new requirements for further SO2, NOx and/or mercury emission reductions will result in the installation of additional scrubbers, SCR systems and/or the installation of emerging technologies for mercury control.

**New Source Review Litigation**

Under the Clean Air Act (CAA), if a plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

The Federal EPA and a number of states have alleged APCo, CSPCo, I&M, OPCo and other unaffiliated utilities modified certain units at coal-fired generating plants in violation of the new source review requirements of the CAA. The Federal EPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The court also consolidated a separate lawsuit, initiated by certain special interest groups, with the Federal EPA case. The alleged modifications relate to costs that were incurred at our generating units over a 20-year period.

We are unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the CAA proceedings. We are also unable to predict the
timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do not prevail, any capital and operating costs of additional pollution control equipment that may be required, as well as any penalties imposed, would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates and market prices for electricity.
Annex D: Generation Technologies
Options, Prospects, and Implications for New Generating Technologies

Presentation to the Policy Committee of the AEP Board of Directors

May 25, 2004
Generating Technology Options

<table>
<thead>
<tr>
<th></th>
<th>PC Subcritical</th>
<th>PC Supercritical</th>
<th>CFB</th>
<th>NGCC</th>
<th>IGCC</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPC Cost, $/kW</td>
<td>1,250</td>
<td>1,300</td>
<td>1,300</td>
<td>440</td>
<td>1,300</td>
</tr>
<tr>
<td>Ave. Heat Rate, Btu/kWh</td>
<td>9,300</td>
<td>8,700</td>
<td>9,800</td>
<td>7,200</td>
<td>8,650</td>
</tr>
<tr>
<td>Cost of Electricity $/MWh</td>
<td>53</td>
<td>53</td>
<td>54</td>
<td>52</td>
<td>55</td>
</tr>
</tbody>
</table>

Source: EPRI estimates

Source Alstom Power

Pulverized Coal (PC) Plants

**Take away:** PC is the least-cost option for new coal plants when the cost of CO₂ removal is not considered.
Generating Technology Options

<table>
<thead>
<tr>
<th></th>
<th>PC Subcritical</th>
<th>PC Supercritical</th>
<th>CFB</th>
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<td>54</td>
<td>52</td>
<td>55</td>
</tr>
</tbody>
</table>

Source: EPRI estimates

Circulating Fluidized Bed (CFB) Plants

Source: US Department of Energy

Take away CFB is the technology of choice for low-BTU coals such as lignite. CFB technology does not currently provide better options for CO$_2$ removal.
Generating Technology Options

NGCC (Natural Gas Combined Cycle) Plants

<table>
<thead>
<tr>
<th></th>
<th>PC Subcritical</th>
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<td>53</td>
<td>53</td>
<td>54</td>
<td>52</td>
<td>55</td>
</tr>
</tbody>
</table>

Source: EPRI estimates

Source EPRI

Take away: NGCC is currently the least-cost option and allows the most MWs for the least capital at risk, but their dispatch depends on gas price; the average capacity factor of NGCC plants in 2003 was about 25%.
Generating Technology Options

<table>
<thead>
<tr>
<th>Source: EPRI estimates</th>
</tr>
</thead>
</table>

<table>
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<tr>
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<td>53</td>
<td>54</td>
<td>52</td>
<td>55</td>
</tr>
</tbody>
</table>

Source: US Department of Energy

Integrated Gasification Combined Cycle (IGCC) Plants

*Take away:* EPRI studies are indicating that IGCC Plant costs are approaching those of conventional technologies; this is yet to be tested in the marketplace with real contracts.
IGCC – The Good, the Bad, and the Ugly

• The good
  – Superior efficiency on Eastern Bituminous Coal
  – Superior environmental performance
  – Flexible byproduct processing
    • Tri-generation opportunities
    • Hydrogen production
  – Conducive to Carbon Capture & Disposal

Source Eastman Chemical Company

Source Eastman Chemical Company

Courtesy US Department of Energy
IGCC – The Good, the Bad, and the Ugly

**The bad**
- High capital cost
- More IGCC plants must be built to reduce cost and improve availability
- Currently not economical for low-BTU coals

Source: Eastman Chemical Company
IGCC – The Good, the Bad, and the Ugly

• **The ugly**
  - The business deal
    - Presently, there are no equipment suppliers, only technology licensors
    - Virtually all of the technology and performance risk is on the plant owner

DOE: We are looking to buy down the cost of the plant by 40-50%, so why are so few utilities considering IGCC?

Utility: Even if DOE puts up $500M on a $1 billion plant, we still have $500M at risk if the gasifier fails to perform. We are in the power business where reliability is king; we don’t want to be ‘guinea pigs’; let someone else try first.

PUC Commissioner: What does this gasification system cost per KW, and who is standing behind the performance guarantee?

But – GE Recently announced that they intend to purchase Chevron Texaco’s gasification business

Technology vendor: We are just making a component of the total plant, we do not want to be liable for delivering power – our units make fuels and by-products.

Lab: Our research shows that IGCC may not be the best choice for low-rank coals (sub-bituminous, lignite).

Source US Department of Energy
IGCC – The Good, the Bad, and the Ugly

• **The good**
  – Superior efficiency on Eastern Bituminous Coal
  – Flexible byproduct processing
    • Tri-generation opportunities
    • Hydrogen production
  – Superior environmental performance
  – Conducive to Carbon Capture & Disposal

• **The bad**
  – High capital cost
  – More IGCC plants must be built to reduce cost and improve availability
  – Currently not economical for low-BTU coals

• **The ugly**
  – The business deal
    • Presently, there are no equipment suppliers, only technology licensers
    • Virtually all of the technology and performance risk is on the plant owner

**But – GE Recently announced that they intend to purchase Chevron Texaco’s gasification business**

**Take away:** IGCC technology is strategically important towards keeping coal in the money; the bad and the ugly issues must be understood and resolved.
Impact of Coal Type on Technology Selection

Choices regarding coal type strongly influence technology selection.

Take away: IGCC plants become less competitive with low-BTU coals. IGCC is not a silver bullet; having other technology options available is strategically important.
Renewable Resources Technology Options

Biomass co-firing and wind energy are the primary options for providing large-scale renewable energy for AEP. The resources required for large-scale implementation are enormous and imply a “portfolio” approach.

<table>
<thead>
<tr>
<th>Percent Renewable Required</th>
<th>GWh Renewables Required</th>
<th>MW Renewables Required</th>
<th>No. Wind Turbines or MW Coal Plants</th>
<th>Capital Cost $M</th>
<th>Acres Land Impacted</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>5</td>
<td>10,000</td>
<td>3,260</td>
<td>2,175</td>
<td>3,261</td>
</tr>
<tr>
<td>Wind</td>
<td>10</td>
<td>20,000</td>
<td>6,520</td>
<td>4,350</td>
<td>6,523</td>
</tr>
<tr>
<td>Biomass</td>
<td>5</td>
<td>10,000</td>
<td>1,756</td>
<td>17,560</td>
<td>263</td>
</tr>
<tr>
<td>Biomass</td>
<td>10</td>
<td>20,000</td>
<td>3,510</td>
<td>35,100*</td>
<td>526</td>
</tr>
</tbody>
</table>

*Exceeds AEP’s total coal-fired capacity of ~ 25,000 MW
Note: Wind data assumes 35% capacity factor and biomass data assumes 65% capacity factor

Take away: There are CO₂ benefits with renewables; however, resource availability limits this potential.
Distributed Resources

Business opportunities represented by Distributed Resources

Peak management
Distribution asset management
Customer commercial services

Take away: There are many competing storage and generating technologies in development for distributed applications; several are likely to emerge as useful in targeted applications as costs continue to decrease.

Electricity Cost Ranges for DG Technologies

Source: CERA
Energy Storage

Business opportunities represented by Energy Storage

Asset Utilization/Deferral
Peak Management
Grid Stabilization
Power Quality
Energy Arbitrage

Take away: AEP has a heritage of active participation in developing energy-storage technology including demonstrating NAS and investing in Asymmetric Super capacitors.
**CO₂ Capture**

Carbon capture (“scrubbing”) is a difficult and expensive process:
- CO₂ is a very stable molecule
- CO₂ concentration is very low in flue gases
- Amine processes (MEA) are the only currently proven approach - high capital cost
- A large amount of steam is required to regenerate the amine (strip the CO₂ from the “carbon getter”) – large efficiency penalty

**Impact of Adding CO₂ Capture**

<table>
<thead>
<tr>
<th></th>
<th>Pulverized Coal</th>
<th>IGCC</th>
<th>NGCC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capital Cost</strong></td>
<td>+65% to 75%</td>
<td>+30% to 40%</td>
<td>+85% to 90%</td>
</tr>
<tr>
<td><strong>Efficiency</strong></td>
<td>-30% to 35%</td>
<td>-18% to 22%</td>
<td>-20 to 25%</td>
</tr>
<tr>
<td><strong>Cost of Electricity</strong></td>
<td>+50%</td>
<td>+30%</td>
<td>+60%</td>
</tr>
</tbody>
</table>

*Source: AEP, EPRI, and US DOE*

**Take away:** CO₂ scrubbing is very expensive; economic technologies do not now exist, however IGCC is currently more conducive to carbon capture.
Carbon Capture R&D  
Many Advanced Integrated Schemes Emerging

**Coal Gasification**
- CO$_2$ Hydrates
- Membranes
- Advanced Scrubbers
- Inexpensive Oxygen
- Chemical Looping

**Pulverized Coal**
- Oxygen Combustion
- Membranes
- Advanced Scrubbers
- New Sorbents
- Mineral Carbonation
- Chemical Looping

*Pathways to Zero Emissions*

Producing a concentrated stream of CO$_2$ at high pressure:
- Improves sequestration economics
- Reduces energy penalty

*Take away:* R&D and revolutionary technologies are required to keep coal viable. Less costly CO$_2$ capture technologies are being developed but are not currently available. *We are still looking for viable solutions.*

Courtesy US Department of Energy
Ohio River Valley CO$_2$ Storage Project - Mountaineer Plant

Test well at Mountaineer Plant, 9172 ft. deep, to understand CO$_2$ storage capability of deep saline aquifer

$4.6$-million project funded by DOE with cost sharing from AEP, Battelle, BP, Slumberger, Ohio Coal Development Office

*Take away:* Mountaineer Project has shown that one cannot assume that there is ample CO$_2$ storage capability near all of our coal-fired plants.
AEP’s Long Term Greenhouse Gas Strategy: A Portfolio Approach

**Renewables** (e.g. Biomass Cofiring, Wind)

CCX and Other Market Based Credits

New Generation R&D and Technology

Example: AEP Long-Term 20% Reduction: 35 MMTons

AEP Off-System Reductions (e.g. Forestry)

Long Term GHG Strategy
The Generation Technology Gap

Market Signals: Short-term focus without carbon capture
- Price Disadvantage & Other Market forces encourage:
  - Incremental expenditures and projects
  - Life extension

Sustainability Needs: Long-term focus with carbon capture
- R&D and policy strategies to resolve:
  - No proven advanced-coal generation technologies
  - Limited Renewable and Market options

Take Away: The lack of proven, advanced-coal generation technology options is a critical gap in AEP’s path forward. This technology is required to support a sustainable generation portfolio. Although required in the longer term, new technology development and deployment timelines drive the need to begin now.
AEP is collaborating with DOE, EPRI, and other utilities to commercialize advanced generation technologies which will allow coal to be used in a carbon-constrained world


**Advanced Coal Plant Partnership (ACPP)** – New public-private partnership led by EPRI E2I to accelerate transition to the next generation coal fleet.

**EPRI Partnership Program (EPP)** – Recent EPRI offer of a lead role for key funders

**Midwest Carbon Sequestration Regional Partnership** – DOE-funded program with 21 participants, led by Battelle to analyze CO₂ sequestration potential in Midwest region

**Take Away**: Advanced coal generation is recognized as an industry wide challenge. AEP has been engaged in collaborative programs but little has been accomplished to date. Missing is the clarity that a specific mission brings.
How can we close the gap?  
**LEADERSHIP**

- Lead the industry in focused R&D collaboratives
  - Establish partnerships with DOE, GTI, EPRI, industry peers, OEMs
  - Bring focus to existing programs: FutureGen, ACPP/EPP

- Develop & Execute Technical Strategy
  - Replacement of older plants
  - Engineering studies
  - Build partnerships with suppliers

- Establish Favorable Regulatory Framework
  - Supportive regulatory treatment
  - Federal and state incentives & participation

**Take Away:** Prioritize Company Efforts to Build an Advanced Coal Plant in 6-8 Yrs
Annex E: Environmental Scenario Analysis
AEP Environmental Scenario Analysis

June 7, 2004
Background and Purpose of the Analysis

- An important element of AEP’s ability to make sound investment decisions on behalf of its shareholders and customers is its ability to evaluate and analyze possible environmental regulations and uncertainties it faces in the future.
- Accordingly, the purpose of this analysis is to examine the costs to AEP of alternative environmental scenarios and assess the impact of these uncertainties on the company’s current and future capital investment decisions.
- The analysis herein assumes that AEP continues to serve its current set of customers and their growing demand for electricity. Further, new generating capacity needed to meet these demands is assumed to be owned and operated by AEP.
Environmental Scenarios

- Base EPA Proposed Regulations
- Carper Bill --- most recent version (S.843 in 2003)
  Carper multi-emissions and CO₂ allocations instead of EPA’s proposed regulations
- EPA Proposed Regulations plus McCain-Lieberman (S.139-immediate passage) – CO₂ cap at 2000 levels in 2010
- Sensitivity Analysis --- Low and High CO₂ Permit Price Range (See Appendix B)
Environmental Scenarios

- AEP analyzed a series of potential environmental regulatory futures and compared these to EPA’s proposed regulations for SO\textsubscript{2}, NO\textsubscript{x} and mercury (i.e., EPA’s proposed Clean Air Interstate Rule (CAIR) and mercury “cap-and-trade” rule).
- The McCain-Lieberman amendment, (in addition to EPA’s proposed regulations) was evaluated assuming immediate passage and implementation by 2010, and assuming passage in 2009 with implementation by 2014.
- The Carper 4-E bill (SO\textsubscript{2}, NO\textsubscript{x}, Hg and CO\textsubscript{2}) S.843 was evaluated assuming implementation in lieu of EPA’s proposed regulations.
- A range of CO\textsubscript{2} permit prices was analyzed to reflect a key cost uncertainty under the Carper and McCain-Lieberman legislation.
EPA Regulatory and McCain-Lieberman Scenario Results
## AEP Costs

### Estimated Pollution Control Cost for AEP Versus EPA Regulatory

<table>
<thead>
<tr>
<th></th>
<th>EPA Regulatory</th>
<th>EPA Reg w/ McCain Hi</th>
<th>EPA Reg w/ McCain Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NPV of Costs (2004-2030, in billions)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel</td>
<td>-0.0</td>
<td>-0.2</td>
<td></td>
</tr>
<tr>
<td>O&amp;M and Capex</td>
<td>+0.2</td>
<td>+0.1</td>
<td></td>
</tr>
<tr>
<td>New Plant Capital</td>
<td>+1.0</td>
<td>+0.4</td>
<td></td>
</tr>
<tr>
<td>Retrofit Pollution Control</td>
<td>-0.4</td>
<td>-0.1</td>
<td></td>
</tr>
<tr>
<td>CO₂ Permit Purchases</td>
<td>+0.0</td>
<td>+0.2</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2.6</td>
<td>+0.9</td>
<td>+0.5</td>
</tr>
</tbody>
</table>

### Major Retrofit Pollution Controls (2000-2020) (GW)

<table>
<thead>
<tr>
<th></th>
<th>EPA Regulatory</th>
<th>EPA Reg w/ McCain Hi</th>
<th>EPA Reg w/ McCain Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbers</td>
<td>11.9</td>
<td>-1.9</td>
<td>-1.5</td>
</tr>
<tr>
<td>SCRs</td>
<td>13.4</td>
<td>-1.1</td>
<td>+0.0</td>
</tr>
<tr>
<td>Baghouse/Carbon Injection</td>
<td>7.6</td>
<td>-0.7</td>
<td>-0.7</td>
</tr>
<tr>
<td>Coal Retirements in GW, by 2020</td>
<td>0.6</td>
<td>+0.0</td>
<td>+0.0</td>
</tr>
<tr>
<td>Cumulative CO₂ Permit Purchases in MMTons, by 2020</td>
<td>0</td>
<td>+0</td>
<td>+28</td>
</tr>
</tbody>
</table>

**Note:** EPA Regulatory NPV costs are incremental to a “status quo” scenario which assumes compliance with only the NOx SIP Call and Title IV NOx and SO₂ requirements.
AEP Costs

• Under EPA’s proposed regulations for SO₂, NOₓ and Hg, AEP is projected to spend almost $5 billion in pollution control capital through 2020. The net present value of incremental costs (beyond current SO₂ and NOₓ requirements) are $2.6 billion.

• Under McCain-Lieberman (passage today), AEP is estimated to offset approximately 10 million tons of CO₂ emissions by 2020 (which occurs as AEP’s electricity demand increases) to keep emissions at 2000 levels. Costs increase an additional $0.5 to 0.9 billion. This reflects the costs to offset CO₂ emissions through:
  – (1) more renewables, such as wind and biomass cofiring
  – (2) additional new plant capital; and
  – (3) purchases of emission offsets or credits.
AEP Capital Expenditures

Retrofit Capital

New Plant Capital

- EPA Regulatory
- EPA Reg w/McCain Hi
- EPA Reg w/McCain Lo

$Billion

2005 - 2020
AEP Capital Expenditures

- Under the EPA proposed regulations for SO$_2$, NOx and Hg, AEP is projected to spend almost $5 billion in retrofit pollution control capital between 2005-2020.
- Under McCain-Lieberman (passage today), near term pollution control capital (through 2010) is similar, as virtually the same units are economic to retrofit with scrubbers and SCRs. However, long term, retrofit pollution control capital declines by between $0.4 and $0.9 billion as CO$_2$ reductions are achieved through more gas CC, IGCC, and renewable (e.g., wind, biomass) generation.
- Thus, total capital expenditures through 2020 increase by $0.7-$1.4 billion, reflecting the increased new plant investment.
AEP Major Pollution Control Retrofits

- **2001-04**
  - Actual: 0.0
  - EPA Reg: 2.0
  - McCain Hi: 4.0
  - McCain Lo: 6.0

- **2005 - 2010**
  - Actual: 0.0
  - EPA Reg: 2.0
  - McCain Hi: 4.0
  - McCain Lo: 6.0

- **2011 - 2020**
  - Actual: 0.0
  - EPA Reg: 2.0
  - McCain Hi: 4.0
  - McCain Lo: 6.0

- **Carbon Injection**
  - Actual: 0.0
  - EPA Reg: 2.0
  - McCain Hi: 4.0
  - McCain Lo: 6.0
AEP Major Pollution Control Retrofits

• Under the McCain-Lieberman scenarios, AEP is projected to install approximately the same amount of scrubbers (9 GW) and additional SCRs (3 GW) by 2010 as in the EPA regulatory case. This occurs because these near term retrofit pollution control investments remain economic under virtually any potential environmental scenario.

• Post-2010, there is less scrubbing (about 1-2 GW less) and less carbon injection (up to 1 GW less), as generation shifts to advanced technologies and renewable sources.
AEP CO$_2$ Emission Reductions

CO$_2$ Offsets/Reductions in 2020: About 10 MM Tons
AEP CO$_2$ Emission Reductions

• Under McCain-Lieberman, AEP is assumed to limit (or offset) its CO$_2$ emissions to 2000 levels. Growth in AEP’s total electricity demand from customers results in higher generation from its existing coal-fired units and the addition of new generating capacity. Thus, AEP must reduce and/or offset about 10 million tons of CO$_2$ by 2020.

• AEP is projected to reduce/offset its CO$_2$ emissions through:
  – Installation of additional wind generation
  – Biomass co-firing with coal
  – Some coal generation replaced with gas combined cycle
  – Coal integrated gasification combined cycle (IGCC) with carbon capture and disposal
  – Purchased CO$_2$ credits or offsets (e.g., forestry)
AEP New Plant Capacity-2020

• Under the EPA Regulatory case, AEP is projected to build (or acquire) combustion turbines to meet growing peak demands in the near term in the Eastern part of the system and a few combined cycle gas units in the Western part of the system through 2010. Longer term (post-2010), AEP is also projected to build new IGCC coal plants to meet growing generation requirements in both the East and the West, and to replace older coal fired units which are no longer economic.

• The CO₂ reductions required under McCain lead to more IGCC builds, more combined cycle gas builds and more wind (in the West). With high CO₂ prices, some IGCC with carbon capture is installed (about 115 MW).

• IGCC coal builds are generally not economic until 2016, when lower cost, Nth of a kind designs are assumed to be available. (See Appendix B)
## AEP Costs under McCain Lieberman (2009 Passage)

### Estimated Pollution Control Cost for AEP Versus EPA Regulatory

<table>
<thead>
<tr>
<th>NPV of Costs (2004-2030, in billions)</th>
<th>EPA Reg w/ McCain Hi</th>
<th>EPA Reg w/ 2009 McCain Hi</th>
<th>EPA Reg w/ McCain Lo</th>
<th>EPA Reg w/ 2009 McCain Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
<td>-0.0</td>
<td>+0.2</td>
<td>-0.2</td>
<td>-0.2</td>
</tr>
<tr>
<td>O&amp;M and Capex</td>
<td>+0.2</td>
<td>-0.1</td>
<td>+0.1</td>
<td>+0.1</td>
</tr>
<tr>
<td>New Plant Capital</td>
<td>+1.0</td>
<td>+0.8</td>
<td>+0.4</td>
<td>+0.4</td>
</tr>
<tr>
<td>Retrofit Pollution Control</td>
<td>-0.4</td>
<td>-0.3</td>
<td>-0.1</td>
<td>-0.1</td>
</tr>
<tr>
<td>CO₂ Permit Purchases</td>
<td>+0.0</td>
<td>+0.0</td>
<td>+0.2</td>
<td>+0.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>+0.9</strong></td>
<td><strong>+0.7</strong></td>
<td><strong>+0.5</strong></td>
<td><strong>+0.5</strong></td>
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</table>

### Major Retrofit Pollution Controls (2000-2020) (GW)

<table>
<thead>
<tr>
<th></th>
<th>EPA Reg w/ McCain Hi</th>
<th>EPA Reg w/ 2009 McCain Hi</th>
<th>EPA Reg w/ McCain Lo</th>
<th>EPA Reg w/ 2009 McCain Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbers</td>
<td>-1.9</td>
<td>-1.6</td>
<td>-1.5</td>
<td>-1.5</td>
</tr>
<tr>
<td>SCRs</td>
<td>-1.1</td>
<td>-0.7</td>
<td>+0.0</td>
<td>+0.0</td>
</tr>
<tr>
<td>Baghouse/Carbon Injection</td>
<td>-0.7</td>
<td>-1.2</td>
<td>-0.7</td>
<td>-0.7</td>
</tr>
<tr>
<td>Coal Retirements in GW, by 2020</td>
<td>+0.0</td>
<td>+0.4</td>
<td>+0.0</td>
<td>+0.0</td>
</tr>
<tr>
<td>Cumulative CO₂ Permit Purchases in MMTons, by 2020</td>
<td>+0</td>
<td>+0</td>
<td>+28</td>
<td>+30</td>
</tr>
</tbody>
</table>
AEP Costs under McCain Lieberman (2009 Passage)

- McCain-Lieberman (2009) results in lower NPV costs versus immediate passage (up to $0.2 billion lower in the high case), reflecting later (2014) compliance with CO$_2$ limits.
- In the 2009 passage scenario, AEP is assumed to invest without foresight of the McCain CO$_2$ regulations. This was modeled by conservatively “fixing” the pollution control investments to those projected through 2012 under EPA’s proposed regulations. This scenario was compared to McCain (immediate passage) to determine whether there was potential “stranded” investment (i.e., could later become uneconomic under the McCain carbon constraints).
- However, the projected retrofit scrubbers, SCRs and carbon injection are very similar across the two scenarios (with low or high CO$_2$ prices) through 2012. This indicates that AEP’s investments to meet Phase I of the new EPA regulations are “economic” irrespective of the prospects of future carbon constraints similar to McCain-Lieberman.
Carper Scenario Results
AEP Costs under Carper

<table>
<thead>
<tr>
<th>NPV of Costs (2004-2030, in billions)</th>
<th>EPA Regulatory</th>
<th>Carper Hi</th>
<th>Carper Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
<td></td>
<td>+0.5</td>
<td>+0.7</td>
</tr>
<tr>
<td>O&amp;M and Capex</td>
<td>+0.1</td>
<td>+0.2</td>
<td></td>
</tr>
<tr>
<td>New Plant Capital</td>
<td>+1.3</td>
<td>+0.2</td>
<td></td>
</tr>
<tr>
<td>Retrofit Pollution Control</td>
<td>+0.3</td>
<td>+0.3</td>
<td></td>
</tr>
<tr>
<td>CO\textsubscript{2} Permit Purchases</td>
<td>+4.1</td>
<td>+1.7</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2.6</strong></td>
<td><strong>+6.4</strong></td>
<td><strong>+3.0</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Major Retrofit Pollution Controls (2000-2020) (GW)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbers</td>
<td>11.9</td>
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<td>+1.3</td>
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<td>13.4</td>
<td>+0.2</td>
<td>+0.0</td>
</tr>
<tr>
<td>Baghouse/Carbon Injection</td>
<td>7.6</td>
<td>-0.9</td>
<td>-0.0</td>
</tr>
<tr>
<td>Retirements in GW, by 2020</td>
<td>0.6</td>
<td>+0.6</td>
<td>+0.0</td>
</tr>
<tr>
<td>Cumulative CO\textsubscript{2} Permit Purchases in MMTons, by 2020</td>
<td>0</td>
<td>449</td>
<td>515</td>
</tr>
</tbody>
</table>

**Note:** EPA Regulatory NPV costs are incremental to a “status quo” scenario which assumes compliance with only the NO\textsubscript{x} SIP Call and Title IV NO\textsubscript{x} and SO\textsubscript{2} requirements.
AEP Costs under Carper

• Under Carper, AEP environmental costs increase substantially (*two to three times higher* than EPA’s proposed regulations) reflecting (1) tighter SO₂ and Hg limits longer term (2) and much more stringent CO₂ limits for AEP than McCain-Lieberman. In the latter case, this is because the “output-based” allocation provides far more allowances to incremental nuclear and gas, and far less to coal.

• Under the Carper bill, net present value costs would increase by an additional $3.0 to 6.5 billion:
  – (1) additional retrofit scrubbers and other pollution controls installed sooner
  – (2) costs to offset or reduce a very large amount of CO₂ emissions, reaching 58 million tons per year by 2020. Almost 2/3 of the Carper Bill’s costs are associated with these purchases and/or offsets
AEP Capital Expenditures -- Carper

**Retrofit Capital**

- EPA Regulatory
- Carper Hi
- Carper Lo

**New Plant Capital**

- EPA Regulatory
- Carper Hi
- Carper Lo

$Billion

2005 - 2020
AEP Capital Expenditures under Carper

- Although the same set of scrubbers and SCRs are selected through 2010 under Carper, near term capital is about $1 billion higher reflecting more carbon injection and baghouses and near term scrubbers to meet the tighter mercury limits.
- Over the 2005-20 period, retrofit pollution control capital increases under Carper to meet the tighter $SO_2$ and mercury limits.
- In addition, AEP new plant capital investment is estimated to increase by an additional $3.1 billion in Carper-High. This occurs as 0.6 GW more coal fired capacity is retired to meet the $CO_2$ limits and is replaced with new coal IGCC and combined cycle gas capacity. In addition, more wind is built.
AEP CO$_2$ Emissions

Graph showing AEP CO$_2$ emissions from 2004 to 2020, with lines for EPA Reg, McCain Hi, Carper Hi, and Carper Limit.
The most substantial difference between Carper and the EPA regulations are the carbon dioxide constraints. Owing to Carper’s “output-based” allocations, AEP is projected to reduce, offset or buy about five times as much CO₂ as under McCain-Lieberman by 2020.

While the amount of reductions/purchases or projected offsets are very large and thus quite expensive for AEP and its customers, they are probably feasible to achieve in the market because other utilities which are nuclear or gas based will receive far more allowances than they will need to comply. These companies will sell their “windfalls” to companies such as AEP that are coal-based.

In effect, the Carper bill increases electricity rates for states with large amounts of coal fired generation (e.g., the Midwest) and subsidizes electricity rates in states with large amounts of nuclear and gas generation (e.g., the Northeast).
Caveats and Uncertainties
CO₂ Allocation and Auction Issues

- Under McCain-Lieberman, CO₂ emissions are assumed to be allocated to existing units (as of 2000) with a set aside of 2 percent for new units. The legislative language leaves the final decision up to the Department of Commerce, including whether to include an “auction” of allowances in lieu of part of the allocation.

- An auction of allowances instead of allocation would increase AEP’s costs very substantially. For example, a very large 50% auction (as suggested in an earlier version of McCain-Lieberman) would increase AEP’s CO₂ offset and/or purchase requirements from about 10 MM tons per year by 2020 to about 100 MM tons per year. This would drive up AEP’s costs and the costs to its customers enormously.

- Similarly, an auction of allowances under Carper’s bill would also drive up AEP costs substantially.
Caveats and Uncertainties

The analysis assumes a set of future fuel prices, pollution control and new plant costs, and emission rates which are described in the Appendix. The emission and cost results presented herein are critically driven by these underlying assumptions.

Mercury control technology (e.g., carbon injection) has not been demonstrated commercially at coal fired units and it is uncertain whether the removal performance can be achieved, particularly in the near term. **As such, the mercury constraints and carbon injection added in Carper by 2009 will likely be technically infeasible.**

Lower gas prices (or lower replacement power costs) would increase coal unit retirements in the analysis and reduce post-2010 retrofits, but previous analysis conducted by the company indicates that robust scrubber and other retrofit decisions prior to 2010 would be unchanged.

New energy legislation affecting new and retrofit capital costs is not included. However, the production tax credit (PTC) at 1.5 cents/kWh was assumed to be extended and applicable to wind that comes on-line through 2010. The PTC is not assumed to be applicable to biomass co-firing.
Appendix A: Additional Detailed Forecasts
Detailed Forecasts

• Detailed forecasts are provided in this Appendix for each of the scenarios described in this report.
• Please note that the emission, cost and investment forecasts throughout this report are for the AEP system only and excludes recently divested generation capacity (e.g., Texas power plant divestitures).
• AEP system capacity includes all partially and fully owned generating capacity. The exception is AEP’s portion of OVEC and IKEC capacity, which is independently managed.
AEP SO$_2$ Emissions

Note: McCain-Lieberman SO$_2$, NOx and Hg emissions are not shown as they are virtually identical to EPA Regulatory case.
AEP East NOx Emissions

Note: McCain-Lieberman SO\textsubscript{2}, NOx and Hg emissions are not shown as they are virtually identical to EPA Regulatory case.
AEP Hg Emissions

Note: McCain-Lieberman SO₂, NOx and Hg emissions are not shown as they are virtually identical to EPA Regulatory case
AEP CO₂ Emissions

- EPA Reg
- McCain Hi
- Carper Hi
- Carper Limit

Purchases
# McCain-Lieberman Scenario Costs

## Estimated Pollution Control Cost for AEP

### Versus EPA Regulatory

<table>
<thead>
<tr>
<th></th>
<th>EPA Reg w/ McCain Hi</th>
<th>EPA Reg w/ 2009 McCain Hi</th>
<th>EPA Reg w/ McCain Lo</th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>NPV of Costs (2004-2030, in billions)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel</td>
<td>-0.0</td>
<td>+0.2</td>
<td>-0.2</td>
<td>-0.2</td>
</tr>
<tr>
<td>O&amp;M and Capex</td>
<td>+0.2</td>
<td>-0.1</td>
<td>+0.1</td>
<td>+0.1</td>
</tr>
<tr>
<td>New Plant Capital</td>
<td>+1.0</td>
<td>+0.8</td>
<td>+0.4</td>
<td>+0.4</td>
</tr>
<tr>
<td>Retrofit Pollution Control</td>
<td>-0.4</td>
<td>-0.3</td>
<td>-0.1</td>
<td>-0.1</td>
</tr>
<tr>
<td>CO₂ Permit Purchases</td>
<td>+0.0</td>
<td>+0.0</td>
<td>+0.2</td>
<td>+0.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>+0.9</strong></td>
<td><strong>+0.7</strong></td>
<td><strong>+0.5</strong></td>
<td><strong>+0.5</strong></td>
</tr>
</tbody>
</table>

### Major Retrofit Pollution Controls (2000-2020) (GW)

<table>
<thead>
<tr>
<th></th>
<th>McCain Hi</th>
<th>2009 McCain Hi</th>
<th>McCain Lo</th>
<th>2009 McCain Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbers</td>
<td>-1.9</td>
<td>-1.6</td>
<td>-1.5</td>
<td>-1.5</td>
</tr>
<tr>
<td>SCRs</td>
<td>-1.1</td>
<td>-0.7</td>
<td>+0.0</td>
<td>+0.0</td>
</tr>
<tr>
<td>Baghouse/Carbon Injection</td>
<td>-0.7</td>
<td>-1.2</td>
<td>-0.7</td>
<td>-0.7</td>
</tr>
<tr>
<td>Coal Retirements in GW, by 2020</td>
<td>+0.0</td>
<td>+0.4</td>
<td>+0.0</td>
<td>+0.0</td>
</tr>
<tr>
<td>Cumulative CO₂ Permit Purchases in MMTons, by 2020</td>
<td>+0</td>
<td>+0</td>
<td>+28</td>
<td>+30</td>
</tr>
</tbody>
</table>
## Carper Scenario Costs

### Estimated Pollution Control Cost for AEP
**Versus EPA Regulatory**

<table>
<thead>
<tr>
<th></th>
<th>EPA Regulatory</th>
<th>Carper Hi</th>
<th>Carper Lo</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NPV of Costs (2004-2030, in billions)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel</td>
<td>+0.5</td>
<td>+0.7</td>
<td></td>
</tr>
<tr>
<td>O&amp;M and Capex</td>
<td>+0.1</td>
<td>+0.2</td>
<td></td>
</tr>
<tr>
<td>New Plant Capital</td>
<td>+1.3</td>
<td></td>
<td>+0.2</td>
</tr>
<tr>
<td>Retrofit Pollution Control</td>
<td>+0.3</td>
<td></td>
<td>+0.3</td>
</tr>
<tr>
<td>CO₂ Permit Purchases</td>
<td>+4.1</td>
<td></td>
<td>+1.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2.6</td>
<td>+6.4</td>
<td>+3.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Major Retrofit Pollution Controls (2000-2020) (GW)</th>
<th>EPA Regulatory</th>
<th>Carper Hi</th>
<th>Carper Lo</th>
</tr>
</thead>
<tbody>
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<tr>
<td>Baghouse/Carbon Injection</td>
<td>7.6</td>
<td>-0.9</td>
<td>-0.0</td>
</tr>
<tr>
<td>Retirements in GW, by 2020</td>
<td>0.6</td>
<td>+0.6</td>
<td>+0.0</td>
</tr>
<tr>
<td>Cumulative CO₂ Permit Purchases in MMTons, by 2020</td>
<td>0</td>
<td>449</td>
<td>515</td>
</tr>
</tbody>
</table>

**Note:** EPA Regulatory NPV costs are incremental to a “status quo” scenario which assumes compliance with only the NOx SIP Call and Title IV NOx and SO₂ requirements.
AEP Major Pollution Control Retrofits – Carper Scenarios vs. EPA Regulatory

**2001-04**

- **Actual**: 0.0
- **EPA Regulatory**: 2.0
- **Carper Hi**: 4.0
- **Carper Lo**: 8.0

**2005 - 2010**

- **Actual**: 0.0
- **EPA Regulatory**: 2.0
- **Carper Hi**: 4.0
- **Carper Lo**: 8.0

**2011 - 2020**

- **Actual**: 0.0
- **EPA Regulatory**: 2.0
- **Carper Hi**: 4.0
- **Carper Lo**: 8.0

**SCR**

- **Actual**: 2005 - 2010
- **EPA Regulatory**: 2005 - 2010
- **Carper Hi**: 2005 - 2010
- **Carper Lo**: 2005 - 2010

**Carbon Injection**

- **Actual**: 2005 - 2010
- **EPA Regulatory**: 2005 - 2010
- **Carper Hi**: 2005 - 2010
- **Carper Lo**: 2005 - 2010
Appendix B: Major Analytic Assumptions
## AEP Emissions Caps by Scenario

<table>
<thead>
<tr>
<th>Timing</th>
<th>SO₂ (ktons)</th>
<th>AEP East NOx (ktons)</th>
<th>Hg (tons)</th>
<th>CO₂ (MMTons)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>EPA Regulatory</strong></td>
<td></td>
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</tr>
<tr>
<td>2004-09</td>
<td>674</td>
<td>39 (Seasonal)</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>2010 - 2017</td>
<td>347</td>
<td>103 (Annual)</td>
<td>2.48</td>
<td>None</td>
</tr>
<tr>
<td>2018+</td>
<td>243</td>
<td>72 (Annual)</td>
<td>1.09</td>
<td>None</td>
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<tr>
<td><strong>EPA Regulatory w/ McCain</strong></td>
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<td></td>
</tr>
<tr>
<td>2004-09</td>
<td>674</td>
<td>39 (Seasonal)</td>
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<td>103 (Annual)</td>
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<td>167</td>
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<tr>
<td>2018+</td>
<td>243</td>
<td>72 (Annual)</td>
<td>1.09</td>
<td>167</td>
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<tr>
<td><strong>EPA Regulatory w/ McCain 2009</strong></td>
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<tr>
<td>2004-09</td>
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<td>2010 - 2013</td>
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<td>2014 - 2017</td>
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<td>1.09</td>
<td>167</td>
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<tr>
<td><strong>Carper</strong></td>
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<tr>
<td>2004-08</td>
<td>674</td>
<td>39 (Seasonal)</td>
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<td>2009-2012</td>
<td>333</td>
<td>84 (Annual)</td>
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<tr>
<td>2013 - 2015</td>
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<td>73 (Annual)</td>
<td>1.03</td>
<td>120</td>
</tr>
<tr>
<td>2016+</td>
<td>166</td>
<td>73 (Annual)</td>
<td>1.03</td>
<td>120</td>
</tr>
</tbody>
</table>

Note: McCain CO₂ limits include a 2% holdback for new plant allocations.
Key Assumptions--- CO₂ Permit Prices ($/Ton CO₂)—McCain Lieberman

- 2010: Low---$9 … High….$23
- 2015: Low----$12 …High….$29
- 2020: Low----$15 …High….$37

Based on “The Full Costs of S.139, With and Without its Phase II Requirements” Prepared by Charles River Associates October 27, 2003. This is used as a primary source of the range in prices. This range brackets other price estimates by MIT and EIA for similar legislation.
Key Assumptions--- CO₂ Permit Prices ($/Ton CO₂)—Carper Bill

- 2010: Low---$4 … High….$10
- 2015: Low----$5 … High….$14
- 2020: Low----$6 … High….$20

Fuel Price Assumptions

- AEP-East Gas
- AEP-West Gas
- Delivered High Sulfur Coal
- Delivered Low Sulfur Coal

Graph showing fuel price trends from 2004 to 2020, with different prices and lines for each fuel type.
Fuel Price Assumptions

• Fuel prices represent latest AEP forecasts. Delivered fuel prices are representative; detailed prices are developed by plant and specific fuel type.
• Long Term (2008) natural gas price is approximately $5 per mmBtu growing 2+% per year delivered to AEP West plants. AEP East prices about $0.30 per mmBtu higher reflecting transportation differentials.
• Gas price forecast based on NPC Report projections and other private sources (e.g., CERA) and generally falls in the mid-range of these projections.
• No change in prices assumed in McCain-Lieberman and Carper Bill scenarios, reflecting finding of only modest changes in the EIA, MIT and EIA analyses.
# Retrofit Cost Assumptions

All Figures in 2004 Dollars

<table>
<thead>
<tr>
<th>Control Technology</th>
<th>Emissions Controlled</th>
<th>Removal Performance</th>
<th>Capital Cost $/kW (inc. overheads)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wet FGD</td>
<td>SO₂ / Hg*</td>
<td>95%</td>
<td>154-567</td>
</tr>
<tr>
<td>SCR</td>
<td>NOₓ / Hg*</td>
<td>87%</td>
<td>62-473</td>
</tr>
<tr>
<td>SNCR</td>
<td>NOₓ</td>
<td>25%</td>
<td>29-40</td>
</tr>
<tr>
<td>Combustion Mods</td>
<td>NOₓ</td>
<td>18-60%</td>
<td>5-209</td>
</tr>
<tr>
<td>Carbon Injection</td>
<td>Hg</td>
<td>87%</td>
<td>41-115</td>
</tr>
</tbody>
</table>

*NOTE: Hg removal is a co-benefit when Wet FGD and SCR are installed in series.*

All Figures in 2004 Dollars
For detailed New Plant costs, please see Annex D.
Appendix C: Analytic Framework and Capabilities
Multi-Emission Compliance Optimization

- State of the Art, Multi-Emission Compliance Optimization Model (MECO) developed to address complexity of multi-emission cases
  - Model built by CRA (former ICF “IPM developer”)
  - CRA is also EEI economic consultant
- Unique mixed integer/linear programming optimization model
  - Minimizes NPV of costs or maximizes NPV of net revenues
  - Dynamic “look-ahead” feature
  - Updated during 2003 to make “integer” choices
<table>
<thead>
<tr>
<th>INPUTS</th>
<th>Outputs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Macroeconomic</td>
<td>&quot;Optimum&quot; Compliance Plan</td>
</tr>
<tr>
<td>• Gas prices, power prices, new plant cost, emission allowance prices</td>
<td>For each scenario</td>
</tr>
<tr>
<td>Demand Forecast</td>
<td>Power Plant Investment Decisions</td>
</tr>
<tr>
<td>• Long-term load and generation forecast</td>
<td>By year for 2004-2020</td>
</tr>
<tr>
<td>Plant Cost</td>
<td>Cost Impacts</td>
</tr>
<tr>
<td>• Cap-Ex and O&amp;M</td>
<td>• Capital, O&amp;M, Fuel, and Total</td>
</tr>
<tr>
<td>Fuel Cost</td>
<td>Annual, Cumulative, and NPV</td>
</tr>
<tr>
<td>• Unit coal prices and fuel switching costs</td>
<td>Emission Projections</td>
</tr>
<tr>
<td>Emission Control Cost</td>
<td>• Emissions (SO₂, NOₓ, Hg, and CO₂)</td>
</tr>
<tr>
<td>• Retrofit emission control costs/removal</td>
<td>Allowance balances and &quot;banks&quot;</td>
</tr>
<tr>
<td>Emissions/Allowances</td>
<td></td>
</tr>
</tbody>
</table>
MECO – Key Advantages and Insights

• Ability to look at four emissions simultaneously
• “Dynamic” model providing an “optimal” solution
  – Considers future uncertainties or regulations
• Provides AEP with an internal value (i.e., ‘shadow price’) of emission allowances
  – SO₂, NOₓ, Hg (and CO₂)
  – With or without allowance and/or power purchases
• Helps to determine ‘robust’ emission control decisions today, as well as likely future direction where there is considerable uncertainty
Environmental Modeling Analysis – Major Sources of Inputs

AEP Commercial Operations, CERA/CRA
• Gas/coal/power prices, emission allowance prices
• Allowance balances/purchases

AEP Commercial Operations, Corporate Planning and Budgeting
• Long-term load and generation/dispatch forecast
• AEP East Forecast with PJM RTO participation

AEP Engineering/ Environmental Services/AEP Generation/ Alstom/Sargent & Lundy/EPRI
• Cap-Ex and O&M
• Retrofit control emission costs/removal; unit emission rates
• New Plant Costs

OUTPUTS
Annex F: Inventory of AEP Actions to Mitigate the Economic Impacts Associated with Air Emissions

**Greenhouse Gases**

**Public Policy**
- Development of publicly-available policy position paper on global climate change
- Proactive policy engagement on global climate change issues with:
  - Environmental groups
    - e.g., Forest carbon sequestration projects in partnership with The Nature Conservancy
  - Academic/Research institutions
    - e.g., Support for MIT Center on Energy and Environmental Policy Research, and MIT Carbon Sequestration Consortium
    - e.g., Support for EPRI’s Climate Change Research Program
  - Policy think tanks
    - e.g., Membership in Pew Center on Global Climate Change Business Environmental Leadership Council
  - Industry organizations
    - e.g., Leadership in BRT’s Climate RESOLVE program
    - e.g., Leader in EEI Electric Power Industry Climate Initiative programs
    - e.g., Leadership in International Emissions Trading Association (IETA)
  - Government agencies
    - e.g., Leadership in US DOE’s Climate Challenge and Climate Vision Programs
    - e.g., Participation in EPA’s Climate Leaders, Natural Gas Star and SFs programs
  - International organizations
    - e.g., Participation in international climate change conferences and negotiations (UNFCCC COP meetings)
    - e.g., Member of the e7 group of global electricity companies, supporting energy projects for sustainable development
  - Investors
    - e.g., Dialogue with concerned/interested investors
- Climate change-related policy advocacy
  - Seeking favorable tax treatment of non-GHG-emitting sources
  - such as wind, closed-loop biomass, solar
  - Encouraging New Source Review reform to stimulate efficiency improvements
  - Advocacy for unfettered global trading, banking provisions, Clean Development Mechanism (CDM) and Joint Implementation (JI) offsets, and early action credits
  - Proponent of federal legislation to
    - Establish a climate technology strategy for the U.S. (Sens. Byrd & Stevens),
    - Promote terrestrial carbon sequestration investments (Sens. Brownback & Wyden),
    - Provide credit for early GHG mitigation actions (Sens. Chafee, Lieberman), and
    - Fund climate-friendly energy technology RD&D (including FutureGen Project)

**Business Strategy**
- Founding participation in the Chicago Climate Exchange, an early GHG market
- Shoring up in-house analytical capacity (MECO)
- Investment in basic science R&D (EPRI)
- Participation in FutureGen initiative, a public/private partnership
- Participation in e7 CDM and JI projects
  - Galapagos wind repowering project
  - Bhutan micro-hydro project
  - Bulgaria energy efficiency project
  - Chile project proposal
- Diversification of portfolio of generation assets
  - Focus on investments in renewable energy sources

**Currently Regulated Emissions**

**Public Policy**
- Support for federal multi-pollutant (SO₂, NOx, mercury) legislation/regulation that coordinates reasonable
compliance deadlines and utilizes cap-and-trade systems
• Support for emissions trading, banking and other cost-effective mechanisms in legislative and regulatory approaches to reduce emissions
• Advocacy for cost-recovery at the state level of investments in pollution control equipment
• Advocacy for federal tax incentives for investment in pollution control equipment and research, development, and demonstration of advanced clean coal technologies

Business Strategy
• Fuel diversification of generating fleet through mergers, acquisitions, new plant construction and existing plant investments
  – e.g., more natural gas, wind, biomass co-firing
• Investments in innovative pollution control technologies
  – e.g., PowerSpan
• Development and ongoing refinement of in-house analytical capabilities
  – e.g., Multi-Emission Compliance Optimization model
• Investment in basic science and control technology research and development
  – e.g., Electric Power Research Institute activities

Technical Options and Initiatives
• SO2
  – Install wet/dry FGD
  – Fuel switching
• Participate in allowance trading markets
  – Banking early low-cost reductions
  – Improve efficiency at existing plants
• Shift utilization
  – Retire older, inefficient units, where cost-effective
• NOx
  – Install low-NOx burners and other combustion controls
  – Install SCR/SNCR and other post-combustion technologies
  – Participate in allowance trading markets
  – Improve efficiency
  – Fuel switching
  – Shift utilization
  – Retire older, inefficient units, where cost-effective
• Mercury (pending)
  – Install wet FGD (co-benefit)
  – Install SCR (co-benefit) and operate annually
  – Participate in allowance trading markets
  – Fuel switching
  – Install carbon injection with fabric filters
  – Improve efficiency
  – Shift utilization
  – Retire older, inefficient units, where cost-effective such as wind and biomass
• Evaluation of demand side response opportunities
  – Participation in U.S. Demand Response Coordinating Committee
• Major investor in forest carbon sequestration projects
  – Planting of over 62 million trees on company lands since 1944
  – Noel Kempff Mercado Climate Action Project, in which AEP helped to protect over 4 million acres of Bolivian rainforest to avoid the emission of 7 million tons of CO2 over 30 years
  – Guaraquecaba Climate Action Project, in which AEP helped to protect and restore over 17,000 acres of Brazilian rainforest to reduce or avoid 1 million tons of CO2 over 40 years
  – Catahoula Reforestation Project, in which AEP helped to acquire, protect, and restore over 18,000 acres of hardwood forests in Louisiana to capture 5 million tons of CO2 over 70 years
  – UtiliTree and PowerTree Projects
• Seeking 20-year operating license extension for Donald C. Cook Nuclear Plant

Temporal priorities
• Near-term:
  – Improve efficiency of existing energy system
  – Include carbon price in investment decisions
  – Increase investment in renewable energy systems
  – Continue to participate in terrestrial sequestration projects
• Long-term
  – Research, develop, demonstrate and globally deploy energy technologies that will decouple carbon emissions from energy consumption

Technical
• Efficiency improvements
  – Gas combined cycle repowering at Northeastern plant
  – Mothballing/retirement of inefficient gas steam units in Texas
  – Heat rate improvements at existing plants

• Research & Development
  – Geologic sequestration (e.g., Mountaineer project)
  – Energy storage (e.g., “Supercaps”, NAS battery)
  – Developed state-of-the-art systems for accurately monitoring & verifying benefits from forest carbon sequestration investments

Cross-Cutting

Policy advocacy
• Voluntary actions to build credibility, demonstrate policies
• Active research and analysis, on a company — and industry-wide basis, to inform policymaking
• Proactive engagement, on a company — and industry-wide basis

Coordinated actions to address currently regulated emissions and greenhouse gases
• Prioritization of investment in pollution controls at largest, newest units
• Exploration of biomass co-firing opportunities at smaller, older units

With respect to actions that AEP contemplated and did not undertake, management believes this is actually a fairly small list, consisting primarily of AEP’s inability to invest in some power plant efficiency projects, such as variable speed drive motor replacement, dense-pack turbine replacements, etc. due to New Source Review concerns. With respect to currently regulated emissions, management has awaited certainty in regulatory requirements before making significant investments, but did prepare for the inevitability of these controls through investments in R&D on the science to inform the policy debate and technology, especially with regard to multi-emission and mercury controls.