FEDERAL ACID RAIN LEGISLATION: ITS EFFECT ON KENTUCKY
(Senate Concurrent Resolution 73)

Research Report No. 256

Legislative Research Commission
Frankfort, Kentucky
January, 1992

KENTUCKY LEGISLATIVE RESEARCH COMMISSION

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FEDERAL ACID RAIN LEGISLATION: ITS EFFECT ON KENTUCKY

(Senate Concurrent Resolution 73)

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FOREWORD

Senate Concurrent Resolution 73, passed during the Regular Session of the 1990 General Assembly, directed that a study of the effects of federal acid rain control legislation on the Kentucky economy be conducted. The Subcommittee on Energy of the Tourism Development and Energy Task Force did most of the work on this study, under the chairmanship of Senator David Boswell and Representative Bud Gregory. The full task force adopted recommendations contained in Chapter VI of the report on November 12, 1991. The report was prepared by Mary Lynn Collins and Donna Cantrell. It was edited by Charles Bush and typed by Diana Hill.

The Capitol
Frankfort, Kentucky
January, 1992

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SUMMARY

Chapter I - Introduction

After years of debate, Congress, in late 1990, adopted acid rain control provisions which will significantly affect the nation's electric utilities and its coal industry. The acid rain provisions, set out in Title IV of the Clean Air Act Amendments of 1990, mandate greatly reduced sulfur dioxide emissions, a primary precursor to acid rain. Midwestern states, including Kentucky, will shoulder the greatest burden for Title IV implementation because of the high-sulfur coal that is mined in the midwest and the large number of electric utilities in the region which burn high-sulfur coal.

In anticipation of congressional action, the 1990 General Assembly directed, through Senate Concurrent Resolution 73, a study of the potential impacts on the state of any enacted federal acid rain legislation. The Tourism Development and Energy Task Force took on the task and the task force's Subcommittee on Energy spent most of the interim working on the issue.

Chapter II - Clean Air Act Amendments of 1990: Acid Rain Provisions

Title IV of the Clean Air Act Amendments (CAAAs) sets a permanent cap on the level of overall sulfur dioxide emissions released from electric power plants at 8.9 million tons annually by the year 2000, less than half the current emissions. To achieve this goal, a market-based emissions trading system was created, to be implemented in two phases. Phase I will begin January 1, 1995, and will target 110 coal-fired electric power plants with the largest sulfur emissions. All electric power plants will then be brought under the new acid rain controls beginning January 1, 2000.

Under the emissions trading system, each utility unit will be given annually a certain number of emission allowances, based on the unit's fuel consumption during 1985-1987. One allowance will permit a utility unit to emit one ton of sulfur dioxide (SO_2). Any allowances not needed by a utility unit can be banked for future use, traded within the utility's system, or sold on the open market. Utilities which emit more sulfur dioxide than the allowances they hold will be subject to a fine and more stringent requirements. Power plants coming on line after 1996 will not be allocated any allowances and will have to purchase needed allowances.

In order to achieve sulfur emission reductions, utilities will be forced to make significant changes in at least some of their plants. And because they will be allotted a limited and set number of allowances to emit sulfur, they will be forced to continue to make sulfur emission reductions or buy allowances as their systems grow. Compliance options being considered by coal-burning utilities include: (1) installing expensive pollution control equipment; (2) switching to a lower-sulfur fuel; (3) instituting energy conservation projects; (4) purchasing emission allowances; or (5) closing older utility plants.

Utilities will also be required to reduce nitrogen-oxide emissions, but no emissions trading system for them is provided.

Another key provision of the legislation is a program to aid coal miners put out of work because of the new clean air rules. The program will provide extended unemployment assistance for miners enrolled in a retraining program.

Chapter III - The Economics of Kentucky Coal Markets

The CAAAs will result in changes in coal markets, especially the demand for coal by electric utilities. These changes will significantly effect Kentucky coal production and employment.

Market adjustments are not new to Kentucky's coal mining industry. This sector has undergone significant adjustments over the last two decades. State coal production increased from 125.3 million tons in 1970 to 172.5 million tons in 1990. Coal mining employment increased through the 1970's to 50,806 jobs in 1981. However, in the 1980's coal mining employment declined, even as coal production increased. By 1990, there were only 30,498 people employed in coal mining. This fundamental structural change was facilitated by dramatic increases in productivity in coal mining, due to both the adoption of new technologies and a consolidation of companies within the industry. These structural shifts were reflected in both the east and west Kentucky coal fields.

The adjustments in Kentucky's coal mining sector have been generated by shifts in national coal markets, changes in environmental policies, and developments in international energy markets. Production of coal in the western United States has increased substantially over the last twenty years. From the early 1970's to 1987, Kentucky was the leading coal-producing state in the United States. However, Kentucky's share of U.S. coal production is declining; Wyoming has been the nation's largest producer of coal since 1988.

Electric utilities are the primary market for coal. In 1990, 70% of east Kentucky coal was delivered to electric utilities. Eight states accounted for 86.1 percent of the east Kentucky electric utility market and only 11.1% was delivered to utilities in Kentucky. Electric utilities accounted for 95.0% of the west Kentucky coal market. Utilities in Kentucky were the largest purchasers of west Kentucky coal and accounted for 43.2% of total utility shipments.

Since the original Clean Air Act was passed in 1970, coal quality has been one of the major influences on the demand for coal. Coal quality varies significantly across the coal-producing regions in the United States, as well as between the two coal-producing regions in Kentucky. There are two coal quality characteristics which will be crucial in a utility's strategy to comply with the CAAAs: 1) heating capacity, and 2) sulfur content.

Both Kentucky coal-producing regions have coal that is high in heat capacity. In 1990, east Kentucky coal averaged 11,540 British Thermal Units (Btus) per pound, while west Kentucky coal averaged 11,540 Btus per pound. Coal from the Western United States is generally low in heating capacity. Wyoming coal delivered to electric utilities averaged 8,669 Btus per pound in 1990.

While both Kentucky coal mining regions produce coal that is high in heating capacity, the sulfur content of coal from the two regions differs significantly. East Kentucky coal is considered low-to-medium in sulfur content. In 1990, east Kentucky coal delivered to electric utilities averaged 1.07 percent sulfur by weight and had potential average emissions of 1.72 pounds of sulfur dioxide per million Btus. West Kentucky coal is high in sulfur content. In 1990, coal delivered to electric utilities from western Kentucky averaged 3.21 percent sulfur by weight and had average potential emissions of 5.56 pounds of sulfur per million Btus. Coal from the Western United States is broadly characterized as low in sulfur content. Wyoming coal delivered to electric utilities in 1990 averaged only 0.38 percent sulfur by weight and had potential emissions of 0.88 pounds of sulfur dioxide per million Btus.

A key factor affecting the demand for coal is the price. In 1990, the average mine price of east Kentucky coal was $26.44 per short ton, compared to $22.01 per short ton for west Kentucky coal. However, the average mine price of coal produced in the Western United States was $11.60 per short ton and Wyoming coal averaged only $8.43 per ton.

While the mine price of coal from the U.S. western region was significantly less than that of Kentucky, the average delivered cost, adjusted for heating capacity, is more comparable to Kentucky coal. Average delivered cost of coal reflects the mine price as well as processing and transportation costs. In 1990, the average delivered cost of east Kentucky coal was $1.68 per million Btu. The delivered cost of west Kentucky coal averaged $1.25 per million Btu. Wyoming coal averaged $1.33 per million Btu. These cost differentials will be crucial in a utility's choice in complying with the CAAAs.

Chapter IV - Economic Impact of Title IV of the Clean Air Act Amendments of 1990

The market adjustments which will result from the CAAAs will have both direct and indirect effects on the economies of coal-producing regions. The direct effects will include changes in coal production and coal prices. As coal production and mining employment increases, both companies and employees will spend more of their earnings in the local economy, thus generating indirect and induced economic effects. For example, coal companies purchase equipment, supplies, and services. Miners and their families spend earnings on housing, clothing, food, and other goods and services. Successive rounds of spending generate further economic impacts.

The Energy Information Administration (EIA) of the U.S. Department of Energy estimated the effects of the CAAAs on coal production and prices for both the east and west Kentucky coal-producing regions. EIA projected that by the year 2000, coal production in west Kentucky would be 19.6 million tons, or 35%, lower than it would have been without the CAAAs. From 2001 to 2010, it was projected that west Kentucky coal production would rebound moderately, due to the construction of new electricity generating units which would be equipped with either clean coal technologies or scrubbers.

East Kentucky coal production is expected to increase due to the CAAAs. By 2000, the CAAAs are expected to account for an additional 7.0 million tons of production, which represents a five percent increase. However, increases in production due to the CAAAs are expected to moderate by the year 2010.

The CAAAs are expected to have significant effects on coal prices. As the demand for low-sulfur coal increases, prices are expected to increase. Conversely, as the demand for high-sulfur coal decreases, prices are expected to decline. In the year 2000, the average mine price of west Kentucky coal is projected to be $2.65 per short ton, or nine percent, lower than it would have been without the CAAAs. The average mine price of east Kentucky coal is expected to be $3.26 , or 10%, higher, due to the CAAAs, by the year 2000.

The combined price and quantity impacts are reflected in the total value of production. As a result of the CAAAs, the total value of west Kentucky coal is projected to be $645 million lower in the year 2000. However, the total value of east Kentucky coal production is projected to be $731 million higher. Therefore, despite the declines in west Kentucky coal production, an increase in the average price of east Kentucky coal is projected to result in an increase in the total value of state coal production of $77 million.

While it is estimated that the total value of state coal production will increase, there will be significant differences in how the CAAAs affect the economies of the coal-producing regions within Kentucky. The estimates of the direct effects provided by EIA, the change in the value of coal production for each region, were used to estimate the indirect and induced economic impacts of the acid rain provisions of the CAAAs for Kentucky. These effects were estimated by using the Kentucky Regional Economic Model (REMI). REMI is an econometric model of the state and is disaggregated into six economic regions. The projected changes in the value of coal production were simulated for both the west Kentucky coal region and the east Kentucky coal region.

In the year 2000, the west Kentucky coal region is projected to experience substantial economic loss from the CAAAs. Total employment in the region is expected to be 10,792 jobs fewer than it would have been without the CAAA, representing a 5.2% change in the region. Wages and salaries are expected to be $267.1 million, or 7.2%, lower.

The east Kentucky coal region is expected to benefit from the CAAAs. The combination of higher levels of coal production and higher average prices for coal should contribute to substantial economic gains for this region. It is estimated that by the year 2000, employment will be higher by 14,091 jobs, or 6.1%, while wages and salaries are expected to be $333.7 million, or 9.1%, higher.

Chapter V - Legislative Activity

In the course of its work, the Subcommittee on Energy received testimony from coal producers, coal miners, utility representatives, university researchers, and representatives of a number of state agencies. Primary attention was given to those west Kentucky coal markets believed to be most immediately at risk.

Other states with high-sulfur coal were surveyed. Indiana, Illinois, Ohio, Pennsylvania, and West Virginia have all passed legislation in direct reaction to the CAAAs. Each state has enacted legislation that requires or encourages in-state utilities to install scrubbers and continue use of in-state coal. Legislation adopted includes utility rate regulatory reform, a utility tax credit for local coal purchased for scrubbed facilities, and a bond authorization for scrubber installation.

Electric-generating utilities in Kentucky, including the Tennessee Valley Authority (TVA), were asked to present their clean air compliance plans and make recommendations on how the state could mitigate the negative impacts of the acid rain legislation. Most of Kentucky's generating facilities have units that are affected in Phase I; most indicated that they anticipated rate increases.

Testimony by officials from TVA, the largest buyer of west Kentucky coal, created the most concern. TVA indicated that it was considering switching to either Wyoming or central Appalachian coal, displacing approximately nine million tons of west Kentucky coal annually. According to TVA's initial analysis, both of these options appeared to be cheaper than a third option: installing scrubbers to continue to burn Kentucky coal at current levels. TVA had suggested that before it could opt for scrubbers, it would need financial incentives from the state. However, later in the study process, TVA announced a compliance strategy that will not decrease the amount of west Kentucky coal it purchases or require concessions from the state.

Most of the utilities that testified, including TVA, cited lack of a low-cost disposal option for coal combustion waste as a potential problem with the scrubber option - since scrubbers produce large amounts of sludge material. Utilities which are regulated by the state public service commission also recommended certain rate reforms to make the scrubber option less risky.

An opportunity to replace some losses in the domestic coal market with export sales was identified. For example, European unification will reduce or eliminate government subsidies for domestic coal and create new demand for foreign coal. Even more significant, world-wide spread of clean coal technologies will create significant new markets for high-sulfur coal.

Two future challenges to the entire coal industry were identified. First of all, as the global warming debate gears up, support is increasing for reductions in carbon dioxide emissions which result from the burning of fossil fuels. Secondly, community opposition to coal as a fuel source appears to be growing, despite important new development in clean coal technology.

Finally, the subcommittee analyzed available resources to promote coal, conduct coal-related research, and to provide assistance to any workers displaced by the CAAAs.

Chapter VI - Findings and Recommendations

On November 12, 1991, the Tourism Development and Energy Task Force received a report from the Subcommittee on Energy and adopted final recommendations on SCR 73.

RECOMMENDATIONS

(1) The Kentucky Congressional Delegation should be petitioned to work for passage of: (a) a tax credit to utilities which purchase environmental control devices to comply with the Clean Air Act Amendments of 1990; and (b) an amendment to the Federal Tax Reform Act of 1986 to restore tax-free status to pollution control bonds issued specifically for compliance with Title IV of the Clean Air Act Amendments of 1990.

(2) The 1992 General Assembly should increase funding for the Governor's Office for Coal and Energy Policy.

(3) The Governor's Office for Coal and Energy Policy should be required by statute to develop strategies for the promotion of Kentucky coal as an environmentally responsible fuel and to issue a report to the General Assembly annually. The report should include: (1) identification of existing coal markets; (2) identification of any changes or potential changes in coal markets; (3) any recommendations on how the state might preserve its existing markets and attract new ones; and (4) identification of any coal-related research or demonstration projects which the state should consider assisting.

(4) If the BR 430 proposal, which would return more severance tax monies to coal-producing counties, is adopted by the General Assembly, the bill should be amended to allow those severance tax monies allocated for economic development to be used for a coal-related project, if that project will protect a Kentucky coal market from displacement under the Clean Air Act Amendments of 1990.

(5) There should be created and funded a regional economic development office in west Kentucky, similar to the East Kentucky Economic Development and Jobs Creation Corporation.

(6) The Department for Employment Services should act as the lead agency to: develop a strategy to counteract negative employment effects of the Clean Air Act Amendments of 1990; work with the Economic Development Cabinet, the Workforce Development Cabinet, the Labor Cabinet, Area Development Districts, and the United Mine Workers; and apply for all federal funds available to address such reduced employment.

(7) A new section of KRS Chapter 278, relating to public utilities, should be created to assure regulated electric utilities prompt and full recovery of costs associated with installation of scrubbers or clean coal technologies.

(8) The state's universities should be encouraged to pursue research on the characteristics of and alternative uses for coal combustion waste.

(9) The Transportation Cabinet should be directed to initiate new pilot projects on the use of coal combustion byproducts, particularly scrubber sludge, in its road construction activities.

(10) The Finance and Administration Cabinet, as the chief procurement agency of the state, and the Economic Development Cabinet should be directed to find new markets for coal combustion byproducts.

(11) The Natural Resources and Environmental Protection Cabinet should be directed to facilitate disposal of coal combustion waste in abandoned mine sites.

(12) State regulations on coal combustion utility waste, classified as special waste pursuant to KRS 224.868, should ensure protection of the environment but be no more stringent than federal law dictates.

(13) A 20% income tax credit against donations made to the Center for Applied Energy Research by utilities, coal producers, and any other corporate entity should be established.

(14) All state laws, tax policies, regulations, and regulatory procedures affecting the state's coal industry should be reviewed and recommendations for changes should be made to ensure Kentucky's ability to compete in domestic and foreign coal markets.

(15) The General Assembly and its interim committees should continue to monitor the effects of the acid rain provisions of the Clean Air Act Amendments of 1990, and should monitor global warming initiatives calling for significant reduction of CO_2.

CHAPTER I

INTRODUCTION

Members of the Kentucky General Assembly were not surprised when the 101st U.S. Congress, in its closing days, placed stringent new controls on the burning of coal by electric utilities. Proposals to control acid deposition, commonly referred to as acid rain, were introduced in Congress as early as 1981. From 1982 until 1990, interim committees of the Kentucky General Assembly studied congressional proposals to control acid rain and communicated regularly with the state's congressional delegation on the issue. Recognizing that Congressional action was close at hand, the 1990 General Assembly enacted Senate Concurrent Resolution 73 on March 29, 1990. Senate Concurrent Resolution 73 directed an interim legislative committee, the Energy Task Force, to study the potential impacts of federal acid rain legislation in Kentucky's economy and to develop a strategy for addressing those impacts.

On November 15, 1990, the President of the United States signed into law S.1630, the Clean Air Act Amendments of 1990, Public Law 101-5491. Title IV of the Act contains the acid rain legislation.

Acid rain forms when fossil fuel combustion from electric power plants, industrial boilers, and motor vehicles release pollutants, primarily sulfur dioxide (SO_2) and nitrogen oxides (NO_x), into the atmosphere. Reacting with the SO_2 moisture in the atmosphere, and NO_x emissions are converted into sulfuric and nitric acids, respectively. The acidic materials, which may be carried long distances by wind, are released back into the atmosphere or are deposited on the ground in the form of rain, fog, snow, gas, or dry particles. Acid rain, in certain concentrations and under certain conditions, can damage forests, lakes, streams, aquatic life, buildings, and monuments, and cause human respiratory problems.

According to a national inventory completed in 1985, electric utilities were responsible for 69% of SO_2 emissions in the United States, with most of those emissions created by coal combustion. The transportation sector was identified as the largest source catetgory for NO_x emissions, 43% of the total. Electric utilities were responsible for 32% of NO_x emissions.[1] Fairly early in the process, proposals to tackle the acid rain issue narrowed to one source: fossil-fueled electric power plants.

Although the Clean Air Act, prior to the 1990 Amendments, did not specifically address acid rain formations, it did require certain controls on SO_2 and NO_x for industrial power facilities, as well as electric utility power plants. However, as the phenomenon of acid rain was recognized and concern over the effects of acid rain grew in the 1980's, controls in the existing law were viewed as inadequate and support for increased controls grew, leading to the inclusion of Title IV acid rain provisions in the 1990 Clean Air Act Amendments.

The acid rain issue provoked much argument among the states and between the U.S. and Canada. Canada and the northeastern states initiated the congressional acid rain battle, claiming that their forested areas and lakes were suffering from the long-range transport of acid rain originating in the midwest.

Once it became clear that acid rain legislation would target emissions from coal-burning electric utilities, the congressional proposals pitted states with high-sulfur coal reserves against states with low-sulfur coal reserves. The mid-western states of Ohio, Indiana, and Illinois, which have high-sulfur coal, favored proposals to require installation of pollution control equipment on all existing coal-fired utility units. States with low-sulfur coal, such as Wyoming and Montana, pushed for proposals to give affected utilities more options for reducing sulfur emissions, including switching to their low-sulfur coal. States with utilities targeted for the largest SO_2 reductions, again, primarily midwestern states, argued for cost-sharing provisions where all electric consumers, nationwide, would be subject to a tax to be used to subsidize the cost of the acid rain controls. The regional battles still continue, months after the signing of the Clean Air Act Amendments, as the rules for implementation are being developed.

Kentucky, as one of the nation's largest coal-producing states, with large reserves of high-sulfur coal in the west and low-to-medium sulfur coal in the east, was in a particularly difficult position during congressional deliberations. Proposals which favored one of the state's coalfields were not always favorable to the other coalfield.

The state was one of the early supporters of clean coal technology development, contributing over $10 million for construction of the atmospheric fluidized bed combustion project at the Tennessee Valley Authority's Shawnee plant near Paducah. And much support did exist within the state and the General Assembly for the position that Congress should not act on the issue without sound scientific knowledge of the benefits and costs of new acid rain control. To gain this knowledge the federal government embarked in 1980 on one of the largest research projects of its kind ever undertaken, the National Acid Precipitation Assessment Program (NAPAP). The project took over ten years and $600 million to complete and involved the efforts of over 1000 scientists in the United States, Canada, and Great Britain.[2]

Ironically, the fiscal assessment by the NAPAP project was not available to either the Senate or House of Representatives as each chamber passed their initial version of the Clean Air Act Amendments. A draft of the report surfaced just a month prior to final action by a conference committee but had little effect on the legislative process.[3] The final NAPAP report raises serious questions as to whether the costs of the new acid rain controls outweigh the benefits NAPAP was able to identify.

The final bill gives utilities flexibility in making SO_2 and NO_x reductions. Pollution control equipment is not mandated and no cost-sharing provisions are included.

Task Force Activity

Soon after the President signed the Clean Air Act Amendments of 1990, hereafter referred to as the CAAAs, the Interim Energy Task Force began its work on Senate Concurrent Resolution 73. In November 1990, a subcommittee of the Energy Task Force met with researchers at the University of Kentucky's Center for Applied Energy Research and reviewed the center's current coal research. Also that same month the Energy Task Force received its first briefing on the Clean Air Act Amendments of 1990 from state officials in the Natural Resources and Environmental Protection Cabinet and the Governor's Office for Coal and Energy Policy.

In January 1991, when the General Assembly reorganized several House and Senate committees, the Energy Task Force's jurisdiction was broadened to include tourism and the name was changed to the Tourism Development and Energy Task Force. Because of the 1991 Extraordinary Session of the General Assembly, the new task force did not meet during the first three months of 1991. At its April meeting, the Tourism Development and Energy Task Force established the Subcommittee on Energy and assigned the subcommittee the task of completing the Senate Concurrent Resolution 73 study on acid rain legislation.

The subcommittee devoted most of the remainder of the interim to the study, hearing testimony from coal producers and coal miners, from electric utilities in the state, and from various state agencies which will be involved in implementation of the acid rain legislation. On November 12, 1991, the Tourism Development and Energy Task Force completed its work on SCR 73, with the receipt of the subcommittee's report and adoption of recommendations.

Review of Chapters

This report is the final product by the Tourism Development and Energy Task Force on Senate Concurrent Resolution 73. Chapter II describes the federal acid rain legislation, including an SO_2 emissions trading system, and discusses the various compliance options available to affected utilities. Chapter III presents coal mining trends in this state, as well as factors which affect national coal markets. Chapter IV is an analysis, based on a computer model simulation, of the effects of the federal legislation on the state's economy. Chapter V presents all issues identified by the various participants of the study process, and the final chapter presents the task force's findings and recommendations.

Future Review

As the Tourism Development and Energy Task Force worked on this issue, through its subcommittee, it quickly became apparent that the task force's work is preliminary. Title IV of the Clean Air Act Amendments of 1990 - as well as the entire act - is a very complicated piece of legislation, a product of much political compromise. The emissions trading system is experimental; there is uncertainty as to how or indeed whether the experiment will work. Congress left many of the implementation details up to the U.S. Environmental Protection Agency (EPA), which has not yet worked out many of those details. Utilities are now formulating compliance plans without the final rules; the task force completed its work under similar uncertainties. As recommended by the task force, the General Assembly, through its interim committee system, will need to continue to monitor implementation of Title IV of the Clean Air Act Amendments of 1990.

CHAPTER II

CLEAN AIR AMENDMENTS OF 1990: ACID RAIN PROVISIONS

When President Bush signed S. 1630 into law on November 15, 1990, a major overhaul of the nation's air pollution law was set into motion. The Clean Air Act Amendments of 1990 (CAAAs) are the first amendments to the Clean Air Act since 1977 and the first major environmental law of the 1990s. The amendments will require as many as 175 regulations.[4] The CAAAs, which include 11 titles, tighten air standards to control acid rain, urban air pollution, and toxic air pollution. The legislation sets out a new permitting program, strengthens enforcement efforts, and mandates additional clean air research. This chapter summarizes the acid rain provisions of the CAAAs and explores the various ways affected entities may comply.

Title IV, the acid rain title, mandates that by the year 2000, utilities' overall SO_2 emissions will be ten million tons less than they were in 1980. Nitrogen oxide emissions are to be two million tons less than they were in 1980. Reductions of SO_2 and NO_x will be accomplished in two phases. The U.S. Environmental Protection Agency (EPA) will administer the first phase; states with approved permit programs will administer the second phase. Whereas there will be no fees for permits in the first phase, there will be a permit emission fee in Phase II, which, in most states, will run \$25.00 per ton of emissions. All affected units are required to install continuous emission monitors to record the levels of SO_2 and NO_x emitted at specific time intervals.

Utility generating units larger than 25 megawatts will, at some point, become an affected source. Cogeneration facilities, facilities that produce both electricity and process heat from the same source, are exempt if they produce less than one-third of their electric output for use by a utility.

Sulfur Dioxide Reductions

Title IV's SO_2 reduction provisions represent a radical departure from federal emissions control programs of the past. A permanent annual sulfur emissions cap for electric utility plants is set at 8.95 million tons for the year 2000 and each year thereafter. This represents approximately a 50% reduction in SO_2 emissions.[5] No absolute caps on sulfur emissions are to be set for individual utilities. Instead the sulfur reductions will be accomplished through a market-based emissions allowance trading system. The underlying goal of the SO_2 provisions is to allow each utility flexibility to choose the most cost-effective way to make SO_2 reductions.

Affected units are to be given set allowances to emit SO_2. One allowance will permit an affected source to emit one ton of SO_2 during or after a specified calendar year. The allowances can be traded within the utility's own system, banked for future use, or sold on the open market. Utilities which exceed their emissions allowance and do not obtain any additional allowances to cover their deficit will be fined \$2000 per excess ton and will be required to offset the excess tons the following year. However, regardless of the number of allowances an affected source may hold, previously existing SO_2 air quality standards must still be met. For example, units which come under the New Source Performance Standard of 1977 will not be permitted to exceed their current SO_2 emission rate of 1.2 pounds per million Btus.

New utility units which come on line after December 31, 1995, will not be allocated allowances, but will be required to obtain allowances through the market system starting January 1, 2000, in order to operate. Existing units which are retired will continue to receive allowances which can be sold or used elsewhere in the utility system. Owners of industrial boiler systems and smaller exempt utility plants may voluntarily choose to come under the allowance program in order to obtain allowances for sale.

Phase I

Under the first phase, scheduled to begin January 1, 1995, and end December 31, 1999,

Table 1

Affected Kentucky Phase I Units and Their Sulfur Dioxide Allowances

Utility	Plant Name	Generator	Phase I Allowances
Big Rivers Electric Corporation	Coleman	1	11,250
		2	12,840
		3	12,340
East Kentucky Power Cooperative	Cooper	1	7,450
		2	15,320
Kentucky Utilities Company	E. W. Brown	1	7,110
		2	10,910
		3	26,100
Owensboro Municipal Utilities	Elmer Smith	1	6,520
		2	14,410
Kentucky Utilities Company	Gent	1	28,410
Kentucky Utilities Company	Green River	4	7,820
East Kentucky Power Cooperative	H. L. Spurlock	1	22,780
Big Rivers Electric Corporation	Henderson II	1	13,340
		2	12,310
Tennessee Valley Authority	Paradise	3	59,170
Tennessee Valley Authority	Shawnee	10	10,170

Source: Clean Air Act Amendments of 1990, Section 404, 42 USC 7651.

only the 110 largest utility plant emitters of SO_2 will be targeted. These Phase I units are in 21 different states, primarily in the midwest. Ten of the Phase I units, owned by six different utilities, are in Kentucky. (See Table 1.) Many of the targeted units, in and out of Kentucky, burn Kentucky coal. In fact, approximately 60% of coal produced in the west Kentucky coal-producing region goes to Phase I-affected units.[6]

Allowances, which are to be awarded annually for the duration of Phase I, are set out specifically for each unit in Title IV. The allowances are based on a 2.5 pounds per million Btu emission rate, multiplied by the unit's average fuel consumption for the years 1985, 1986, and 1987. Utilities with Phase I units may elect, with EPA's approval, to substitute a different unit to make the designated SO_2 reductions.

Phase II

The second phase begins on January 1, 2000, and all utility generating units of 25 megawatts or larger, including Phase I units, become affected units. Each unit will be allocated SO_2 emission allowances, but, in contrast with Phase I, allocation for each affected unit is not set out in the legislation. The U.S. Environmental Protection Agency (EPA) is to compute and publish a final listing of unit-by-unit allocations by December 31, 1992. The formula to compute allocations for most units will be based on a 1.2 pounds per million Btus emission rate, multiplied by the unit's average fuel consumption for the years 1985, 1986, and 1987. Additional allowances are to be given to those units with 1985 emission rates below 1.2 pounds per million Btus to allow them to increase their emissions by 20%. Various other formulas are set out that are applicable to only one or a handful of units. The CAAAs are the product of many political compromises, and Phase II allowances are riddled with the give and take of that political process.

Bonus Allowances

In addition to the annual allotments each affected unit is to receive based on its fuel consumption, there are a number of bonus allowances available in both Phase I and Phase II. Some of the bonus allowances will be automatically allotted to qualifying utility units; others will be awarded on a competitive basis to units which utilize certain compliance strategies. All bonus allowances will be terminated by the year 2010, with one exception. The bonus allowances are described below.

"Midwestern" Bonus Allowances. Affected units in Illinois, Indiana, and Ohio are to share 200,000 additional allowances each year of Phase I; affected Phase I units in Kentucky, Alabama, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia will share 50,000 additional bonus allowances annually, beginning in the calendar year 2000. These are the only bonus allowances that will extend beyond 2010.

Qualifying Technology Bonus Allowances. Bonus allowances of up to 3.5 million will be made available to utilities with affected Phase I units on a first-come, first-served basis, if they install a scrubber or other clean coal technology which achieves a 90% reduction in SO_2 emissions at an affected unit. Successful applicants will receive bonus allowances equal to two additional years' worth of the unit's regularly allotted allowances. The utility may then use those allowances to delay its Phase I compliance until January 1997, or it may install the technology early and bank or trade the bonus allowances. On top of this, successful applicants will receive what are termed "2 for 1" credits, whereby they will receive one bonus allowance for each ton of emission reductions they achieve below a 1.2 lbs. per million Btu emission level. The method for distribution of these particular allowances is one of the most hotly debated issues in implementation of the CAAAs and is discussed at greater length later in this report.

Similarly, utilities that elect to replace an existing coal-fired boiler with a qualifying clean coal technology under Phase II will receive allowances sufficient to extend the unit's Phase II compliance four years beyond the Phase II deadline. Unlike the Phase I technology bonus allowances, however, utilities will only receive these allowances to get them by until their new systems are up and running. They will not receive any bonus allowances once the clean coal technology is in place. The qualifying clean coal technology to be used must be one not in widespread use in 1990, thus eliminating conventional scrubbers from these particular allowances. In addition to the bonus allowance incentives, Title IV also gives certain regulatory breaks for clean coal technology demonstrations.

Phase II, Ten-Year Bonus Allowances. A reserve of 530,000 bonus allowances will be made available annually for the calendar years 2000 through 2009 for units in the following categories:

- Units with 1985 emission rates at or below 1.2 pounds per million Btus which were operating at less than 60% capacity during the baseline years, 1985-1987.
- Units with 1985 emissions between 1.2 and 2.5 pounds per million Btus which were operating at less than 60% capacity during the baseline years, 1985-1987. A number of midwestern utility units are expected to qualify under this category, since the midwest had not fully recovered from a national recession during those baseline years, 1985-1987.
- Oil and gas-fired utility units whose average annual fuel consumption during 1980-1989 consisted of 90% or more natural gas.
- All units in "clean" states with a 1985 statewide annual SO_2 emission rate at or below 0.8 pounds per million Btus may elect to share annually 125,000 of the 530,000 bonus allowances in lieu of other Phase II bonuses. These states include Arizona, Arkansas, California, Colorado, Louisiana, Montana, Nevada, New Mexico, Oklahoma, Oregon, Rhode Island, Texas, Utah, Vermont, and Wyoming.[7]

Conservation and Renewable Energy Bonus Allowances. A one-time pool of 300,000 allowances will be reserved for investments made in conservation measures and renewable energy derived from biomass, solar, geothermal, or wind. Allowances will be awarded on the basis of one allowance for each ton of SO_2 avoided by the adoption of eligible measures. These allowances will be available on a first-come, first-served basis beginning January 1, 1992. Utilities with affected units may qualify for these bonuses by adopting energy conservation measures, constructing renewable power plants, or purchasing electricity from such plants. However, certain conditions must be met, some of which are out of the utility's control and dependent on state regulatory policy:

(1) Qualifying conservation measures and renewable energy must not have been in operation before January 1, 1992;

(2) Regulated utilities must have a state-approved least-cost energy production plan; and

(3) For conservation measures only, public service commissions must have adopted a regulatory reform measure to ensure that a utility's rate of return is not penalized by investment in conservation.

Allowance Sales and Auctions

Concern that there might be hoarding of excess allowances prompted Congress to create an allowance reserve to stimulate the market. Each year of Phase I and II, 2.8% of each affected unit's basic allocation will be held back for government sale and auction. These sales and auctions will be conducted by the U.S. EPA. Proceeds are to then be returned to the affected units on a pro rata basis. Sales will be terminated when less than 20% of allowances available are sold in any two consecutive years. And the auctions will be canceled after 2002 if less than 20% of available allowances are sold in any three consecutive years.

Allowances sold in these sales and auctions will be of two types: spot purchases and advanced purchases. Spot purchases may be used in the year purchased or banked for future use, but advance purchases may not be used until the seventh year after purchase.

Direct Allowance Sale. Allowances under the direct sales will be offered at the fixed price of $1500 per allowance, adjusted for inflation. They will be available on a first-come, first-served basis to any interested party, except that non-utility energy generators, referred to as independent power producers, will have first opportunity to purchase. Table 2 illustrates the number of allowances that will be available for sale.

Table 2

Number of Allowances Available for Sale at $1,500 Per Ton

Year of Sale	Spot Sale (same year)	Advanced Sale
1993-1999		25,000
2000 and after	25,000	25,000

Source: Clean Air Amendments of 1990, Section 416, 42 USC 7651

Allowance Auctions. No minimum bid is established for the allowance auctions, which will, again, be open to anyone. Auctions will be conducted on a sealed-bid basis, with the allowances being sold to the highest bidder. Results of these auctions, including winning bids, will be made public. Individual holders of allowances may also include their allowances in the public auction. These participants may designate a minimum bid and will receive proceeds in full from the sale. The number of EPA allowances to be auctioned each year is shown in Table 3.

Table 3

Number of Allowances Available for Auction

Year of Sale	Spot Auction (same year)	Advance Auction
1993	50,000	100,000
1994	50,000	100,000
1995	50,000	100,000
1996	150,000	100,000
1997	150,000	100,000
1998	150,000	100,000
1999	150,000	100,000
2000 and after	100,000	100,000

Source: Clean Air Act Amendments of 1990 Section 416, 42 USC 76510

Nitrogen Oxide Reductions

Nitrogen oxide reduction provisions in Title IV do not at this time include a market-based allowance system similar to SO_2 provisions. However, an owner of two or more affected units may request approval to use an emissions average for all of its affected units. The U.S. Environmental Protection Agency will establish NO_x emission limits for all boiler types. Most units affected by Phase I SO_2 provisions will come under the NO_x limit at the same time. Nitrogen oxide limits for all other units will kick in on January 2000, the beginning of Phase II.

A great deal of flexibility is built into the NO_x reduction program. Emission limits are to be based on available technology. If, after installing appropriate control equipment, a unit fails to meet the relevant standard, there are provisions permitting a less stringent standard. Also, extensions for a compliance deadline may be granted if a utility can show that there is a shortage in supply of NO_x control technology.

Clean Air Employment Transition Assistance

During the congressional debates on acid rain, few disagreed with those who warned that significant new restrictions on SO_2 would create regional pockets of unemployment. Congress attempted to address the problem by including Title XI in the CAAAs, which provides employment transition assistance for workers laid off as a consequence of compliance with the CAAAs.

Title XI amends the Job Training Partnership Act (29 U.S.C. 1501) and authorizes an appropriation of $50,000,000 for FY 1991, and a similar amount for each year thereafter through FY 1995. These funds, when appropriated, will be distributed by the U.S. Department of Labor in the form of grants to states, employees, employer associations, and representatives of employers, to provide laid-off workers training and other employment assistance services, such as job search allowances, relocation allowances, and subsistence payments during training. These funds will be available to address unemployment related to any of the CAAAs provisions, but it is anticipated that most of the funds will go to service programs for unemployed miners. In fact, according to the conference agreement on the CAAAs, any miner terminated because of decreased demand for coal at a mine supplying a Phase I-affected unit is presumed to qualify for the Title XI funds.

Even if Congress appropriates the full amount authorized for Title XI, however, funds will be limited. Priority will be given to areas with the greatest numbers of CAAAs-related unemployment. The Department of Labor missed its May 1, 1991, deadline to propose regulations to carry out the employment transition assistance program. According to a Department of Labor representative, however, funding priority will also be based on the merits of the program services proposed by applicants as well as need.[8]

Future Regulation

The CAAAs call for a number of studies to be conducted by EPA and submitted to Congress, including: (1) the feasibility and effectiveness of an acid rain standard; (2) a listing of all lakes known to be acidified; (3) an analysis of Canada's acid rain control program; and (4) the feasibility of developing a program for SO_2 allowances to be traded for NO_x allowances. Results of at least two other studies discussed below could prompt EPA to initiate significant new controls on coal-based energy production facilities without prior congressional approval.

On January 1, 1995, and every five years thereafter, EPA is to transmit to Congress an inventory of national annual SO_2 emissions from industrial sources. When and if it appears that the nation's industrial facilities are approaching an annual SO_2 emission level of 5.6 million tons, EPA is directed to take whatever regulatory action necessary to cap annual industrial SO_2 emissions at 5.6 million tons.

Even though utilities are, at this time, exempted from the toxic air pollution provisions in Title III of the CAAAs, the regulatory door is left open. EPA is directed to study the health hazards associated with electric utilities' release of toxic pollutants controlled under Title III and to prepare a report for Congress

Table 4

Schedule for Selected Acid Rain Regulations

May 1, 1991	Department of Labor is to prescribe rules for Clean Air Employment Transition Assistance.
November 15, 1991	EPA is to issue final rule on allowance sales and auctions.
May 15, 1992	EPA is to issue regulations on emission trading, acid rain permits, penalties for excess emissions, continuous emission monitoring system requirements, nitrogen oxide requirements for utility boilers, and conservation and renewable energy bonus allowances.
December 31, 1992	EPA is to issue a final list of unit-by-unit Phase II allowance allocations.

by the fall of 1994, identifying alternative control strategies, if warranted. EPA is authorized, upon completion of the report, to bring electric utilities under Title III regulatory control.

Many of the acid rain control rules have yet to be written. Congress left most of the details for federal agencies to work out and saddled them with an ambitious timeframe to complete their work. Table 4 lists deadlines for some of the more crucial regulations to be issued.

Utility Compliance With the Clean Air Act Amendments

With Title IV of the CAAAs, Congress decreed that there would be emission reductions and laid out broad parameters under which the reductions would operate, but it shifted actual decision-making about how to achieve those reductions from EPA to electric utilities. Since the NO_x requirements do not include a trading system, compliance strategies for NO_x will be more straightforward. This section concentrates on the more complex SO_2 compliance options.

The SO_2 allowance system will operate like a checking account, except that the banker, EPA in this case, will not penalize an overdrawn account until the end of the calendar year. Each year EPA will allocate a set number of allowances to each utility's account. Utilities may start the year with a surplus in their account, allowances they did not use the previous year. They may, at some point in the year, buy or sell additional allowances which will affect their account balance. At the end of the year, total SO_2 emissions by each utility will be tallied and EPA will take sufficient allowances from each utility account to cover the total amount of SO_2 emitted. Any utility with insufficient allowances will be subject to a fine and more SO_2 reductions.

Even though allowances are to be allocated based on an individual power plant unit, utility compliance strategies will be based on the total utility system. Utilities may target certain of their units to make all necessary SO_2 reductions. For example, XYZ Company has 10 units. Each unit will receive annually 20 allowances, which will permit each unit to emit 20 pounds of SO_2. But, currently, each of those units emits 30 pounds of SO_2 annually. Technically, each unit must reduce emissions by 10 pounds. But XYZ Company may decide that the least costly strategy would be to target five of the units, reduce emissions at those units by 20 pounds each, and make no modification in the other five units.

Before a utility may fashion a compliance strategy, it must first decide whether to make reductions merely sufficient to balance its SO_2 account or to make greater reductions than necessary in order to earn additional SO_2 allowances to sell or bank for future expansion. Phase I-affected utilities will have the option of making only those reductions necessary to Phase I compliance or to go ahead and make reductions dictated by Phase II at the same time. The decision to overcontrol or comply early will be driven by the utility's projection of the future value of an allowance. Estimates range from $300 to $1500 per allowance.[9] A utility that believes the value of an allowance will be in the lower range might opt to move as slowly as possible on its compliance plans, to be in a position to take advantage of promising new technological SO_2 controls which may be available in the near future. Another utility, believing an allowance will be worth the middle to upper range, may well favor a compliance strategy which will produce excess allowances to sell.

Electric utilities will have numerous compliance options and most final compliance strategies will probably incorporate more than one option. Among the compliance options utilities are considering are: (1) installation of control technologies; (2) switching to a lower-sulfur fuel; (3) purchasing allowances on the open market; (4) instituting energy conservation projects; and (5) closing older utility plants. The first two options are getting the most attention, especially by Phase I-affected utilities.

Technical Controls

Adoption of technological controls favors cheaper high-sulfur coal from west Kentucky and other high-sulfur coal areas. Utilities choosing to include technological controls in their compliance strategy are considering conventional flue gas desulfurization units, popularly known as "scrubbers," and new clean coal technologies. Scrubbers spray limestone into the smokestack. The SO_2 mixes with the limestone and is neutralized. Scrubbers are efficient in reducing SO_2 emissions, typically by 80 to 90%. Also they do not require boiler replacement. They are a known quality, having been used by some utilities since the early 1970's, after the passage of the Clean Air Act of 1970. One disadvantage to scrubbers is that they create large amounts of sludge. Retrofit costs for scrubber installations are estimated to cost $300 to $500 per ton of SO_2 removed.[10] These installations require a large amount of space and are not feasible at some sites.

New clean coal technologies, such as fluidized beds and integrated gasification combined-cycle systems, have recently been developed and are now commercially available. Advantages these newer technologies have over scrubbers include greater energy efficiencies, fewer waste disposal problems, lower operating costs, and the ability to reduce NO_x as well as SO_2. Most, however, require boiler replacement and involve greater capital expense than scrubbers. The major impediment to industry-wide adoption of clean coal technologies for CAAAs compliance, at this time, however, may be that they are relatively unproven. The U.S. General Accounting Office estimates that clean coal technologies now emerging are at least five to ten years away from widespread development.[11]

The CAAAs do provide incentives for installation of scrubbers and clean coal technologies. However, the limited quantity of bonus allowances for technology controls in Phase I may discourage some utilities from taking this option.

Fuel-switching

The emphasis in consideration of fuel-switching is primarily on a switch to a lower-sulfur coal. Significant SO_2 reductions can be made by switching to lower sulfur coals from the western region of the United States and from Appalachia. Wyoming coal, because it is so low in sulfur and because the minemouth price is so cheap (as low as $5 a ton), is receiving a lot of attention. But this option is not without risk. Significant increases in either minemouth coal prices or transportation costs could significantly increase the average delivered cost to utilities.

As a variation of the fuel-switching option, very low-sulfur coal could be blended with high-sulfur coal. The new rail-barge to be built at West Paducah, Kentucky, at the confluence of the Ohio and Mississippi Rivers, is designed for coal-blending operations.

Since natural gas contains no sulfur and little nitrogen, this fuel is also expected to be a compliance option. Boilers can be modified to burn a blend of coal and gas, providing the utility a great deal of flexibility. In an unusual utility regulatory proceeding in West Virginia, a natural gas transmission company is challenging a local utility's CAAAs compliance decision to install scrubbers and continue to burn high-sulfur coal on the basis that a switch to natural gas would be more cost-effective.

Co-firing coal with wood or solid waste or switching to oil may also have limited applications in achieving SO_2 reductions.

Electricity generating units are designed for certain coals. In order to burn coal or another fuel that is significantly different in quality (Btu or ash) than originally designed for, units must undergo modifications. In addition, switching to natural gas would require pipeline installation. All of these modifications require capital investments and will increase the relative cost of coal switching.

Purchase of Allowances

Another compliance option, which offers great flexibility to utilities, is purchase of additional allowances needed to balance the SO_2 account. It is likely that this option will at least be used to supplement other actions to reduce SO_2 emissions, so that no changes are necessary in either equipment or coal suppliers at some units. This option could also be used as a short-term solution, buying time until a pollution control technology is installed or boilers modified for fuel switching.

As mentioned earlier, there is a great deal of uncertainty related to the allowance market. It has been suggested that utilities may hoard allowances in order to either ensure that sufficient quantities are available for future generation capacity or for price speculation. If the supply of allowances is limited by hoarding, the price of the allowances would increase . However, provisions in Title IV for special sales and auctions should ensure the availability of allowances. In addition, a recent decision by the Chicago Board of Trade to create a futures market for SO_2 allowances should go a long way towards stabilizing allowance trading. If the price of allowances is kept sufficiently low, this option will play a larger role in compliance strategy.

Energy Conservation

If utilities can cut their demand by encouraging customers to buy electric-conserving appliances, install new energy-efficient lighting, and adopt other conservation measures, they can burn less and expend fewer allowances. Bonus allowances may encourage this option, but it is not likely to be used as the primary compliance strategy for utilities needing to make large SO_2 reductions. At the same time, it promises to be a useful tool to enable a utility to continue to serve new customers.

Retire Older Plants

One of the driving forces behind Title IV of the Clean Air Act Amendments of 1990 is to address a flaw in the Clean Air Act Amendments of 1970: built-in incentives to extend the life of the nation's dirtiest power plants. The 1970 legislation exempted plants built before 1970 from new SO_2 and NO_x emission standards. Industry responded by extending the life of their fossil fuel plants well beyond the traditional life of 30 to 40 years, to avoid the stricter air quality standards. In 1985, these exempt plants were responsible for 88% of the SO_2 and 79% of the NO_x emitted by fossil plants in the United States.[12] Most of these plants are now targeted for Phase I emission reductions. Title IV permits a utility to shut down one of these older plants but to continue to receive the SO_2 allowances tagged to the plant. The utility may then build a newer, cleaner facility and end up with surplus allowances.

Other Considerations

Utilities will not be making their SO_2 reductions in a vacuum. The allowance trading system promises to broaden participation to a host of new players: brokers, industrial coal users, coal producers, pollution control vendors, and state governments. A utility could agree to help finance pollution control at an industrial site which opts to come in under the emission trading system in return for allowances earned by the project. Some scrubber vendors are already offering to lease their equipment to utilities in exchange for extra allowance credits. Future coal contracts may specify a package deal: the coal and a certain number of emission allowances, based on sulfur content of coal purchased. Even state governments, wishing to preserve local mining jobs, could share some of the risks utilities face by guaranteeing a certain value for allowances utilities plan to buy or sell. Figure 1 illustrates some of the players and strategies of the new market.

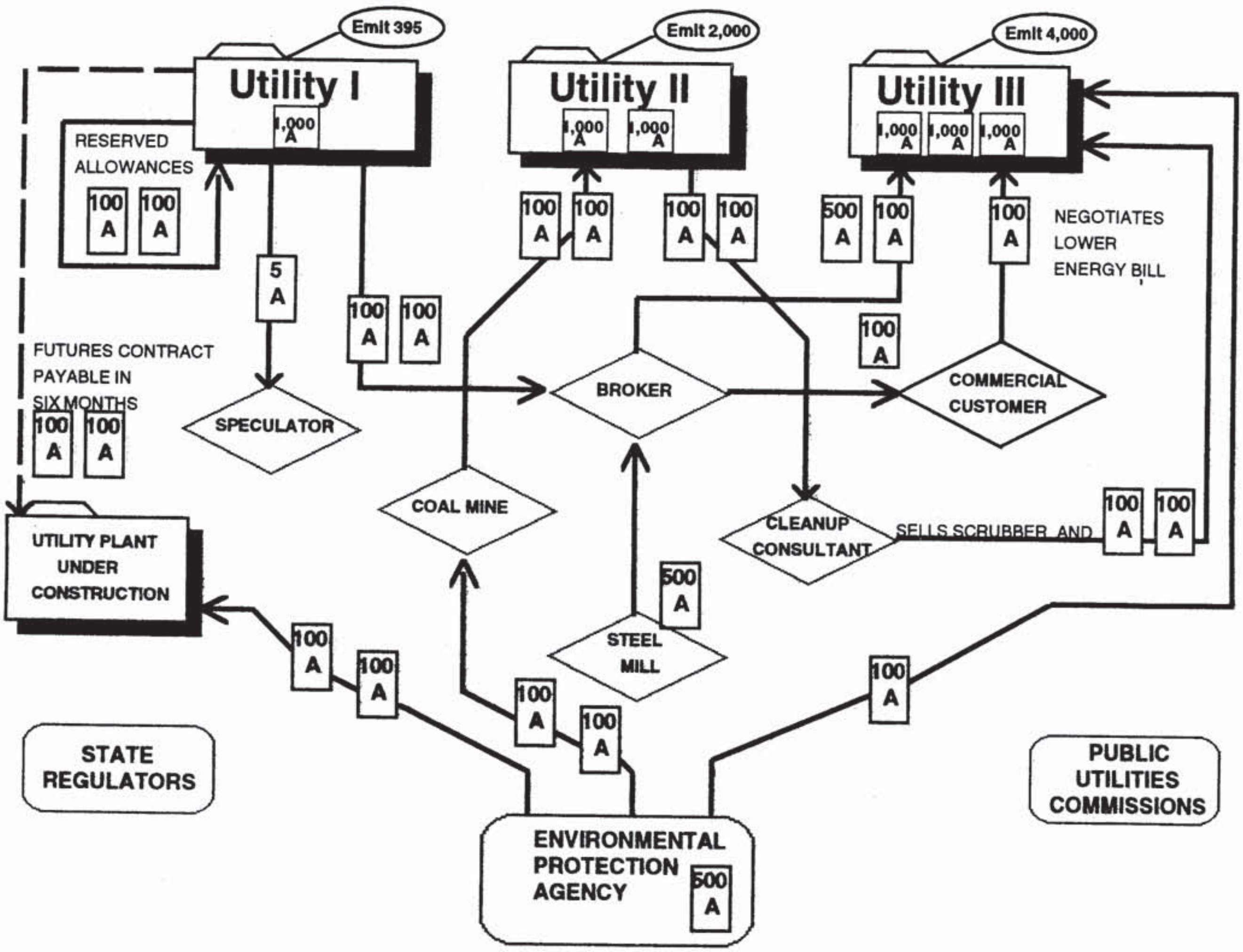
Given the range of options, there is much uncertainty as to how electric utilities will comply with the new regulations. Most analyses of the supply and demand for coal assume electric utilities will pursue a strategy which minimizes their cost of compliance. A utility is expected to choose the least-cost strategy. However, other factors may influence the choice of a compliance strategy.

Regional economic considerations may prompt a utility to choose one strategy over another. For example, a utility located in a high-sulfur coal-producing region may install scrubbers, in order to support the local economy. Such a choice may offer other economic benefits. If economic activity in a service area declined significantly, the demand for electricity would also decline, resulting in decreased revenues for the utility.

If a utility's long-range plans are to switch to fuels other than coal (nuclear, oil, or gas), purchasing low-sulfur coal may be deemed the appropriate strategy. This choice would enable compliance without requiring significant long-term capital investments, which would limit flexibility.

Finally, state policies will influence compliance decisions. Typically, utility regulatory rate procedures favor fuel-switching over installation of pollution control equipment. Most regulatory bodies require prior approval for capital investments but often do not review fuel switching until after it has been done. However, some states have adopted legislation which requires utilities to use high-sulfur coal produced in those states or creates incentives to purchase in-state coal in order to reduce the economic impacts on regional economies. If a utility chooses a least-cost approach, this will minimize the effects on electric rates. However, policies which seek to mandate compliance strategies rather than allowing the utility to choose a minimum cost strategy may effectively increase a utility's compliance cost, thereby resulting in higher electric utility rates.

Figure 1 Allowance-Trading Scenario



ANNUAL ALLOWANCE ACCOUNTS

	UTILITY I	UTILITY II	UTILITY III	NEW PLANT
ALLOTED	1,000	2,000	3,000	0
ACQUIRE	0	200 + COAL	1,000	400
SELL	405	200	0	0
RESERVE	200	0	0	400
EMIT	395	2,000	4,000	0

SOURCE: John Palmisano, AER*X

ALLOWANCE-TRADING SCENARIO portrays some of the players and strategies in the new market. Initially utilities hold most of the allowances (denoted by "A"). They either use their allowances (by emitting sulfur dioxide) or sell them. Brokers may arrange sales. Plants under construction must buy allowances to cover their future emissions. The EPA plans to hold annual auctions to give firms opportunities to buy allowances. Industrial sources of SO2, such as steel mills, may "opt into" the program by complying voluntarily with the standards; the EPA then awards them allowances. Other companies-coal mines, cleanup consultants or commercial customers-may give or take allowances in lieu of cash payment for goods and services. The EPA also tracks utilities' balance of allowances (left). State regulators and public utilities commissions help the EPA oversee the program.

CHAPTER III

THE ECONOMICS OF KENTUCKY COAL MARKETS

Title IV of the Clean Air Act Amendments of 1990 (commonly referred to as the acid rain provisions) will result in changes in coal markets. These changes will significantly impact Kentucky coal production and employment, and the regional economies dependent upon coal production. Compliance with these provisions by electric utilities will also increase the cost of generating electricity, thereby increasing electric utility rates of Kentucky residents and businesses.

This chapter reviews coal-mining trends in the state and in both coal-producing regions from 1970 to 1990. It then reviews factors affecting the demand and supply of coal, and the influence of the Clean Air Act Amendments (CAAA) on markets for Kentucky coal. This background information will be useful in identifying implications of the CAAA for Kentucky.

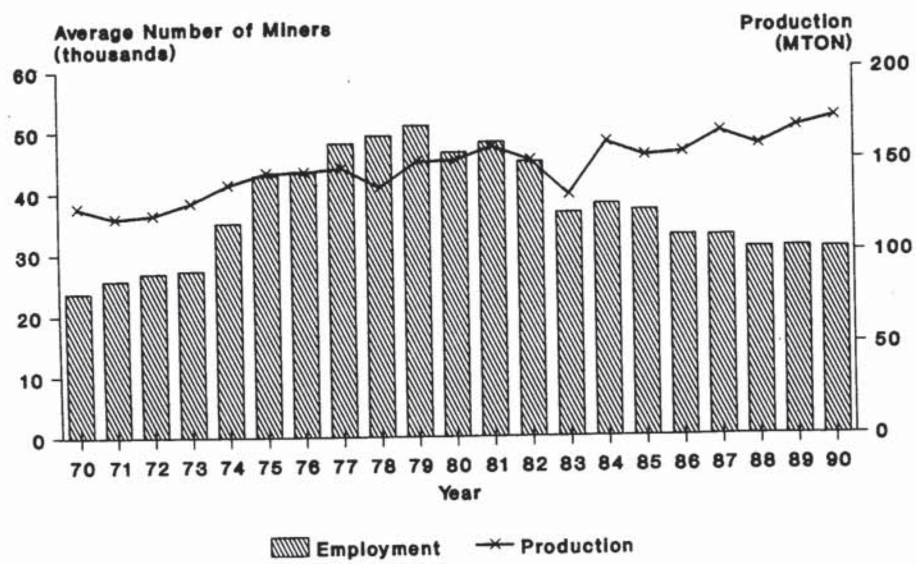
Trends in Coal Production and Employment

In 1970, Kentucky coal production totaled 125.3 million tons. By 1990, production increased to 172.5 million tons (Figure 2), reflecting an average annual growth rate of 1.8 percent.

The increased demand for coal increased the demand for labor, which created jobs in both the east and west Kentucky coalfields. In 1970, there were 23,713 Kentuckians employed in coal mining. By 1979, this number had increased to 50,806 people.

The increase in coal demand was not the only factor which prompted employment increases. The Federal Coal Mine Health and Safety Act of 1969 and the Surface Mining Control and Reclamation Act of 1977 required additional

Figure 2
Kentucky Coal Mining Trends
1970-1990



.y Economic Information System, University of Kentucky and annual issues
.al Production, U.S. Department of Energy

personnel to comply with the new regulations. Thus, the number of workers required to mine a given amount of coal increased .

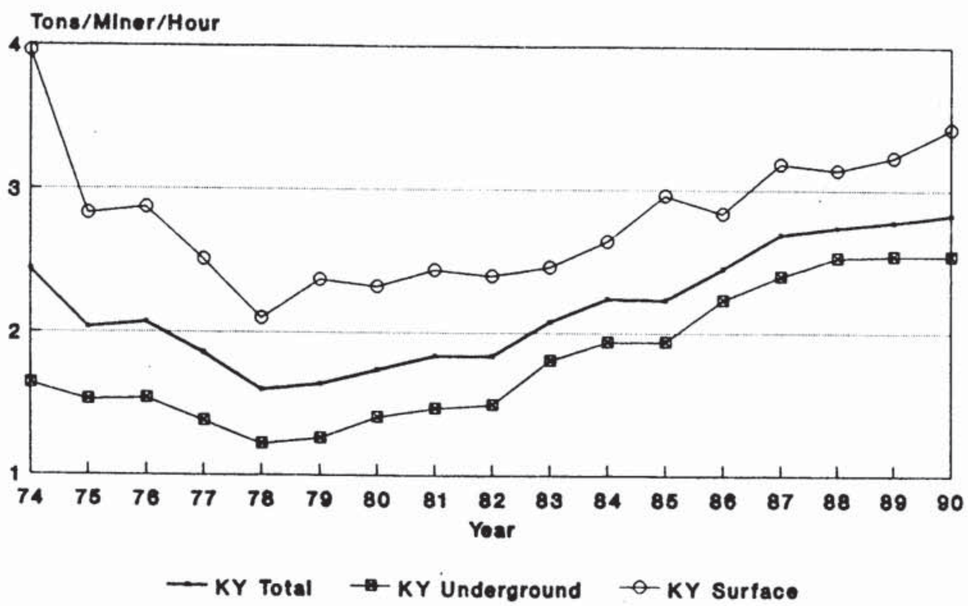
When oil prices declined in the 1980's, coal producers had to become more competitive by reducing coal prices, which in turn increased the pressure for cost reductions. The major source of cost reduction was increased productivity. Thus, while coal production continued to increase, coal-mining employment declined steadily (Figure 2). From 1981 to 1990, state coal production increased from 157.6 million tons to 172.5 million tons, while state coal employment decreased from 50,806 to 30,498.

Productivity in mining is measured as the amount of coal produced by one miner in one hour. In 1974, Kentucky mining productivity was 2.44 tons per miner per hour (Figure 3). Productivity declined to 1.60 tons per miner per hour in 1978. However, as producers adjusted to the new regulations, productivity increased. By 1990, productivity increased to 2.83 tons per miner per hour.

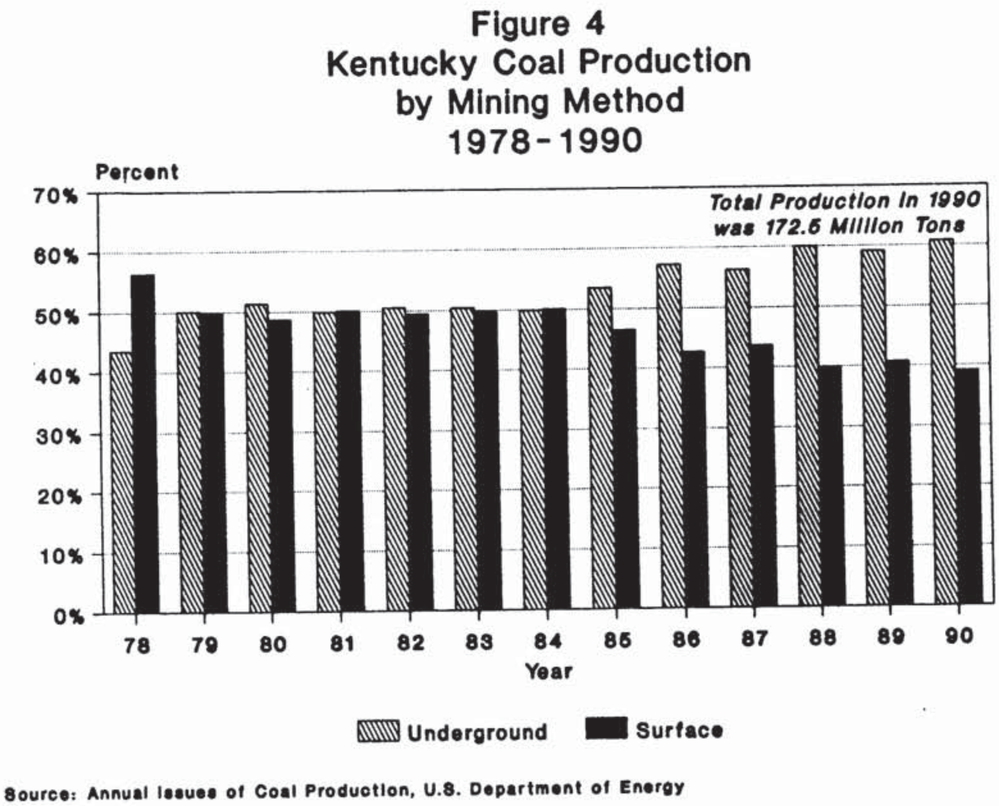
Productivity varies according to whether the coal is extracted by underground or surface methods. Surface mining requires fewer miners to produce a given quantity of coal. Through the 1970's and until 1982, surface mining accounted for the larger share of coal production (Figure 4). After this time, the share from underground production increased. By 1990, 61 percent of production was from underground mines. Contrary to conventional wisdom, gains in productivity in the industry have not been due to a greater reliance on surface mining. In fact, surface mining as a percent of total production has declined. Rather, productivity increases in coal mining were generated by significant advances in mining technology. For example, the use of continuous-mining equipment and longwall equipment significantly increased productivity in underground mining.

Thus, the most significant trend in the state coal industry the last decade has been the substitution of machines for people in the

Figure 3
Kentucky Coal Mining Productivity
By Coal Mining Method, 1974-1990



Source: Kentucky Economic Information System, University of Kentucky and annual issues of Coal Production, U.S. Department of Energy



mines. This change caused coal mining employment to steadily decrease even while coal production increased.

Gains in productivity were also generated by the closure of less efficient mines. The high coal prices in the mid-1970's, ease of entry to the industry, and relatively low production costs prompted many small producers to enter the industry. However, as production costs ncreased (with enforcement of environmental regulations) and prices declined in the early 1980's, the number of mines also declined. Larger companies became more efficient by closing their least productive mines and investing in equipment. Many smaller companies were caught between high production costs and weak prices and had few alternatives but to close.

Kentucky's Coal-Producing Regions

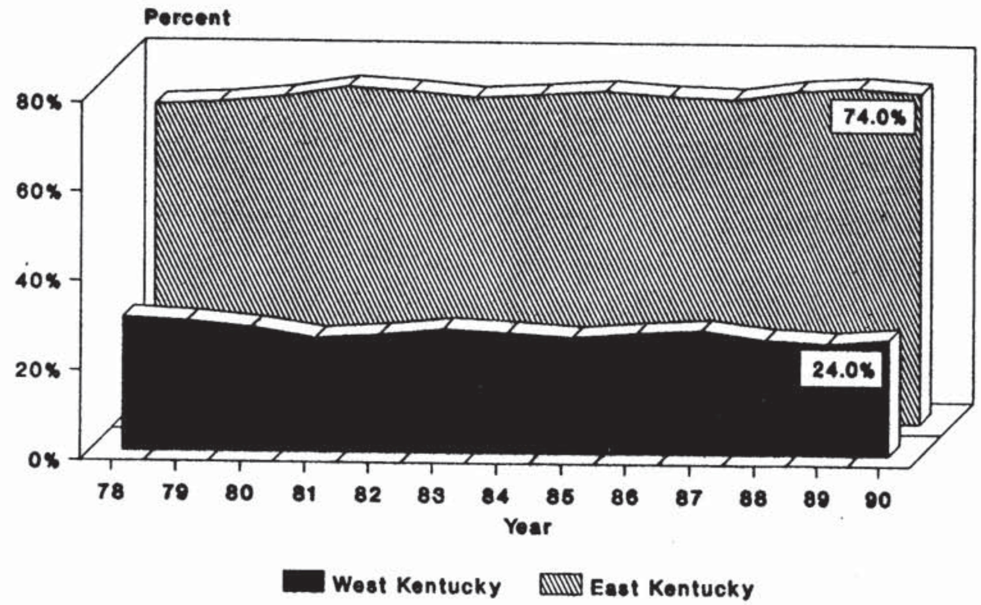
There are three major coal-producing regions in the United States: the Appalachian region, the Interior region, and the Western region. Kentucky has coal production in two of these regions. The eastern coalfields fall within the Appalachian basin, while the western coalfields fall within the Interior basin.

In 1978, coal production from east Kentucky accounted for 70.3 percent of state production, while west Kentucky accounted for 29.7 percent (Figure 5). Through the decade, east Kentucky increased its share, which by 1990 accounted for 74.0 percent of state production.

Since east Kentucky accounts for a higher share of production, it is not surprising that it also accounts for a higher share of employment (Figure 6). In 1970, east Kentucky accounted for 74.4 percent of coal-mining employment. This share increased to 81.7 percent by 1990. Conversely, west Kentucky's share of state coal-mining employment declined from 25.6 percent in 1980 to 18.3 percent in 1990.

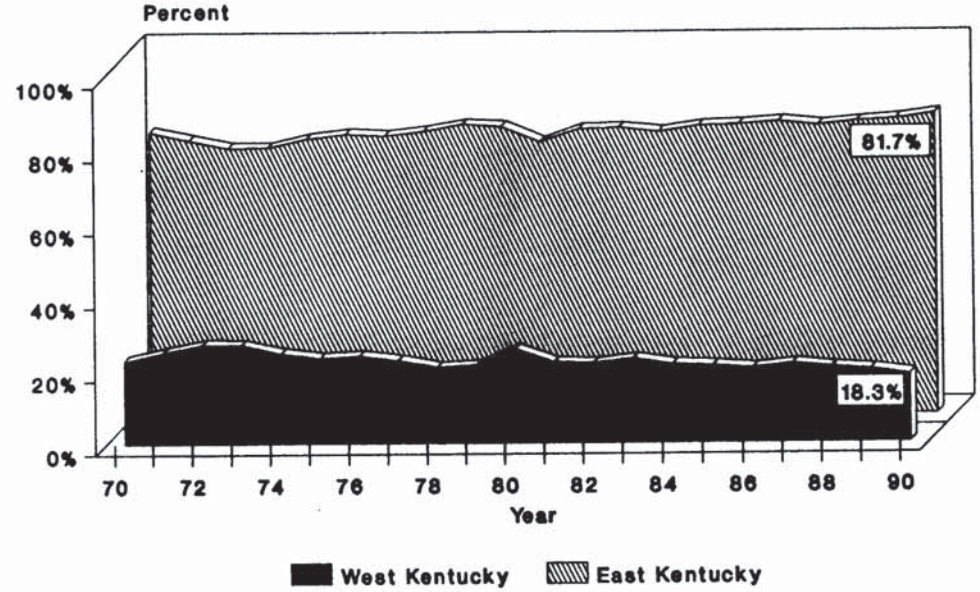
These relative shares of production and employment suggest that coal production in east Kentucky is more labor-intensive than that of west Kentucky. A review of productivity trends in Figure 7 supports this. Productivity has been consistently higher in west Kentucky. In 1990, productivity averaged 3.46 tons per miner per hour in west Kentucky coalfields, compared to 2.66 tons per miner per hour in east Kentucky. This productivity difference is mostly explained by the differences in the nature of the coal reserves. On average, coal seams in west Kentucky are thicker than those found in east Kentucky. Thicker seams are generally easier to mine.

Figure 5
Distribution of Kentucky Coal Production
1978-1990



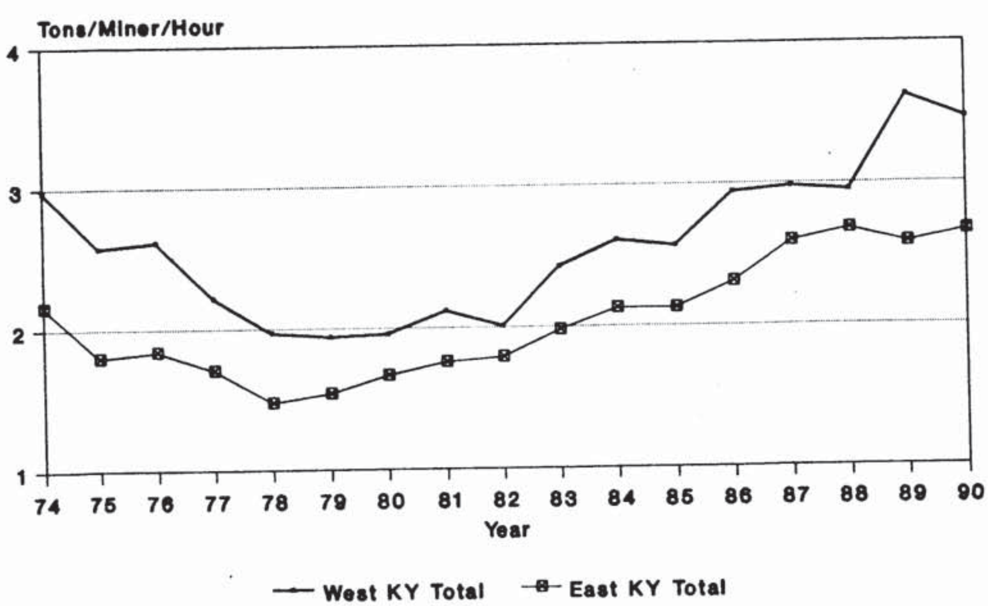
Source: Calculated by staff

Figure 6
Distribution of Kentucky Coal Employment
1970-1990



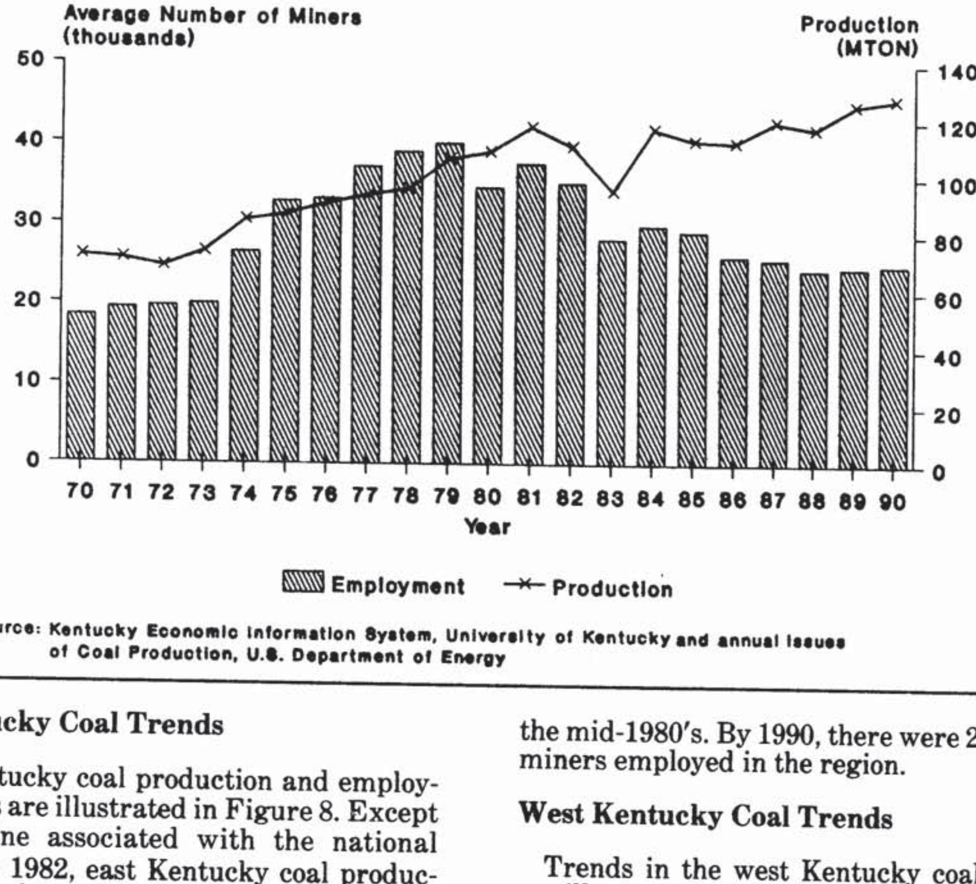
Source: Calculated by staff

Figure 7
Kentucky Coal Mining Productivity
By Coal Producing Region, 1974-1990



Source: Kentucky Economic Information System, University of Kentucky and annual issues of Coal Production, U.S. Department of Energy

Figure 8
East Kentucky Coal Mining Trends
1970-1990



Source: Kentucky Economic Information System, University of Kentucky and annual issues of Coal Production, U.S. Department of Energy

East Kentucky Coal Trends

East Kentucky coal production and employment trends are illustrated in Figure 8. Except for a decline associated with the national recession in 1982, east Kentucky coal production increased steadily, from 72.5 million tons in 1970 to 127.7 million tons in 1990, reflecting an average annual growth rate of 3.7 percent.

Coal-mining employment increased dramatically from 1970 to 1981. In 1970, there were an estimated 18,000 people employed in coal mining in east Kentucky. By 1981, there were approximately 37,500. However, as coal production decreased during the 1982-1983 recession, mining employment decreased as well.

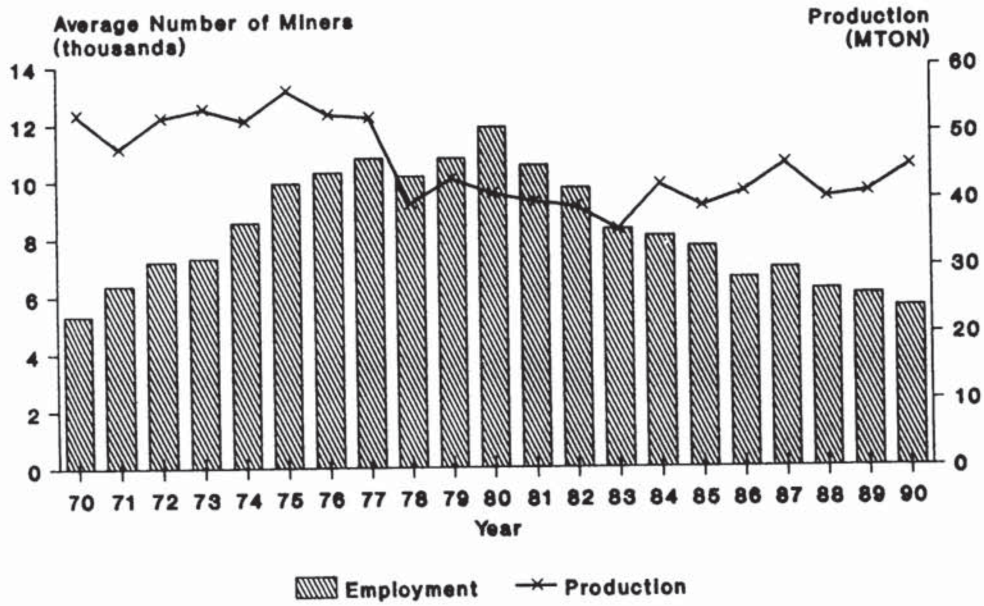
While the recession generated only temporary declines in production, this period marked a turning point in coal-mining employment. Coal-mining employment declined steadily in the mid-1980's. By 1990, there were 24,912 coal miners employed in the region.

West Kentucky Coal Trends

Trends in the west Kentucky coal industry are illustrated in Figure 9. West Kentucky coal production generally increased, from 52.8 million tons in 1970 to 56.4 million tons in 1975. However, production subsequently declined, to a low of 41.1 million tons in 1983. Production levels recovered slightly and reached 44.9 million tons by 1990, still well below levels of the mid-1970's.

Employment trends in west Kentucky coal mirrored those in east Kentucky. In 1970, there were an estimated 6,400 people employed in the industry. Employment reached a high of approximately 10,500 people in 1979, in spite of significantly reduced production levels that year. Beginning in 1979, coal-mining employment declined steadily, to 5,586 in 1990.

Figure 9
West Kentucky Coal Mining Trends
1970-1990



Source: Kentucky Economic Information System, University of Kentucky and annual issues of Coal Production, U.S. Department of Energy

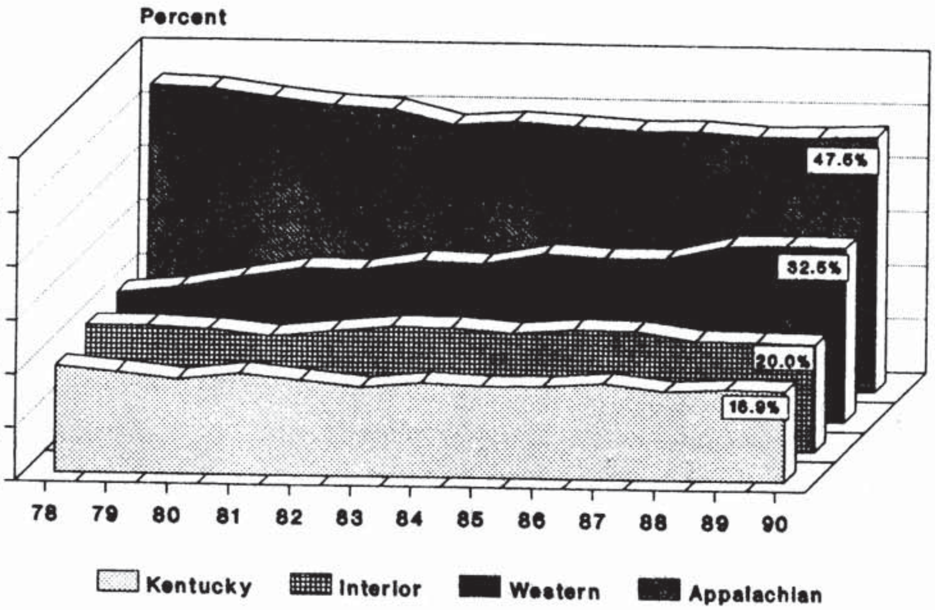
Kentucky's Place in National Coal Supply

Since Kentucky coal producers compete with producers in other states, a discussion of trends in the Kentucky coal industry is incomplete without an examination of how Kentucky coal production relates to the national coal market. From the early 1970's to 1987, Kentucky led the nation in coal production. However, Kentucky's share of U.S. coal production is declining. In 1978, Kentucky accounted for 19.9 percent of national coal production. This share declined to 16.9 percent in 1990, in spite of the fact that Kentucky coal production generally increased.

Kentucky's declining share of national coal production results primarily from increases in coal production in the western United States. Figure 10 illustrates trends in the share of national coal production in the three major coal-producing regions and in Kentucky. The Western region's share of national production increased from 22.4 percent in 1978 to 32.5 percent in 1990. Wyoming, the largest coal-producing state in the Western region, has experienced dramatic increases in coal production over the last twenty years. In 1970, Wyoming coal production totaled 7.2 million short tons. By 1990, production increased to 184.7 million short tons.[13]

Table 5 ranks coal production by state for 1987 to 1990. In 1987, more coal was mined in Kentucky than in any other state. However, by 1988 Wyoming became the nation's largest supplier of coal.

Figure 10
Regional Share of Total
U.S. Coal Production, 1978-1990



Source: Annual Issues of Coal Production, U.S. Department of Energy

Table 5
U. S. Coal Production Ranked by State
(Thousand Short Tons)

	1987		1988		1989		1990	
RANK	STATE	TONNAGE	STATE	TONNAGE	STATE	TONNAGE	STATE	TONNAGE
1	Kentucky	165,192	Wyoming	164,014	Wyoming	171,558	Wyoming	184,249
2	Wyoming	146,850	Kentucky	157,852	Kentucky	167,389	Kentucky	173,322
3	West Virginia	136,676	West Virginia	145,005	West Virginia	153,580	West Virginia	169,205
4	Pennsylvania	70,423	Pennsylvania	70,645	Pennsylvania	70,596	Pennsylvania	70,514
5	Illinois	59,155	Illinois	58,594	Illinois	59,267	Illinois	60,393
6	Texas	50,529	Texas	52,281	Texas	53,854	Texas	55,755
7	Virginia	44,543	Virginia	45,886	Virginia	43,006	Virginia	46,917
8	Ohio	35,788	Montana	38,881	Montana	37,742	Montana	37,616
9	Montana	34,399	Ohio	34,043	Ohio	33,689	Indiana	35,907
10	Indiana	34,208	Indiana	31,271	Indiana	33,641	Ohio	35,252
11	Alabama	25,540	North Dakota	29,731	North Dakota	29,566	North Dakota	29,213
12	North Dakota	25,142	Alabama	26,518	Alabama	27,992	Alabama	29,030
13	New Mexico	21,131	New Mexico	21,803	New Mexico	23,702	New Mexico	24,292
14	Utah	16,508	Utah	18,163	Utah	20,102	Utah	22,058
15	Colorado	14,420	Colorado	15,912	Colorado	17,123	Colorado	18,910
16	Arizona	11,379	Arizona	12,398	Arizona	11,935	Arizona	11,034
17	Tennessee	6,442	Tennessee	6,510	Tennessee	6,480	Tennessee	6,193
18	Washington	4,449	Washington	5,170	Washington	5,039	Washington	5,001
19	Missouri	4,292	Missouri	4,169	Missouri	3,378	Maryland	3,487
20	Maryland	3,962	Maryland	3,242	Maryland	3,376	Louisiana	3,186
21	Oklahoma	2,870	Louisiana	2,889	Louisiana	2,983	Missouri	2,647
22	Louisiana	2,751	Oklahoma	2,136	Oklahoma	1,753	Alaska	1,706
23	Kansas	2,021	Alaska	1,745	Alaska	1,582	Oklahoma	1,698
24	Alaska	1,492	Kansas	737	Kansas	856	Kansas	721
25	Iowa	468	Iowa	341	Iowa	430	Iowa	381
26	Arkansas	84	Arkansas	276	Arkansas	70	California	61
27	California	46	California	54	California	41	Arkansas	59
	U. S. Total	918,762	U. S. Total	950,266	U. S. Total	980,730	U. S. Total	1,029,076

Source: Coal Production 1989 and 1990, Energy Information Administration, U.S. Department of Energy

Factors Affecting Coal Markets

Coal Demand

Coal is used in the production of other goods. Therefore, coal demand is derived from the demand for the final-goods produced by using coal. There are four predominant sources of coal demand: 1) electric utilities, 2) coke plants, 3) exports, and 4) industry.

Electric utilities are the primary market for coal. Since coal is burned to generate steam for electricity generation, the demand for coal is derived from the demand for electricity. In 1990, 78 percent of coal produced in the United States was delivered to electric utilities (Figure 11). The utility market accounted for 95 percent of the west Kentucky coal market and 70 percent of the east Kentucky coal market.

The primary source of metallurgical grade coal is the northern and central Appalachian basin. Coking plants convert metallurgical grade coal to coke, which is then combined with iron ore to produce pig iron and steel. Therefore, the demand for metallurgical grade coal is dependent upon the demand for steel. Steel production in the United States declined significantly from 1970 to the early 1980's, which resulted in declining domestic demand for metallurgical coal.[14] In 1990, 3.7 percent of east Kentucky coal was shipped to domestic coking facilities, while less than one percent of west Kentucky coal was shipped to this market.

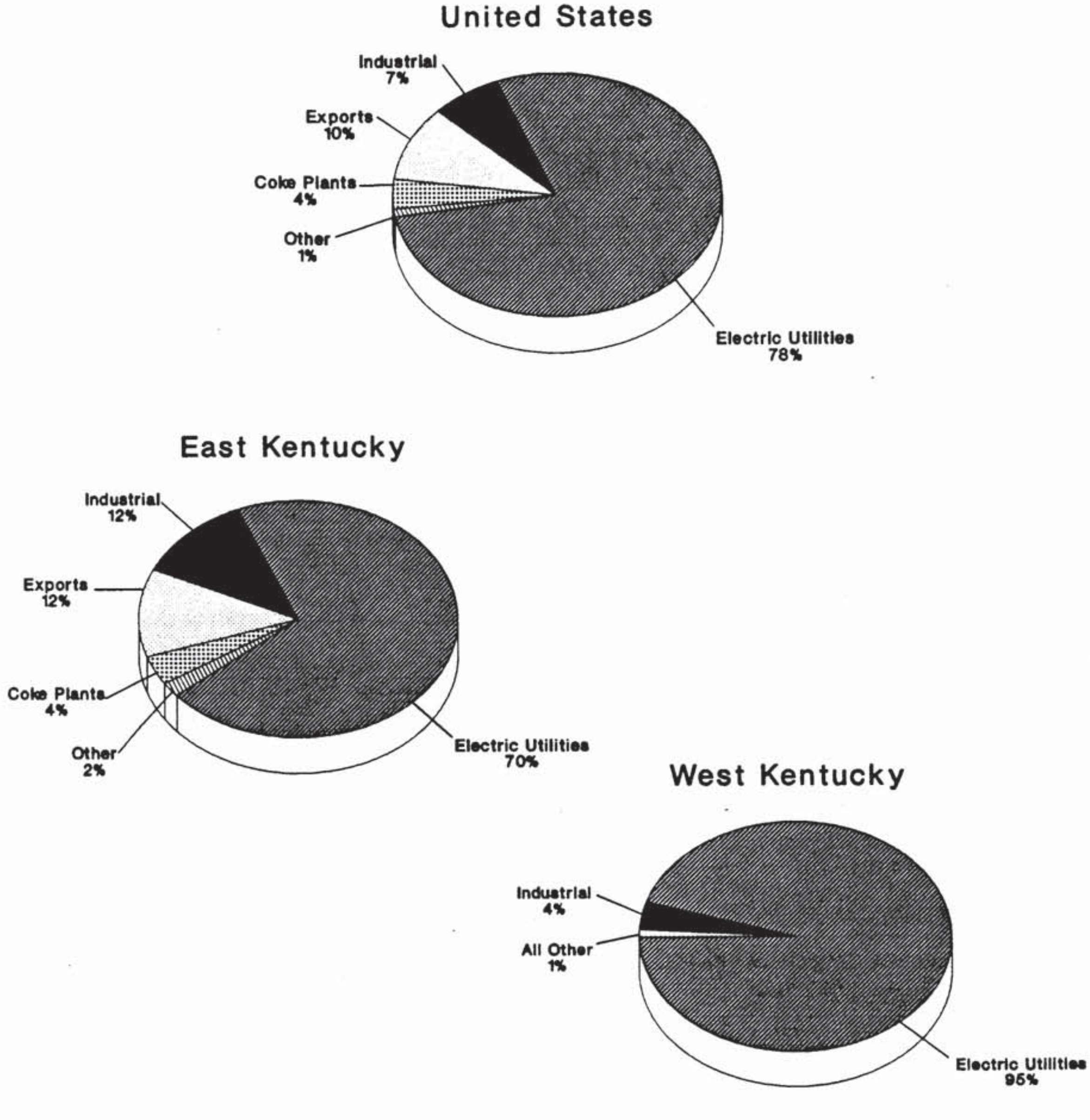
Export markets are considered a separate consumer segment, because the demand for US-produced coal is not only dependent on the economic outlook for the goods produced by using coal, but is also dependent on exchange rates, international trade policies, and international competition. Foreign markets account for less than one percent of the market for west Kentucky coal. East Kentucky coal, however, has a significant export market. In 1990, twelve percent of east Kentucky coal was exported.

There are two factors which contribute to the large export market for east Kentucky coal. Firstly, geographic location and transportation networks facilitate the movement of east Kentucky coal to ports on the Atlantic seaboard and in the Great Lakes area. Secondly, east Kentucky coal is generally low in sulfur content and high in heat content and meets the quality criteria demanded by export customers. (Coal quality as a determinant in coal demand is expanded upon in the next section.)

Coal is also used by industrial facilities for electricity generation, space heating, and processing of raw materials. Emissions from industrial facilities will also be affected by other provisions of the Clean Air Act Amendments. In 1990, twelve percent of east Kentucky coal was shipped to industrial sites. This segment accounted for only 4 percent of west Kentucky distributions for the same year.

By far, the primary source of demand for coal is electric utilities. While east Kentucky coal producers supply coal to a relatively diversified market, west Kentucky coal producers depend almost exclusively on electric utilities. Since the major focus of Title IV of the Clean Air Act Amendments is emissions from electric utilities, the remainder of this report will address factors affecting the electric utility market for Kentucky coal.

Figure 11
Market Distribution of Coal
Shipments, 1990



Source: Coal Distribution January-December 1990, U.S. Department of Energy

Coal Quality

A primary factor affecting the utility demand for coal is coal quality. There are three basic quality characteristics of coal: 1) heating capacity, 2) sulfur content, and 3) ash content. Coal quality varies greatly between the three major coal-producing regions. Table 6 summarizes coal quality data for coal delivered to electric utilities, by state of origin.

The heat content, measured in British Thermal Units (Btus), of coal is a primary factor affecting a utility's demand for coal. The higher the heating capacity, the less coal a utility will have to burn to generate a given amount of electricity.

Both coal-producing regions in Kentucky have coal high in heat content. In 1990, east Kentucky coal averaged 12,426 Btus per pound, while west Kentucky coal averaged 11,540 Btus per pound. The average heat content for both Kentucky regions exceeded the national average of 10,465 Btus per pound. Generally, coal from the Western region is low in Btus compared to that of Kentucky. Wyoming coal averaged 8,669 Btus per pound in 1990.

Ash and sulfur content in coal have been quality issues since the emission of their adverse by-products was restricted in the implementation of the Clean Air Act of 1970. When coal is burned, residual or particulate ash is formed. Prior to the Clean Air Act of 1970, particulates were often released to the atmosphere. However, these emissions have been reduced substantially over the last two decades through the use of technologies which capture the particulate ash. Nonetheless, the ash residual is a solid waste and must be properly disposed. The greater the ash residual, the higher the cost of waste disposal. In 1990, east Kentucky coal averaged 9.7 percent ash by weight, compared to 11.1 percent for west Kentucky coal.

Sulfur in coal is released when coal is burned and it combines with oxygen to create sulfur dioxide, which is then released to the atmosphere. Emissions can be minimized by burning low-sulfur coal, or by using clean coal technologies or flue gas desulfurization equipment (scrubbers). While sulfur emissions were limited in the 1970 Act and the Clean Air Act Amendments of 1977, additional restrictions are mandated by Title IV of the Clean Air Act Amendments.

Sulfur content of coal also varies by region. Within the Appalachian region, coal from the northern area is broadly characterized as high-sulfur, while central and southern area coal is considered low-to-medium in sulfur content. East Kentucky coal, in the central Appalachian region, averaged 1.07 percent sulfur by weight in 1990. Interior region coal is considered high in sulfur content. West Kentucky coal, part of the Interior region, averaged 3.21 percent sulfur in 1990. Western region coal is broadly characterized as low-sulfur. Wyoming coal averaged 0.38 percent by weight in 1990.

However, emissions limits are referred to in pounds of sulfur per million Btus. The potential sulfur emission for coal can be approximated by the following formula:[15]

$$\text{Pounds of Sulfur Dioxide per million Btus} = \frac{20{,}000 \text{ X (percent sulfur by weight)}}{\text{Btus per pound}}$$

On average, coal delivered to utilities from east Kentucky had potential emissions of approximately 1.73 pounds of sulfur per million Btus, while west Kentucky coal had average potential emissions of 5.73 pounds of sulfur per million Btus. Potential emissions of Wyoming coal averaged 0.88 pounds per million Btus.

If current coal production trends continue, much of the east Kentucky coal can be burned without the use of coal cleaning equipment during Phase I. However, in absence of clean coal technologies, much smaller amounts of coal will meet these standards during Phase II (See Appendix B).

Electricity generating units are designed with specifications as to the quality of the coal to be burned. In order to burn coal that is significantly different in quality (Btu or Ash) than originally designed, units must undergo modifications. These modifications, called derating, require capital investments and will increase the relative cost of coal switching.

The extent to which east Kentucky can supply coal which will meet the Phase II standards

Table 6

Coal Quality Statistics for Coal-Producing States, 1990

Coal-Producing Region & State	Shipments to Utilities (1000 short tons)	Average Quality Btu (per pound)	Average Quality Sulfur (% by weight)	Average Quality Ash (% by weight)	Approximate Pounds Sulfur Dioxide per Million Btu*
Appalachian Region					
Alabama	16,383	12,190	1.34	12.39	2.20
Kentucky, East	85,199	12,426	1.07	9.70	1.72
Maryland	3,004	12,612	1.61	12.62	2.55
Ohio	30,103	11,717	3.34	11.28	5.70
Pennsylvania	50,488	12,366	1.82	12.75	2.94
Tennessee	4,618	12,623	1.44	9.87	2.28
Virginia	17,366	12,951	1.14	9.42	1.76
West Virginia	88,608	12,524	1.64	10.68	2.62
Interior Region					
Illinois	54,232	11,179	2.71	9.54	4.85
Indiana	30,899	11,104	2.55	9.26	4.59
Iowa	66	10,128	3.33	11.76	6.58
Kansas	650	12,074	3.14	12.02	5.20
Kentucky, West	43,619	11,540	3.21	11.10	5.56
Louisiana	3,186	6,881	0.55	12.50	1.60
Missouri	2,343	10,570	4.18	10.05	7.91
Oklahoma	917	12,417	1.77	9.63	2.85
Texas	49,086	6,332	1.00	16.39	3.16
Western Region					
Arizona	11,447	11,015	0.50	9.17	0.91
Colorado	15,382	10,694	0.41	8.67	0.77
Montana	35,627	9,012	0.53	7.09	1.18
New Mexico	22,644	9,349	0.70	19.47	1.50
North Dakota	22,983	6,586	0.82	9.19	2.49
Utah	15,237	11,592	0.50	10.17	0.86
Washington	4,696	8,104	0.73	15.33	1.80
Wyoming	176,478	8,669	0.38	5.61	0.88
Kentucky Total	128,818	12,126	1.80	10.19	2.97
U.S. Total	785,261	10,462	1.35	9.86	2.58

*Calculated by staff, approximate pounds of SO_2 = (20,000 X % sulfur by weight)/Btu per pound

Source: Cost and Quality of Fuels for Electric Utility Plants 1990, Energy Information Administration, U.S. Department of Energy

(in lieu of use of coal-cleaning equipment) will depend on the availability of low-sulfur reserves. In a 1982 study, the Kentucky Geological Survey (KGS) estimated low-sulfur coal (defined as having potential emissions of 1.2 pounds per million Btus or less) resources in Kentucky.[16] Coal resources are defined as the total amount of coal in the ground without accounting for mineability or recoverability. The KGS study estimated that 43 percent of the eastern Kentucky coal resources was low-sulfur coal. This compares to earlier estimates of 35 percent for east Kentucky. (In this report, it was estimated that 25% of west Kentucky coal was compliance coal.) Therefore, production of low-sulfur coal may be limited by the availability of low-sulfur resources.

The quantity and quality of coal supplied is responsive to the market forces of coal demand and price. As the demand for low-sulfur coal increases, prices will also increase. This may improve the economic feasibility of mining low-sulfur coal reserves.

Coal Prices

The key factors affecting the demand for coal by utilities are the price of electricity, the price of coal, and the price of coal substitutes. In general, the lower the price of a commodity, the higher the demand. Therefore, the price determines how much coal utilities are willing to purchase. Similarly, price is the key factor which determines how much coal an operator will be willing to produce. The higher the price, the greater the incentive to produce coal.

Figure 12 illustrates minemouth price trends for United States, Kentucky, east Kentucky, and west Kentucky coal. The minemouth price of coal increased dramatically from 1973 to 1981. These price increases reflect national trends and resulted primarily from strong growth in the domestic demand for electricity. The OPEC oil embargo of 1973 and the Iranian revolution in the late 1970's resulted in rising oil prices and market uncertainty. These factors prompted utilities to switch to coal, which was cheaper. This increased demand pushed coal prices higher. In the mid-1980's, oil-producing nations in the Middle East sought to regain their shares of the world energy market and oil prices dropped. This development, combined with competition within the industry, forced coal producers to reduce coal prices.

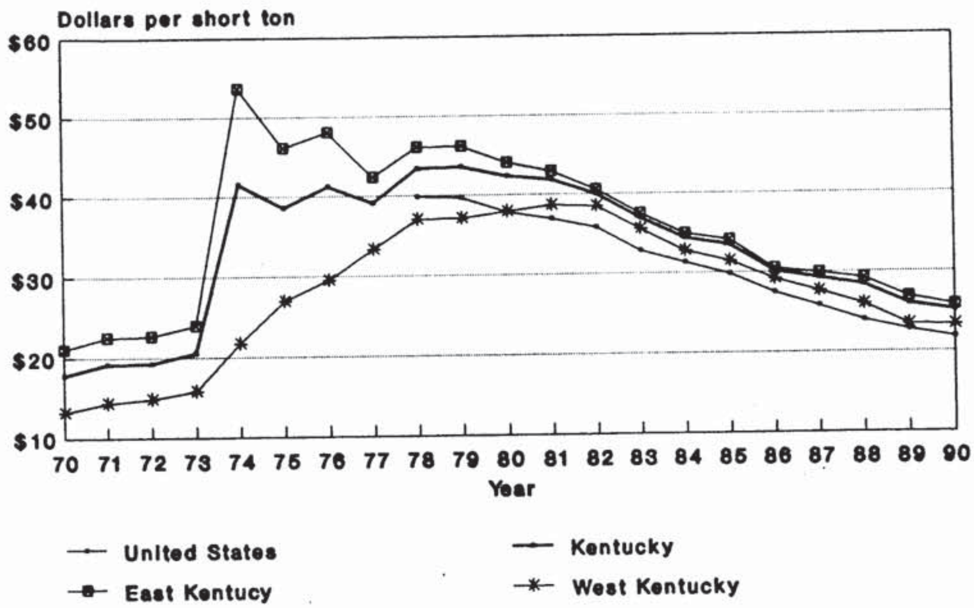
Average mine prices of coal for coal-producing states in 1990 are summarized in Table 7. The average mine price of east Kentucky coal was $26.44 per short ton, compared to $22.01 per short ton for west Kentucky coal. These prices are slightly higher than the national average of $21.76. However, the average mine price of coal produced in the Western Region was $11.60 per short ton, significantly less than either the national average or Kentucky prices. Wyoming coal, the largest source of coal in the Western Region, averaged only $8.43 per short ton.

A primary factor in the differences in minemouth prices is differences in productivity. Nationally, average productivity was 3.87 tons/miner/hour (Table 7). However, productivity for Wyoming was 21.41 tons/miner/hour, compared to 2.83 tons/miner/hour for Kentucky. The bulk of Wyoming coal is extracted by surface mining methods, which is generally more productive than underground mining. This factor, combined with very thick coal seams and a flatter topography, facilitates the easier extraction of coal. The results are higher levels of productivity, lower production costs and, ultimately, lower minemouth coal prices.

While mine price reflects the price received by coal mine operators, the average delivered cost reflects the cost of coal to the utilities. Average delivered cost includes the mine price of the coal, as well as processing and transportation cost. The average delivered cost of coal to electric utilities is also listed in Table 7. In 1990, the average delivered cost for coal delivered to electric utilities in the United States was $30.45 per short ton. The average delivered cost for east Kentucky coal was higher, at $41.73 per short ton. The average delivered cost of west Kentucky coal, $28.93 per short ton, was slightly lower than the national average.

Since Btu varies for coal, the best price for comparison is the cost per Btu. In 1990, the delivered cost of east Kentucky coal averaged $1.68 per million Btus, compared to $1.25 per million Btus for west Kentucky coal.

Figure 12
Average Minemouth Price, 1970-1990
(1990 Dollars)



Source: Annual Issues of Coal Production, U.S. Department of Energy

The cost differential of coal from the two regions is primarily explained by differences in distance of transport and coal quality.

While the mine price of coal from the Western Region was significantly less than that of Kentucky coal, the average delivered cost per million Btus was much closer to that of Kentucky coal. In 1990, cost per Btu for Wyoming coal was $1.33 per million Btus.

In summary, there are three major factors which will influence a utility's strategy for compliance with the CAAAs: (1) the sulfur content of coal; (2) the heating capacity of coal, and (3) the delivered cost of coal. Utilities which buy west Kentucky coal will have to use either coal-cleaning or emissions cleaning technologies. The lower average delivered cost of west Kentucky coal may make this a least-cost strategy for many utilities.

There has been a great deal of debate on the competitiveness of east Kentucky coal as it compares to coal from the western United States, particularly Wyoming. While on a per ton basis Wyoming coal is lower in sulfur content, it is also lower in heating capacity. Therefore, factors which affect minemouth prices and transportation costs, and thus delivered cost, will be critical in determining east Kentucky coal's competitiveness.

Table 7
Average Prices of Coal for Coal-Producing States, 1990

Coal-Producing Region & State	Shipments to Utilities (1000 short tons)	Average Mine Price (dollars per short ton)	Average Delivered Cost (cents per million Btu)	Average Delivered Cost (dollars per short ton)	Productivity (tons per miner per hour)
Appalachian Region	295,769	28.89	NA	NA	2.6
Alabama	16,383	43.04	203.5	49.61	2.23
Kentucky, East	85,199	25.84	168.6	41.73	2.66
Maryland	3,004	25.97	152.9	38.57	2.93
Ohio	30,103	28.65	139.2	34.57	2.80
Pennsylvania	50,488	30.15	154.8	38.28	2.24
Tennessee	4,618	27.96	144.3	36.42	1.81
Virginia	17,366	28.05	168.7	43.70	2.24
West Virginia	88,608	28.62	157.7	39.50	2.96
Interior Region	184,998	21.45	NA	NA	3.88
Illinois	54,232	27.73	158.2	35.37	2.94
Indiana	30,899	23.91	127.8	28.38	3.84
Iowa	66	w	163.7	33.17	1.45
Kansas	650	w	123.0	29.70	2.03
Kentucky, West	43,619	23.32	121.9	28.12	3.46
Louisiana	3,186	w	133.5	18.37	13.16
Missouri	2,343	w	150.8	31.87	2.99
Oklahoma	917	30.39	139.2	34.57	2.08
Texas	49,086	11.20	108.4	13.73	7.48
Western Region	304,494	11.60	NA	NA	11.82
Arizona	11,447	w	107.9	23.76	5.93
Colorado	15,382	21.75	143.1	30.60	4.24
Montana	35,627	9.42	136.8	24.66	18.78
New Mexico	22,644	22.43	150.4	28.13	7.64
North Dakota	22,983	7.67	72.4	9.54	16.72
Utah	15,237	18.53	118.5	27.46	4.74
Washington	4,696	w	160.0	25.93	3.41
Wyoming	176,478	8.43	132.7	23.01	12.41
Kentucky Total	128,818	25.19	154.3	37.43	2.83
U.S. Total	785,261	21.76	145.5	30.45	3.83

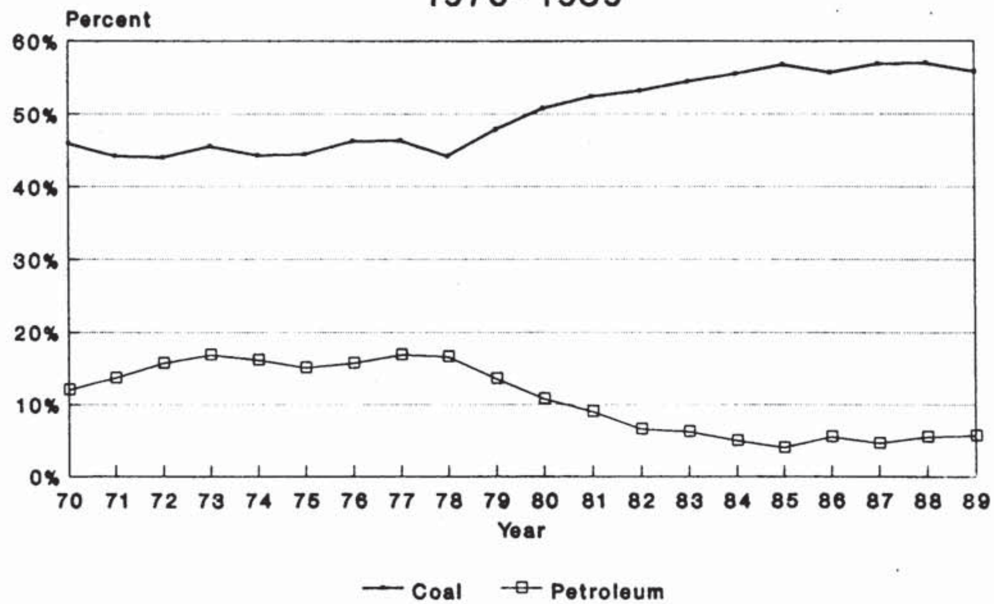
w=withheld
NA=Not Available
Source: Coal Production 1990 and Cost and Quality of Fuels for Electric Utility Plants 1990, Energy Information Administration, U.S. Department of Energy

The Electric Utility Market

Coal has gained a larger share of the electric utility market in the United States over the last decade. The share of electricity generated from coal increased from 44 percent in 1978 to 55 percent in 1989 (Figure 13). This increase was due to both an increase in the quantity of coal used and a decline in the quantity of oil used.

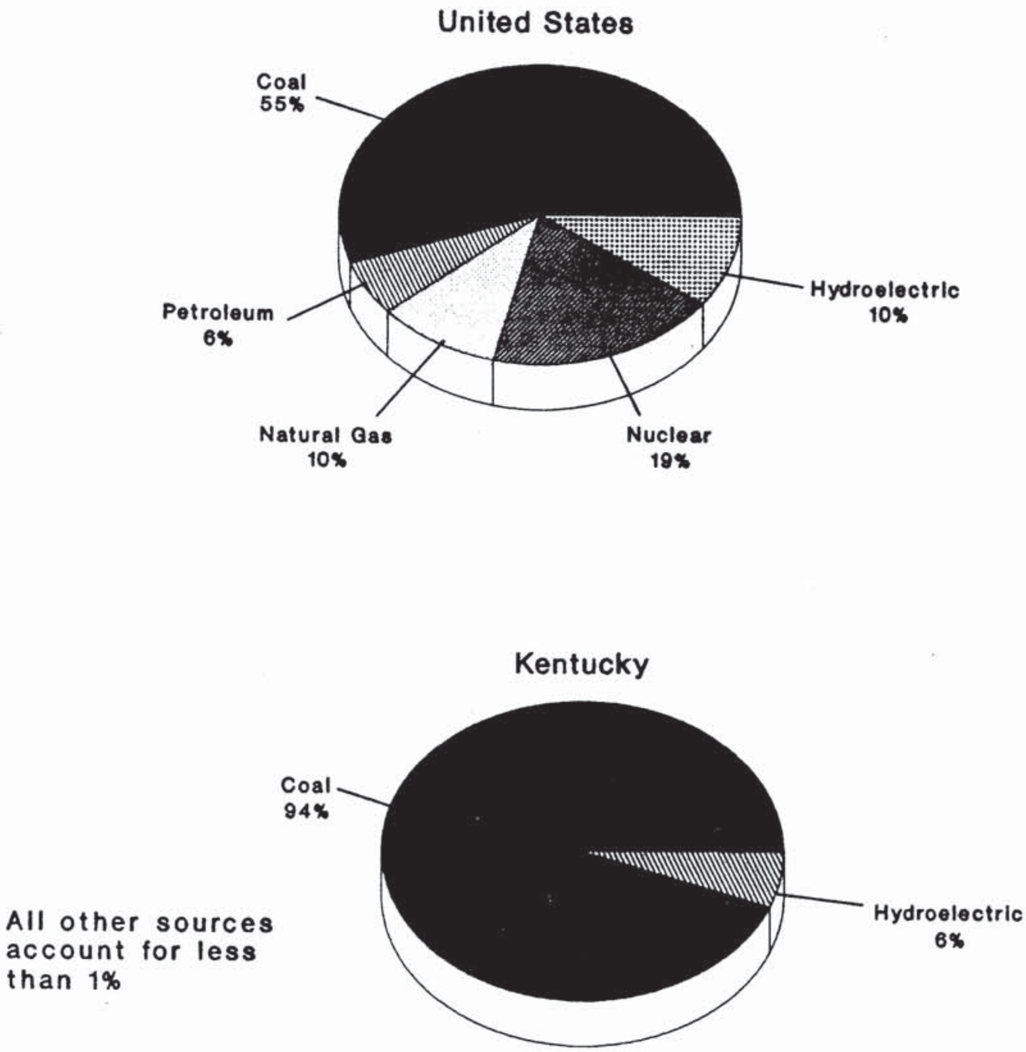
Figure 14 illustrates the share of electricity generation by energy source in 1989 for Kentucky and the United States. At the national level, coal was the largest contributor to electric utility supply, compared to 19 percent for nuclear energy, 10 percent for hydroelectric power, 10 percent for natural gas, and 6 percent for petroleum.

Figure 13
Share of Electricity Generated from Coal and Petroleum in the United States
1970-1989



Source: Kentucky Economic Information System, University of Kentucky and annual issues of Annual Energy Review, U.S. Department of Energy

Figure 14
Share of Net Generation by Energy Source, 1989



Source: Electric Power Annual, 1989, U.S. Department of Energy

Coal accounts for a much larger share of electricity generation in Kentucky than in the nation. In 1989, coal accounted for 94% of electricity generation in Kentucky. The second largest source of generation was hydroelectric power, which accounted for approximately 6%. Petroleum and natural gas account for less than one percent , while there was no nuclear generation in the state.

Kentucky Coal and the Electric Utility Market

In 1990, 85.2 million short tons of eastern Kentucky coal was delivered to electric utilities in 25 states (Table 8). However, eight states account for 86.1 percent of the total shipments. Georgia utilities were the top purchasers and accounted for 15.8 percent of total shipments. Utilities in Kentucky ranked 4th in receipt of east Kentucky coal, receiving 9.5 million short tons, or 11.1 percent of total utility shipments.

Since east Kentucky coal is generally low-to-medium in sulfur content, these markets are not expected to be affected by Phase I of the CAAAs. It is uncertain how these markets will be affected by Phase II.

Since there is less coal produced in west Kentucky than east Kentucky, it is not surprising that west Kentucky supplies coal to fewer states. In 1990, approximately 43.6 million short tons of west Kentucky coal was delivered to electric utilities in thirteen states (Table 9). Utilities in Kentucky were by far the largest market for west Kentucky coal, receiving 18.8 million short tons, or 43 percent of total shipments to utilities. Moreover, four states accounted for 84.6 percent of the west Kentucky utility market.

In a report issued by the Governor's Office for Coal and Energy Policy, it was estimated that 15% of west Kentucky coal was sold to targeted Phase I units in Kentucky in 1989. An additional 43% was sold to targeted Phase I units in other states. If the utilities operating these units decide to switch to lower-sulfur coal rather than to use coal-cleaning technologies, these markets could be lost.

Table 10 summarizes the origin of coal received by utilities in Kentucky. Kentucky coal accounted for 80.5 percent of coal receipts. Of this, 53.6 percent of total coal receipts was from the west Kentucky coal region and 26.9 percent was from the east Kentucky coal region. West Virginia was the third largest supplier to Kentucky utilities, accounting for 8.9 percent of coal receipts, while Indiana coal accounted for 7.2 percent of utility receipts. Coal delivered from east Kentucky and West Virginia was relatively low in sulfur content, while the coal from west Kentucky and Indiana was relatively high in sulfur.

Table 8
States Ranked by Receipt of East Kentucky Utility Coal, 1990

	Receipts (thousand short tons)	Percent of EKY Market	Average Quality			Average Delivered Cost	
			Btu (per pound)	Sulfur (% by weight)	Ash (% by weight)	(cents per million Btu)	(dollars per short ton)
Georgia	12,616	14.81%	12,268	1.37	10.7	170.8	41.91
Florida	10,087	11.84%	12,718	0.96	8.2	184.3	46.87
North Carolina	9,670	11.35%	12,551	0.99	8.8	182.7	45.88
Kentucky	9,471	11.12%	12,187	1.03	10.8	131.7	32.09
Ohio	9,396	11.03%	11,859	1.14	12.7	156.1	37.02
South Carolina	8,145	9.56%	12,597	1.17	9.3	173.5	43.71
Michigan	7,242	8.50%	12,681	0.93	8.4	177.0	44.88
Tennessee	6,720	7.89%	12,063	1.26	11.1	151.6	36.58
Virginia	2,701	3.17%	12,697	1.05	8.6	157.0	39.87
Mississippi	2,138	2.51%	12,765	0.84	7.8	179.0	45.69
Illinois	1,436	1.69%	13,199	0.67	6.2	172.3	45.48
Alabama	1,351	1.59%	12,535	0.98	9.1	143.6	35.99
Connecticut	954	1.12%	13,233	0.54	6.4	212.9	56.35
Indiana	945	1.11%	12,588	0.71	8.5	213.1	53.65
West Virginia	753	0.88%	12,357	0.93	9.1	181.1	44.75
New York	659	0.77%	13,290	0.52	6.9	211.2	56.13
Maryland	407	0.48%	12,942	0.73	7.9	159.6	41.30
Wisconsin	196	0.23%	12,894	0.84	8.1	177.9	45.87
Delaware	117	0.14%	12,837	0.67	7.2	193.9	49.79
Pennsylvania	50	0.06%	12,710	1.26	8.7	177.7	45.16
Massachusetts	49	0.06%	12,598	0.94	8.7	179.9	45.33
New Jersey	47	0.06%	13,051	0.75	7.6	190.1	49.61
Missouri	23	0.03%	14,128	0.63	5.6	212.8	60.12
New Hampshire	17	0.02%	12,968	0.88	6.6	201.2	52.20
Minnesota	8	0.01%	12,105	1.10	9.8	188.5	45.65
Total (Averages)	85,199	100.00%	12,426	1.07	9.7	168.1	41.78

Source: Cost and Quality of Fuels for Electric Utility Plants 1990, Energy Information Administration, U.S. Department of Energy

Table 9
States Ranked by Receipt of West Kentucky Utility Coal, 1990

	Receipts (thousand short tons)	Percent of WKY Market	Average Quality			Average Delivered Cost	
			Btu (per pound)	Sulfur (% by weight)	Ash (% by weight)	(cents per million Btu)	(dollars per short ton)
Kentucky	18,830	43.17%	11,185	3.70	13.4	111.3	24.91
Tennessee	9,186	21.06%	11,763	2.64	8.7	127.6	30.02
Florida	5,249	12.03%	12,277	2.90	8.6	166.0	40.75
Indiana	3,647	8.36%	11,493	3.44	11.2	105.3	24.21
Alabama	2,064	4.73%	11,759	3.03	10.4	129.2	30.38
Georgia	1,842	4.22%	11,827	2.90	10.3	130.0	37.85
Missouri	1,043	2.39%	11,316	2.99	10.7	119.6	27.06
Illinois	757	1.74%	11,576	1.73	8.2	120.5	27.90
Mississippi	629	1.44%	11,890	2.61	6.9	144.4	34.34
Ohio	266	0.61%	11,373	2.39	9.8	136.2	30.97
Michigan	50	0.11%	11,678	2.99	10.1	140.5	32.81
Iowa	29	0.07%	11,218	3.09	11.2	133.2	29.88
West Virginia	25	0.06%	11,935	3.47	12.7	129.9	31.01
Total (Averages)	43,619	100.00%	11,540	3.21	11.1	125.3	28.93

Source: Cost and Quality of Fuels for Electric Utility Plants 1990, Energy Information Administration, U.S. Department of Energy

Table 10

Origin of Coal Received by Utilities in Kentucky, 1990

	Quantity (short tons)	Percent of Total	Sulfur (% by weight)
Illinois	91	0.3%	1.84%
Indiana	2,525	7.2%	2.67%
Kentucky			
East	9,471	26.9%	1.07%
West	18,830	53.6%	3.21%
Ohio	251	0.7%	2.76%
Pennsylvania	12	<0.1%	2.43%
Tennessee	626	1.9%	2.61%
Virginia	60	0.2%	0.81%
West Virginia	3,073	8.7%	0.77%
Wyoming	213	0.6%	0.35%
Total (average)	35,151		2.59%

Source: Cost and Quality of Fuels for Electric Utility Plants 1990, Energy Information Administration, U.S. Department of Energy

Summary

The Kentucky coal mining sector has undergone significant adjustments over the last two decades. These changes have been propelled by increases in productivity. While coal production increased over the last ten years, coal mining employment declined. These adjustments have been in response to events in international energy markets, as well as increasing competitiveness among coal producers.

Coal demand by electric utilities depends on the demand for electricity. However, compliance with the CAAAs requires that utilities consider both coal quality and coal prices when deciding if and where to purchase coal. While west Kentucky coal is high in sulfur content, it is also high in heating capacity and relatively low in price. It is estimated that 58% of west Kentucky coal is sold to units affected by the CAAAs. The continued demand for west Kentucky coal by these utilities will depend on the expected future price of electricity, future delivered costs of coal and the costs associated with technological options for reducing sulfur dioxide.

East Kentucky coal is generally low-to-medium in sulfur content and is high in heating capacity. However, it is also relatively higher in price. Therefore, the continued competitiveness of east Kentucky coal will depend on the delivered price of east Kentucky low-sulfur coal, compared to other low-sulfur fuel options. Future advances in precombustion removal of sulfur may also increase the competitiveness of east Kentucky coal.

CHAPTER IV

ECONOMIC IMPACT OF TITLE IV OF THE CLEAN AIR ACT AMENDMENTS OF 1990

There is a variety of potential economic effects of Title IV of the Clean Air Act Amendments of 1990.[17] However, the purpose of this analysis is to focus on private-sector effects related to utility compliance with Title IV provisions and changes in the coal markets. Changes in utility demand for coal are expected to result in substantial shifts in regional coal production. These shifts will have profound impacts on the economies of the coal-producing regions.

The first step in economic impact analysis is identifying the projected employment, production, and costs related directly to the pending action, or the direct effects. These changes generate indirect and induced effects, which result from linkages in the state and regional economy. Linkages involve purchases by both producers and employees. In the coal sector, companies purchase coal-mining equipment, supplies, and services. These are called the indirect effects. Miners and their families spend earnings on consumption items, such as housing, food, clothing, appliances, and entertainment. These are called the induced effects; they generate employment in other supplier businesses. Successive rounds of spending generate further economic impacts. Also, increased savings provide a larger pool of financial reserves which can be invested in new projects. The total economic impact of a particular industry will depend on the nature of the industry and the strength of these economic linkages.

Similarly, the change in electricity rates will also generate economic effects when electricity consumers adjust their budgets and production processes to the higher rates. For example, an electricity intensive manufacturing facility will incur higher production costs. Eventually, electricity consumers will respond to higher electric rates by reducing electricity consumption and becoming more energy efficient.

In many types of impact analyses the direct impacts are known, such as the number of people to be employed, average wage rates, and the investment the firm is making. In the case of the CAAAs, we have to make assumptions regarding coal supplies and future compliance strategies. Therefore, the direct effects can only be estimated.

The Direct Kentucky Coal Market Effects of the CAAAs

The Energy Information Administration (EIA), an independent statistical and analytical agency within the U.S. Department of Energy, gathers data on energy resources and markets. This data is used to develop and maintain a variety of interactive models of energy markets, including models of coal reserves, coal markets, and utility markets. This is a detailed modeling system in which coal demands in 44 regions are met via transportation networks from existing mines in 32 supply regions. On the demand side, this system incorporates data on nonutility demand, and electricity generation and transmission, capital and operating cost of utilities, flue gas desulfurization equipment, and emissions for each generating unit of a utility. On the supply side, the model includes data on coal production, coal quality, supply-price relationships, coal reserves, and mining costs.

In any forecasting model, there are basic assumptions made regarding future events and behavior. These assumptions are critical to the accuracy of the forecasts. Several assumptions made regarding the strategies utilities will use to comply with the CAAAs are crucial to EIA's projections for Kentucky. One of these assumptions relates to long-term coal-supply contracts. The EIA utilized data on existing long-term contracts to project future coal production. Recent news accounts have indicated that production in the Kentucky coal fields currently exceeds demand. This is evidenced by recent reports of mine layoffs. However, it has also been suggested that west Kentucky coal producers are already experiencing declines in demand due to utilities planning for the CAAAs. To the extent that this is already occurring and utilities are able to extricate themselves from existing long-term contracts, the effects of the CAAAs on west Kentucky coal production may be realized sooner than EIA projects.

Secondly, there has been much debate as to the availability of low-sulfur coal reserves in east Kentucky. The Energy Information Administration based its projections of low-sulfur coal supplies on data from the Demonstrated Reserve Base, the national inventory of coal reserves. The accuracy of this data base is critical to the projections of east Kentucky coal production and coal prices. In telephone conversations, Dr. Richard Newcombe of that agency agreed that there is a great deal of controversy as to the availability of low-sulfur coal in the Appalachian coal fields. If the quantity of those reserves is overstated, the projected positive effects of the CAAAs on eastern Kentucky production is overstated. If the low-sulfur reserves are understated, price effects would be less.

Thirdly, while EIA projections are based on detailed data for individual utilities, existing transportation networks, and supplying mines, they assume a cost-minimizing approach to utility compliance. In the event that utilities consider other factors in their decisions, these factors will not be included in the EIA analysis.

The factors underlying the EIA projections also include forecasts of US economic performance and the outlook for energy markets. Among the many factors that influence the coal projections are assumptions of economic growth, inflation, electricity demand, and prices. Table 11 summarizes a few of EIA's assumptions for the period in this study.

Nationally, coal production is projected to increase by 1.3 percent per year in the 1990's. However, from the years 2000 to 2010, coal production is projected to increase by 2.8 percent. Prior to the year 2000, increases in electric utility demand for coal comes from fuller utilization of existing coal-fired capacity. However, after the year 2000 it is projected that additional generating units will be needed to meet electricity demand, resulting in increased demand for coal.

Minemouth coal prices are also projected to rise, recovering from a general decline that started in 1978. Increases in coal mine productivity is expected to level off, and excess production capacity should dissipate.

Mine output in low-sulfur coal regions is expected to increase more strongly than in high-sulfur coal regions in the 1990's. However, after 2000, the demand for high-sulfur coal should rebound, as more new coal-fired plants are constructed using either scrubbers or clean coal technologies.

At the request of the Legislative Research Commission, the EIA prepared an analysis of the impacts of the Clean Air Act Amendments on Kentucky coal production, coal prices, and average prices of coal received by electric utilities in Kentucky. The effects of the CAAAs on Kentucky coal production and prices were estimated by comparing production and prices under two forecast scenarios. The first scenario, the EIA reference case, included the provisions of the CAAAs. The second scenario assumed the CAAAs were not passed. The differences between the two projections are the estimated effects of the CAAAs.

Table 11
Assumptions Underlying Energy Information Administration Projections

	1989	1990	2010
Economic Indicators			
Real Gross National Product			
(billion 1982 dollars)	4,118	4,153	6,436
(annual change, 1989–2010)			2.1%
GNP Implicit Price Deflator			
(index, 1982=1.0)	1.263	1.314	2.909
(annual change, 1989–2010)			4.1%
Real Disposable Personal Income			
(billion 1982 dollars)	2,869	2,891	4,129
(annual change, 1989–2010)			1.7%
Energy Prices			
(1990 dollars)			
World Oil Price			
(dollars per barrel)	18.81	22.00	34.20
(annual change, 1989–2010)			2.9%
Domestic Coal Minemouth			
(dollars per short ton)	22.70	22.18	31.64
(annual change, 1989–2010)			1.6%
End–Use Prices			
(1990 cents per kilowatthour)			
Residential	8.22	8.10	8.68
(annual change, 1989–2010)			0.3%
Commercial/Other	7.82	7.67	7.66
(annual change, 1989–2010)			–0.1%
Industrial	5.22	5.12	5.67
(annual change, 1989–2010)			0.4%
Total	7.05	6.94	7.22
(annual change, 1989–2010)			0.1%
Coal Production			
(million short tons)			
East of Mississippi	599	638	869
(annual change, 1989–2010)			1.8%
West of Mississippi	382	397	623
(annual change, 1989–2010)			2.4%
Total	981	1,035	1,492
(annual change, 1989–2010)			2.0%

Source: Annual Energy Outlook, 1991, Energy Information Administration, US Department of Energy

Coal Production

The EIA projects that the effects of the CAAAs on Kentucky coal production will be positive at the beginning of Phase I and negative during Phase II. In 1995, Kentucky coal production is expected to total 195.43 million short tons, of which an increase of 4.33 million short tons are due to the CAAAs (Table 12). However, by the year 2000, total coal production is expected to decline to 189.85 million short tons. The estimated impact of the CAAAs on state production for that year is a loss of 12.58 million short tons. This represents six percent decline in what production would have been without the implementation of the CAAAs. However, by the year 2010 total Kentucky production is projected to increase to 232.72 million short tons. Despite this increase, the CAAAs are estimated to account for a loss of 11.92 million short tons in total Kentucky coal production.

In western Kentucky the major impacts of the CAAAs on coal production are projected to occur in the later part of the 1990's and in the next decade. In fact, it is projected that there will be a slight, short-lived increase in west Kentucky coal production due to the CAAAs in 1995, with a significant decline occurring in the year 2000.

Western Kentucky coal production is projected to total 49.44 million short tons in 1995. This includes approximately 570,000 short tons above what production levels would be without the CAAAs. This projected increase is a short-lived phenomena and reflects two factors. First, utilities which install scrubbers are assumed to increase their purchases of coal in order to meet the increased energy requirements of operating these scrubbers. A second factor considered by EIA in its projections was existing long-term supply contracts. The EIA has data on current contracts, supplying

Table 12
Projected Kentucky Coal Production & Impacts of the Clean Air Act Amendments (CAAAs) of 1990: 1995, 2000, 2005, 2010
(million of short tons per year)

	1995			2000		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	142.23	145.99	3.76	146.55	153.56	7.01
West Kentucky	48.87	49.44	0.57	55.88	36.29	-19.59
Kentucky Total	191.10	195.43	4.33	202.43	189.85	-12.58

	2005			2010		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	163.79	170.71	6.92	182.54	186.13	3.59
West Kentucky	58.60	40.88	-17.72	62.10	46.59	-15.51
Kentucky Total	222.39	211.59	-10.80	244.64	232.72	-11.92

Source: Energy Information Administration, Coal Data Analysis and Forecasting Division companies, tonnage, and duration of contract. They have assumed that these contracts will be honored and supplies will be met with deliveries from mines currently meeting these contracts.

However, as the long-term contracts expire, it is assumed that utilities will switch to other coal suppliers, and production in western Kentucky is projected to decline dramatically. In the year 2000, west Kentucky coal production is expected to total 36.29 million short tons. The CAAAss are estimated to result in a loss of 19.59 million short tons in that year, a 35 percent decline.

During the years 2001 to 2010, the EIA projects that west Kentucky coal production will rebound moderately. It is expected that new electricity generating units will be constructed, in order to meet increased electricity demand. This is expected to lead to a slight increase in demand for high-sulfur coal, as these new units are equipped with clean coal technologies and scrubbers. Therefore, after the year 2000, west Kentucky coal production is expected to increase from 36.29 million short tons in 2000 to 46.59 million tons by 2010. However, this production level is estimated to be 15.51 million short tons (or 25 percent) less than it would have been if the CAAAs of 1990 were not in affect.

East Kentucky coal production is projected to increase due to the CAAAs through the year 2010. In 1995, east Kentucky coal production is expected to total 145.99 million short tons, of which 3.76 million short tons are estimated to result from the CAAAs. By the year 2000, the CAAAs are estimated to account for an additional 7.01 million short tons, contributing to total production of 153.56 million short tons, a five percent increase.

The effects of the CAAAs on coal production are expected to moderate through the years 2001 to 2010. By 2010, coal production is east Kentucky is expected to total 186.13 million short tons. Of this, 3.59 million short tons, or an additional two percent, are the estimated effects of the CAAAs.

Coal Prices

The CAAAs are expected to have significant effects on the minemouth coal prices over the next twenty years. As the demand for high-sulfur coal declines, prices for this coal will also decline. Conversely, as the demand for low-sulfur coal increases, prices will increase. These price impacts are expected to be moderate in 1995 (Table 13). Kentucky coal prices are projected to average $34.13 per short ton (in constant 1990 dollars) in the year 2000. The CAAAs are expected to result in a price increase of $3.26 per short ton, or an eight percent increase. By 2010, coal prices are expected to average $40.24 per short ton, $4.57 (or 13 percent) higher because of the CAAAs. (Note: All prices have been adjusted for inflation over time periods, so they reflect real price changes.)

West Kentucky coal prices are projected to average $25.83 per short ton, in constant 1990 dollars, by 2000. This is estimated to be $2.65, or nine percent, less than prices would have been without the CAAAs. By 2010, west Kentucky coal prices are projected to average $29.63 per short ton. This reflects a projected decline of $2.15 per short ton, or seven percent, due to the CAAAs.

East Kentucky average coal prices are expected to be higher as a result of the CAAAs. By the year 2000, the minemouth prices of east Kentucky coal are expected to average $36.09 per short ton. The CAAAs are projected to result in an average price increase of $3.26 per short ton, or 10 percent. During the 2000 to 2010 year interval, it is assumed that a relative shortage of east Kentucky low-sulfur coal will develop. In order for this low-sulfur coal to be mined, buyers must be willing to pay prices which will cover production cost. Because of the high transportation costs incurred by purchasing low-sulfur coal from the western coal-producing states, utilities will find it cheaper to pay higher minemouth prices for east Kentucky low-sulfur coal. By the year 2010, east Kentucky coal prices are expected to reach $42.90. It is estimated that average coal prices will increase by $5.91, or 16 percent, due to the CAAAs.

Table 13
Projected Kentucky Coal Prices & Impacts of the Clean Air Act Amendments (CAAAs) of 1990: 1995, 2000, 2005, 2010
(1990 $ per short ton)

	1995			2000		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	30.51	31.56	1.05	32.83	36.09	3.26
West Kentucky	26.67	26.62	-0.05	28.48	25.83	-2.65
Kentucky Total	29.53	30.31	0.78	31.63	34.13	2.50

	2005			2010		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	36.00	40.99	4.99	36.99	42.90	5.91
West Kentucky	30.46	28.01	-2.45	31.78	29.63	-2.15
Kentucky Total	34.54	38.48	3.94	35.67	40.24	4.57

Source: Energy Information Administration, Coal Data Analysis and Forecasting Division

Total Value of Production

The combined price and quantity impacts are reflected in the total value of production. Despite the projected loss in state coal production due to the CAAAs, the increase in the average price of Kentucky coal results in an increase in the total value of coal produced in the state (Table 14). In the year 2000, the value of coal production is expected to total $6,479 million, approximately $77 million higher than the value would be without the CAAAs. By the year 2010, the total value of state coal production is estimated to be $9,365 million. The effects of the CAAAs are an estimated increase of approximately $640 million.

The total value of production from west Kentucky coal is expected to be $937 million by 2000. The CAAAs are estimated to result in a loss of $645 million. This is approximately a 40 percent loss, reflecting the combined effects of a 35 percent decline in production and a nine percent decline in average prices. By 2010, the total value of west Kentucky coal production is projected to be $1,380 million, approximately $593 million less than it would have been if the CAAAs were not implemented.

The average value of east Kentucky coal production is projected to total $5,542 million by the year 2000. Of this, approximately $731 million is estimated to be the result of the CAAAs, the combined effect of an estimated five percent increase in production and a 10 percent increase in prices. By 2010, the value of east Kentucky coal production is expected to increase by $1,232.82 million, due to the CAAAs, contributing to a total value of $7,984.98 million.

Table 14
Projected Value of Kentucky Coal Production & Impacts of the Clean Air Act Amendments (CAAAs) of 1990: 1995, 2000, 2005, 2010
(million 1990 $)

	1995			2000		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	4,339.44	4,607.44	268.01	4,811.24	5,541.98	730.74
West Kentucky	1,303.36	1,316.09	12.73	1,591.46	937.37	-654.09
Kentucky Total	5,642.80	5,923.54	280.74	6,402.70	6,479.35	76.65

	2005			2010		
Region	Without CAAAs	With CAAAs	Impact of CAAAs	Without CAAAs	With CAAAs	Impact of CAAAs
East Kentucky	5,896.44	6,997.40	1,100.96	6,752.15	7,984.98	1,232.82
West Kentucky	1,784.96	1,145.05	-639.91	1,973.54	1,380.46	-593.08
Kentucky Total	7,681.40	8,142.45	461.06	8,725.69	9,365.44	639.75

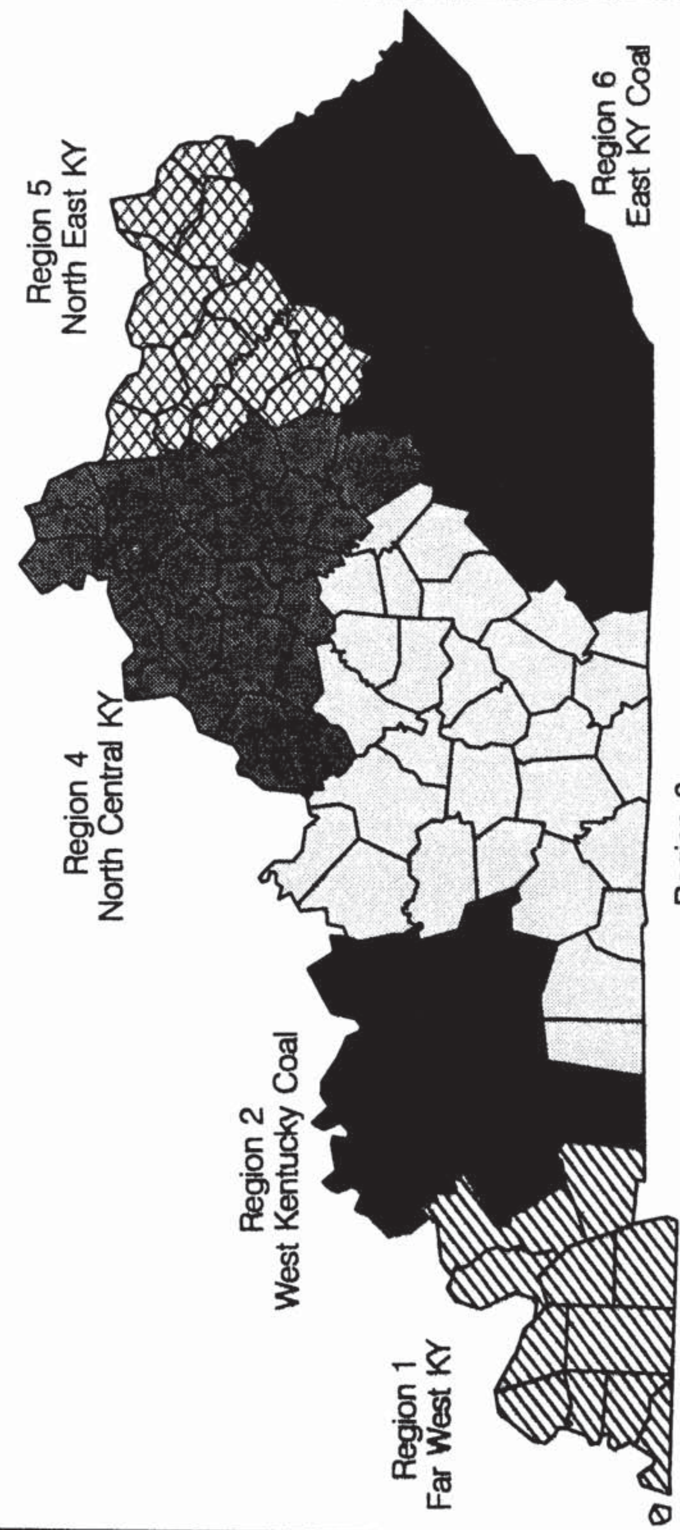
Calculated by Staff: (Projected Production) x (Projected Price), based on forecasts by the Energy Information Administration, Coal Data Analysis and Forecasting Division

The CAAAs Coal Market Effects and the Kentucky Economy

The indirect economic impacts of the acid rain provisions were estimated by using the Kentucky Regional Economic Model (REMI). This model was developed for the Legislative Research Commission by Regional Economic Models, Inc. The REMI model is disaggregated into six Kentucky regions and is a 53-sector econometric model conjoined with a 466-sector input/output model. Figure 15 illustrates the Kentucky regions. REMI is a simulation of the Kentucky economy and includes a complete data history of the Kentucky regional economies and the United States economy. The historical relationships and a forecast of the United States economy are used to develop a control forecast for the Kentucky regions. An economic impact simulation is then conducted by altering this forecast with information on the direct impacts and developing an alternate forecast. The difference between the control and simulation forecasts reflects the estimated total economic impacts of the change under review.

The economic impacts of the CAAAs were estimated by altering the control forecast with estimates of the direct impacts, the change in the total value of production, obtained from the Energy Information Administration. The impacts are estimated at four points in the future: the years 1995, 2000, 2005, and 2010. Therefore, the estimated effects of the CAAAs represent the change from the projected future levels without implementation of the CAAAs. However, since the most significant production adjustments occur in the year 2000, the following discussion focuses primarily on the economic adjustments which occur in that year.

Figure 15
REMI Regions



The West Kentucky Coal Region

In the west Kentucky coal region, the total value of output in the mining sector is estimated to increase by $12.78 million in 1995 and be reduced by $654.09 million in 2000, $639.91 in 2005, and $593.08 million in 2010 (Table 14). Table 15 summarizes the indirect and induced impacts of the CAAAs on the west Kentucky coal region.

The effects of the Clean Air Act Amendments are fully realized by the year 2000. In that year, total employment in the west Kentucky coal region is estimated to be 10,792 less than it would have been without the CAAAs (from the Control forecast). This represents a difference of approximately 5.2 percent. Wage and salary disbursements are expected to be $267.1 million lower, in constant 1990 dollars, or 7.2 percent. Regional personal income, the sum of wages and salaries, transfer payments, and income from property, is expected to be $265.8 million, or 4.3 percent, lower. While both wages and salaries and property income are expected to be lowered by 2000, transfer payments are expected to be slightly higher. By the year 2010, the decline in the coal sector resulting from the CAAAs is expected to result in a loss of 8,623 jobs and $221.1 million in wages and salaries. Regional personal income is expected to be $302.5 million lower.

Table 16 summarizes the distribution of employment effects by economic sector. Mine sector employment includes both miners and other employees of mining companies, such as engineers and office personnel. The difference in mining sector employment includes employment directly and indirectly attributable to the CAAAs. The majority of employment effects in manufacturing, transportation and utilities, finance, insurance and real estate, and wholesale trade are generated by declines in demand by the mining sector for good and services. The majority of changes in retail trade and services result from reduced purchasing by local residents.

Table 15

Economic Impacts of the CAAAs on the West Kentucky Coal Region

	1995	2000	2005	2010
Employment	350	-10,792	-9,018	-8,623
Percent Change from Control	0.1%	-5.2%	-4.6%	-4.3%
Wages & Salaries (million 1990 $)	7.8	-267.1	-240.3	-221.1
Percent Change from Control	0.2%	-7.2%	-6.0%	-5.1%
Personal Income (million 1990 $)	7.9	-265.8	-285.3	-302.5
Percent Change from Control	0.1%	-4.3%	-4.2%	-4.2%

Table 16

Distribution of Employment Impacts in 2000
for the West Kentucky Coal Region

Economic Sector	Percent of Total
Manufacturing	0.4 %
Mining	37.3
Construction	3.3
Transportation & Public Utilities	3.4
Finance, Insurance, & Real Estate	4.3
Retail Trade	18.4
Wholesale Trade	4.7
Services	26.3
Agriculture, Forestry, & Fisheries	0.6
Government	1.22

The East Kentucky Coal Region

In the east Kentucky coal region, the total value of output in the mining sector with CAAAs is estimated to be $268.01 million higher than without CAAAs. The difference will be $730.74 million in 2000, $1,100.96 million in 2005, and $1,232.82 million in 2010 (see Table 14). Table 17 summarizes the indirect and induced impacts of the CAAAs on the east Kentucky coal region.

The largest change in coal production occurs in the year 2000. However, the value-added in coal production through price increases stimulates economic growth throughout the study period. In 2000, total employment is projected to be higher by 14,091 jobs, or 6.1%, due to CAAAs (control forecast). The change in employment is projected to generate an additional $333.7 million (constant 1990$) in wages and salaries and represents a change of 9.1%. Regional personal income is projected to be $385.8 million, or 4.9% , higher.

By 2010, it is projected that 23,393 jobs will be generated due to CAAAs, representing a change of 10.1 percent. In the same year, wages and salaries are projected to be higher by $600.9 million, or 14.1 percent, and regional personal income is expected to be $828.4 million, or 8.7 percent, higher.

Table 18 summarizes the distribution of employment gains by economic sector. Again mine sector employment includes both miners and other employees of mining companies. The gains in the mining sector also include both direct and indirect employment attributable to the CAAAs. Increases in manufacturing, transportation and public utilities, and wholesale trade are generated primarily from increases in mine sector purchases. The majority of gains in the retail trade and service sectors result from increased purchases by individuals.

Table 17

Economic Impacts of the CAAAs on the East Kentucky Coal Region

	1995	2000	2005	2010
Employment	5,664	14,091	20,669	23,393
Percent Change from Control	2.5%	6.1%	9.0%	10.1%
Wages & Salaries (million 1990 $)	130.3	333.7	516.8	600.9
Percent Change from Control	3.6%	9.1%	13.0%	14.1%
Personal Income (million 1990 $)	145.6	385.8	650.9	828.4
Percent Change from Control	1.8%	4.9%	7.4%	8.7%

Table 18

Distribution of CAAAs Employment Impacts in 2000 For the East Kentucky Coal Region

Economic Sector	Percent of Total
Manufacturing	0.2%
Mining	34.5
Construction	2.9
Transportation & Public Utilities	4.1
Finance, Insurance, & Real Estate	3.0
Retail Trade	20.1
Wholesale Trade	5.1
Services	25.5
Agriculture, Forestry & Fisheries	0.3
Government	4.4

Kentucky

Because of the economic linkages between the six Kentucky regions, the economic adjustments that occur in the two coal regions will generate economic adjustments in the other four Kentucky regions. Therefore, the state-wide economic impacts of the CAAAs are the combined effects of the impacts in both coal regions and the remaining four Kentucky regions.

The economic impacts of the CAAAs are summarized in Table 19. There is an increase in state employment in 1995, due to the projected increases in coal production in both regions. By 2000, the negative impacts on the west Kentucky coal region are offset by positive impacts in the east Kentucky coal region. In the year 2000, the projected increase in value of Kentucky coal production of $76.65 million (Table 14) is estimated to generate 3,209 jobs in Kentucky. The increase in jobs contributes

Table 19

Total Economic Impacts of the CAAAs on Kentucky

	1995	2000	2005	2010
Employment	6,917	3,209	12,932	16,508
Percent Change from Control	0.4%	0.2%	0.7%	0.8%
Wages & Salaries (million 1990 $)	153.2	64.8	302.3	419.3
Percent Change from Control	0.5%	0.2%	0.8%	1.1%
Personal Income (million 1990 $)	170.2	103.6	375.8	552.8
Percent Change from Control	0.3%	0.2%	0.5%	0.7%

an additional $64.8 million in state wage and salary disbursements and $100.6 million in state personal income. By the year 2010, the CAAAs are expected to generate an additional 16,508 jobs, $419.3 million in wages and salaries, and $552.8 million in state personal income.

Summary

Based on coal production and price projections estimated by the Energy Information Administration, the total value of the coal production in Kentucky is expected to increase as a result of the CAAAs. This growth is projected to result in a net increase in both employment and income for the state as a whole. However, there will be significant differences in how the CAAAs affect individual regions within Kentucky.

In the year 2000, the west Kentucky coal region is projected to experience substantial economic losses due to the CAAAs. Employment is expected to be 10,792 jobs lower than it would have been without the CAAAs, representing a 5.2 percent change in the region. Wages and salaries are expected to be $267.1 million, or 7.2 percent, lower. These changes will significantly stress communities and local governments in the west Kentucky coal region.

The east Kentucky coal region is expected to benefit from the CAAAss. The combination of higher levels of coal production and higher average prices for coal contribute to substantial economic gains for this region. In the year 2000, employment is estimated to be higher by 14,091 jobs, or 6.1%, while wages and salaries are expected to be $333.7 million, or 9.1 percent, higher. The increased value of coal production is expected to generate economic benefits through the next decade. However, increases in the value of coal production are due to price increases resulting from diminishing supplies of low-sulfur coal. Therefore, the economic gains from the CAAAs may be mitigated as these reserves are exhausted.

The Electric Utility Market Effects

Title IV of the Clean Air Act Amendments will significantly affect electric utility markets by increasing the cost of producing electricity for many utilities. Electric utility managers must decide how best to comply with the new regulations. Assuming utilities are currently minimizing the cost of generating electricity, any method of compliance will increase the costs of electricity generation. Upon approval of rate governing institutions, these cost increases will be passed on to electricity consumers through higher electric rates.

Unfortunately, estimates of the effects of the CAAAs as enacted on Kentucky ratepayers are not available. However, it is important to recognize that electricity consumers will face higher electric utility rates. The magnitude of the rate increases will depend on how utilities comply with the CAAAs amendments and on the size of the service area.

Since electric utilities provide service to a particular service area or region, the effects of increases in electric utility rates are also likely to be a regional phenomenon. For example, utilities which currently meet both Phase I and Phase II regulations for emissions will not be forced to increase rates. Utilities which currently meet Phase I requirements, but not Phase II, will be able to delay rate increases until after 1995. However, utilities which do not currently meet Phase I emission requirements must begin planning compliance strategies within the year. If a utility chooses to make investments in scrubbers, rate increases may be incurred prior to 1995.

The size of the rate increases will be dependent on the size of the service area. Economies of scale would indicate that the larger the customer base, the smaller the per customer price increases necessary to recoup the investment costs. For example, an investment of $100 million for a scrubber by a utility with a small service area (in number of customers) will require that the costs be spread over a small number of customers, thereby generating greater increases in electric utility rates than the same investment for a utility having a large service area with many customers.

The incidence of the rate increases will depend on who uses electricity and how much electricity is utilized. There are four basic categories of electricity consumers: residential, industrial, commercial, and "other." The distribution of electricity sales to consuming groups is illustrated in Figure 16. In 1989, residential customers, or private households, accounted for 34.0% of electricity sales in the United States and 29% in Kentucky.

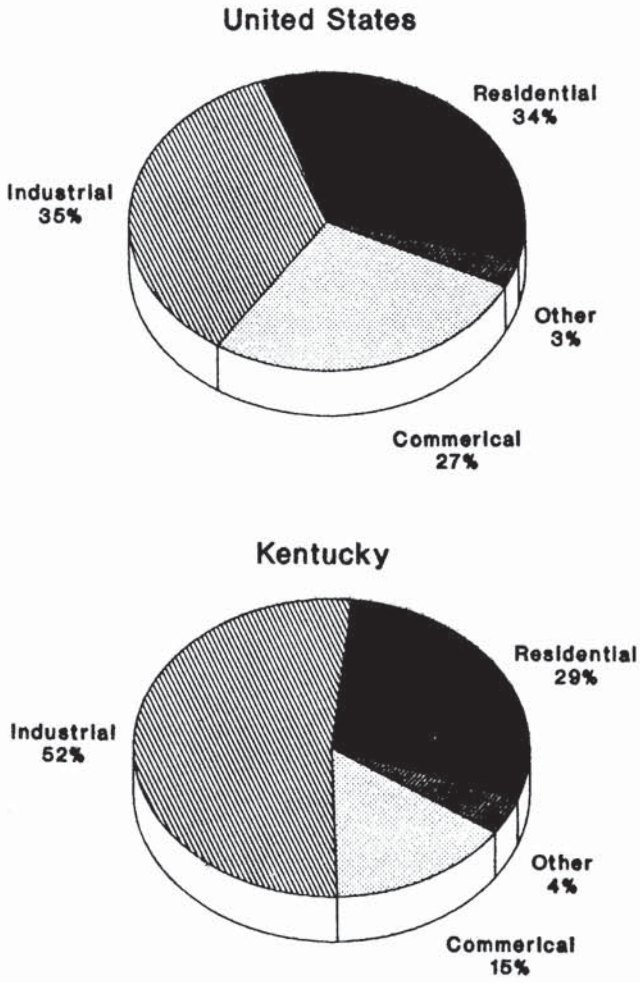
Industrial facilities account for the bulk of electricity sales at both the state and national level. Industrial facilities include the manufacturing, construction, and mining sectors. In 1989, 35% of electricity sales in the United States were to industrial facilities. However, this sector accounted for 52% of sales in Kentucky, a much higher share than the national average. This is not surprising, given that Kentucky has a larger share of employment and earnings in these sectors than the United States as a whole.

The commercial sector includes the service and retail sectors. This sector accounted for 27% of electricity sales in the United States and 15% in Kentucky. As the service sector increases its share of both the national and state economies, this sector will account for a larger share of electricity sales.

The "other" category primarily includes state and local governments, and public streets and highways. The sector accounted for 3.0% of electricity consumption in the United States and 4.4% in Kentucky.

These groups of electricity consumers will all be faced with higher electric utility rates. In the short-run, the demand for electricity is relatively inelastic. That is, as electric rates increase, consumers will not significantly change their electricity use. Therefore, the share of income devoted to paying electricity bills will increase. Residential customers will adjust household budgets and forego other expenditures. Industrial customers will face higher production costs. Commercial facilities will face higher operating costs. However, in the long-run, it is anticipated that electricity consumers will become more energy efficient, thereby reducing the share of income spent on electricity.

Figure 16
Share of Electricity Sales to Consuming Sector, 1989



Source: Electric Power Annual, 1989
Energy Information Administration
U.S. Department of Energy

CHAPTER V

LEGISLATIVE ACTIVITY

Legislative meetings on Title IV of the Clean Air Act Amendments of 1990 began soon after the CAAAs were signed into law. Some initial work was done by the Task Force on Energy before it was merged into the Tourism Development and Energy Task Force. However, most of the work was done by the new task force's Subcommittee on Energy. Testimony was received from coal producers, coal miners, utility representatives, university researchers, and from representatives of a number of state agencies. This chapter identifies and discusses the issues that emerged from these meetings. Audio tapes and the minutes from the meetings are available in the Legislative Research Commission's library, located on the fourth floor of the Capitol Building in Frankfort.

Other States' Reactions

One of the first steps taken in this study effort was to determine other states' initial responses to the CAAAs. Throughout the process the Subcommittee on Energy followed very closely efforts in other states to preserve their own high-sulfur coal markets. The monitored states included Indiana, Ohio, Illinois, West Virginia, and Pennsylvania. Some states, like Indiana and Ohio, are net coal importers, and are logically focusing all efforts on their in-state markets. But even a state like Illinois, which has a large out-of-state coal market, is finding it much harder to affect compliance decisions of out-of-state utility coal buyers through the legislative process. Consequently, legislation enacted in these states in response to the CAAAs, thus far, addresses in-state markets almost exclusively.

All five states considered proposals to make changes in the way costs for pollution control equipment are treated by state utility regulatory agencies. In the legislation eventually adopted by four of the five states, the state public utility regulatory commission is a major focus.

Regulated utilities considering installation of scrubbers or clean coal technology face the risk that after installation their investment in the equipment will be found "imprudent" by the state utility regulatory commission. This can happen even after the utility regulatory body gives "initial" approval to begin installation. Utilities typically make their decision to install equipment without assurance that they will eventually recover their investment costs in the rate base. Because fuel switching requires much less capital investment, it is considered less risky. The states which were studied identified the uncertainty on return of investment as an important disincentive to continued use of in-state coal. These states sought to make the scrubber option less risky by putting in place assurances that investments will be protected.

A summary of the state legislative packages is provided below. The subcommittee tracked legislative efforts in these states primarily to identify actions which Kentucky might also want to consider taking. Incidentally, it should be noted that actions taken in some of these states, particularly in Ohio, Indiana, and Illinois, could reduce the use of east Kentucky coal in those states.

West Virginia. West Virginia took action even before the CAAAs were passed. In anticipation of federal legislation, West Virginia passed a bill in August of 1990 (West Virginia Code 24-2-1g and 24-2-11b) to permit the state public service commission to authorize utility rate-making incentives for investments in clean coal and clean air technology facilities.

Indiana. The second state prompted to adopt legislation in response to the new federal acid rain control mandate was Indiana. Senate Bill 514, enacted in April 1991, sets out a voluntary procedure for utilities seeking up-front approval on their clean air compliance plans. Any compliance plan submitted to the state's public service commission that includes displacement of Indiana coal must also include an analysis of the economic and unemployment effects of any fuel switch. Under the provisions of the new law, the public service commission must consider the economic effects of any compliance plan on both the state's mining industry and the utility's customers. A compliance plan approved by the commission prior to implementation guarantees the utility full recovery of costs and return on investments associated with the plan, barring fraud or gross mismanagement.

Ohio. With passage of Senate Bill 143, in June of 1991, the Ohio legislature opted for a more comprehensive and expensive package than West Virginia or Indiana. Senate Bill 143 establishes a tax credit against the state's public utility gross receipts tax. The tax credit is $1.00 for each ton of coal burned in a scrubbed unit, up to 20% of costs associated with scrubber installation. Utilities that already have installed scrubbers are eligible for the credit. The tax credit is estimated to cost the state approximately $20 million annually.[18]

Like the Indiana bill, SB 143 permits utilities to submit their clean air compliance plans to the public utility commission. Any compliance plan submitted should represent a utility's least-cost strategy for compliance through Phase II of the new clean air program and, to the maximum extent possible, provide for the use of Ohio Coal. Approved compliance plans are to be guaranteed full recovery of costs and return on investments associated with the plan. In addition, the state's public utility regulatory commission is authorized to permit a company with an approved plan to include costs associated with scrubber installation on a utility surcharge.

The Ohio law also establishes an expedited permit process for scrubber installation and disposal of scrubber waste, provides for accelerated depreciation of scrubbers, and makes utilities eligible for low-interest loans for scrubber installations.

Illinois. The General Assembly of Illinois chose to mandate that scrubbers be installed at its largest coal-fired plants. Senate Bill 629, adopted in July of 1991, requires Commonwealth Edison and Illinois Power and Light to install scrubbers on a total of four units. The legislation requires all electric utilities to file a Clean Air Act compliance plan with the state's utility regulatory agency. Compliance plans are required to take into account the need for a minimal rate impact and for continued use of Illinois coal. An up-front guarantee for recovery of costs and return on investments is given to scrubber installation, as long as costs are consistent with those specified in the approved compliance plan. At the same time, recovery of increased coal transportation costs, through a fuel adjustment clause, is specifically prohibited, if the costs incurred involve a switch in fuel sources.

Senate Bill 629 increased state bonding authorization, to provide a $35 million grant to Illinois Power and Light, which was to be used in conjunction with its application for funding from the U.S. Department of Energy's Clean Coal Technology Program. While Illinois Power and Light did not receive federal clean coal funding, it appears that the utility will still receive the grant to help finance a conventional scrubber.

Finally, Senate Bill 629 expands the powers and duties of the state's Coal Development Board.

Illinois continues to strategize on how to protect its out-of-state utility coal market, which accounts for almost two-thirds of the coal it sells. The governor appointed a delegation of state officials and coal industry representatives to wage an aggressive campaign to promote Illinois coal. This delegation is meeting with out-of-state utility executives, armed with economic and scientific information developed by state universities and agencies, to convince utilities that making technological changes to burn Illinois coal can be the most economical and environmentally-sound decision for their clean coal compliance. This delegation is also considering possible formation of a coalition of midwestern states, including Kentucky, to pool their resources to promote high-sulfur midwest coal.

Other strategies being considered include: (1) marketing Illinois coal and scrubbers as a package; (2) expanding use of state coal development bonds for out-of-state coal projects; and (3) encouraging trading of SO_2 allowances between Illinois utilities and out-of-state utilities that continue to burn Illinois coal. Efforts are also underway in Illinois to increase its coal exports.

Pennsylvania. The main action thus far taken by Pennsylvania is adoption of House Resolution 106, which petitions the governor to protect Pennsylvania coal by invoking Section 125 of the Clean Air Act. This section allows the governor of a state, with the written consent of the President of the United States, to prohibit a utility from using non-local coal to comply with the law, if it would result in significant local or regional economic disruption or unemployment. Section 125 was adopted by Congress in 1977, but has been used infrequently.

Economic Analyses

Two different economic analyses were presented to the Subcommittee on Energy. The first analysis was done by Dr. Charles Haywood, Director and Chief Economist of the University of Kentucky's Center for Business and Economic Research. This analysis can be found in Appendix C. The second analysis was presented by LRC's staff economists and is contained in full in Chapter IV of this report.

West Kentucky Coal's Contribution to the Economy

Dr. Haywood's analysis was prompted by concerns that TVA might reduce by half its west Kentucky coal purchases in favor of Wyoming coal. This analysis calculated west Kentucky coal's contribution to the Kentucky economy. It did not predict how coal markets would be affected by the CAAAs. Based on a value of coal at $24 per ton, Dr. Haywood estimated that for each million tons of west Kentucky coal production lost, there would be corresponding losses of: (1) $49.65 million in annual total output of goods and services; (2) $14.51 million in annual household and individual earnings; (3) 631 jobs; and (4) $3.5 million in state tax collections.

Impacts which the analysis noted but did not attempt to measure included increases in state expenditures for certain social programs and adverse impacts on local governments in coal-producing counties. A further effect identified in the analysis is the "feedback" effect on TVA itself. Reduced coal production will indirectly reduce electric power sales.

LRC Economic Analysis

The LRC economic analysis, as contained in Chapter IV and presented to the Subcommittee on Energy, did estimate the effects of the CAAAs on Kentucky's economy, based on projections made by the Energy Information Administration (EIA). Numerous questions were raised by subcommittee members and others concerning the EIA economic projections, and the EIA was asked to clarify some of its methods.

Included in comments received by the subcommittee was the observation that the EIA projections may overestimate the increase in the price of east Kentucky coal and in coal production in both Kentucky coalfields. It was suggested that the EIA model failed to consider eastern U.S. utilities as a viable market for Wyoming and other western U.S. coal. However, when contacted by LRC staff, EIA indicated that the competitiveness of Wyoming coal, as well as that of all coal supply regions, was taken into account in its estimation of the impacts of the CAAAs on Kentucky coal production.

Also called into question was whether east Kentucky had the low-sulfur coal reserves assumed in the EIA model. As one utility coal buyer told the subcommittee, his utility would not be considering a scrubber if it could be assured of an adequate, long-term supply of Kentucky low-sulfur coal.

Technology Bonus Allowances in Phase I

The subcommittee quickly recognized the importance of the Phase I bonus allowances which are to be made available for installation of scrubbers or other technology to reduce sulfur emissions by 90%. The degree of certainty of obtaining a portion of the 3.5 million bonus allowances appears to be a key factor in utility decisions to scrub or not. Bonus allowances will mean they can minimize future rate increases for their customers.

From the day the CAAAs were signed into law, it was anticipated that there would be an oversubscription of these allowances, by as much as two to one. As EPA began plans to distribute these bonus allowances, western states with low-sulfur coal pushed for a distribution system of first-come, first-served. This type of distribution system will discourage utilities from attempting to scrub and qualify for the bonus allowances - since they could well end up with no bonus allowances. Phase I-affected utilities and states with high-sulfur coal pushed for a system whereby each utility applying for the allowances on a given date would be assured a portion of the allowances. It appears that western states have won on this issue. The EPA now plans to award the bonus allowances through an elaborate telephone queuing system that amounts to a lottery.

There is an effort underway to get most of the utilities who plan to try for the bonus allowances to pool their interests. Each member of the pool would agree to share any bonus allowances won in EPA's telephone lottery system. Such a pooling arrangement would lessen the risk of losing out entirely and, if most utilities participate, would accomplish the pro rata distribution method originally sought. EPA has indicated that it has no problems with a redistribution of the bonus allowances, as long as those utilities who actually "win" by queuing in first install the technology controls.

Utilities in the State

In an effort to determine how utilities in the state will react and how ratepayers will be affected by the CAAAs, the Subcommittee on Energy surveyed electric-generating utilities in the state. State utilities were asked to explain in writing their plans for compliance and any related projected rate increases. In addition, they were asked to make recommendations on how the state could mitigate the negative impacts of the acid rain legislation.

Utility Compliance Plans

Most of the utilities surveyed offered testimony at the subcommittee's June 10, 1991 meeting. Information presented by the utilities at that time was sketchy. Few of them had finalized their compliance plans. Most utilities were unsure about how significant a reduction of NO_x they would have to make, but they did indicate that they plan to install special equipment to control those emissions. A summary of each utility's compliance plan, as relayed to the subcommittee, follows. All utilities which testified are regulated by the state's Public Service Commission except Owensboro Municipal Utilities. The Tennessee Valley Authority (TVA), which has generating units as well as utility customers in the state, also offered testimony and is discussed in a separate section of this report.

Louisville Gas and Electric Company. One of only two utilities in the state not affected in Phase I, Louisville Gas and Electric anticipates it will be able to run its system as is with its alloted SO_2 allowances. Louisville Gas and Electric Company is well positioned for clean air compliance, because all of their coal-fired boilers are equipped with scrubbers. They are currently evaluating selling excess allowances.

Kentucky Power Company. The only other utility not affected by Phase I is Kentucky Power Company. Because Kentucky Power is part of a large holding company, American Electric Power Company, its strategy will be somewhat dependent on the parent company strategy. Kentucky Power has only one power plant located in the state, Big Sandy, located in Louisa. In Phase II, the Big Sandy units will have alloted allowances of approximately 28,000 tons of SO_2 per year, compared to 62,600 tons actually emitted in 1990. Kentucky Power reported that it would likely increase its use of Kentucky low-sulfur coal to make its Phase II reductions. It is also considering purchase of allowances.

Big Rivers Electric Corporation. The Big Rivers utility system, which sells electricity to four rural electric cooperatives, also includes the Henderson Municipal Power and Light Plant, operated for the city of Henderson. Fifty-one percent of Big Rivers' generating capacity is scrubbed. Five unscrubbed units are affected in Phase I, and Big Rivers plans a 47% reduction in SO_2. Additional adjustment, although not as large, will be required in Phase II. Big Rivers reported to the subcommittee that a consultant was studying how to make the necessary reductions.

Like most of the other companies, Big Rivers indicated that a rate increase will be necessary but declined to speculate on the size of the increase until a compliance plan was finalized. Since 65-70% of the power generated by Big Rivers goes to two aluminum smelters, any rate increase will impact those facilities and possibly the 1500 to 2000 employees of the two aluminum smelters.

Based on the consultant's report, Big Rivers later decided to switch its Coleman plant to a lower-sulfur coal and to scrub the two units at the plant it operates for Henderson.

East Kentucky Power Cooperative, Inc. East Kentucky Power Cooperative serves 18 rural electric cooperative transmission facilities. This utility has two Phase I units and three additional units which will come under Phase II. Two other units are exempted entirely because they are below 25 megawatts. East Kentucky Power is considering either installing a scrubber or switching to low-sulfur coal at one or two units. Also being considered, but not as likely, is the repowering of two units with a clean coal technology, such as fluidized bed combustion.

The utility expects minimal financial impact for Phase I and a wholesale rate increase not to exceed 10% for Phase II.

Kentucky Utilities. Both high and low-sulfur coal is burned by Kentucky Utilities (KU) to generate electricity for its own customers and 11 municipal utility systems. The company has five Phase I-affected units and must make an estimated 44% reduction in SO_2 emissions for these units by 1995. Clean air compliance for Phase I at KU will primarily focus on the utility's largest SO_2 emitter, the Ghent I unit. KU plans to install a scrubber there, at an estimated capital cost of $150 million. To complete its Phase I compliance strategy, KU plans to switch fuel at its E.W. Brown plant, from an average 2% sulfur content coal to less than 1.5% sulfur.

Phase II compliance strategy for KU, as described to the subcommittee, includes installation of two or three more scrubbers and switching to a lower-sulfur fuel at its Green River plant. The company plans for a 75% reduction in current SO_2 emission levels by 2010.

Owensboro Municipal Utilities (OMU). The city of Owensboro owns and operates the Elmer Smith plant, a coal-fired, 416-megawatt, two-unit facility. The units currently burn approximately 1,000,000 tons of coal per year - all from western Kentucky. Under contract provisions, Kentucky Utilities purchases power not needed by OMU. Both units at Elmer Smith will come under the new acid rain controls in Phase I. Because the formula to allot SO_2 allowances is based on a period in 1985-1987 when OMU's emissions were artificially low, due to outages and reduced demand by Kentucky Utilities, OMU is saddled with very large SO_2 emission reductions. OMU plans, as related to the subcommittee, are to install a scrubber to serve both units, at an estimated cost of $147 million. Owensboro electric utility customers will probably face the steepest rate increases of any utility rate customers in the state for clean air compliance. OMU anticipates the need to increase its revenues by 60% by January 1, 1995.

Certain actions the state might take to help lessen the severity of the CAAAs on Kentucky electric utilities would not benefit OMU. Since OMU is not regulated by the Public Service Commission and is a municipal-owned utility, certain regulatory reforms and tax incentives would not apply. In testimony before the subcommittee, a representative of OMU stressed the need for incentives to be made available to all state utilities.

Utility Recommendations

Kentucky's utility companies have offered the following recommendations regarding how the state could assist in clean air compliance. Since this list is a compilation of recommendations made by individual utilities, individual recommendations are not necessarily consistent with all other recommendations. Additional recommendations made by TVA are discussed in a later section of this report.

- Increase funding and staffing for the Governor's Office for Coal and Energy Policy, to plan and implement research programs designed to develop new and more effective and environmentally acceptable uses for coal.

- Work with other states for the amendment of the Federal Tax Reform Act of 1986, to restore tax-free treatment of pollution control bonds.

- Ensure that any necessary state requirements relating to CAAAs implementation are no more restrictive than federal mandates and that EPA and state permitting programs are consistent.

- Assist utilities in disposal of coal combustion byproducts, especially scrubber sludge.

- Shorten the time required for utilities to obtain waste disposal permits.

- Encourage and enable free and open trading of SO_2 allowances, both within and outside of the state.

- Require that surplus SO_2 allowances first be offered for sale or exchange to utility sources within Kentucky before such allowances are sold or traded to others outside of Kentucky. (This recommendation is in contrast to the preceding one.)

- Enable utility companies to fully recover in a timely fashion all expenses associated with compliance with all environmental laws and regulations.

- Provide tax breaks to utilities installing scrubbers.

- Reduce or eliminate the coal severance tax entirely, or for coal going to scrubbed facilities.

- Make capital available at preferential rates to utilities faced with high capital costs associated with CAAAs compliance.

Tennessee Valley Authority

The Tennessee Valley Authority (TVA) was also asked to appear before the Subcommittee on Energy, not only to discuss the CAAAs' effect on Kentucky operations and customers, but to discuss compliance within its entire system. TVA is the largest utility in the United States, providing services in parts of seven states, including southwest Kentucky. Two of TVA's eleven coal-fired plants are in Kentucky, the Paradise and Shawnee steam plants. TVA's compliance plans are especially important to the state, since it is the largest buyer of western Kentucky coal (approximately 18 million tons annually). In 1990, TVA purchased almost 38% of the region's total coal production.[19] TVA is not regulated by the Kentucky Public Service Commission or any other utility regulatory body.

TVA's testimony

Twenty-six units at TVA are affected in Phase I. By the beginning of Phase II, January 1, 2000, TVA plans to reduce its SO_2 emissions by two-thirds, or 750,000 tons annually, the largest single utility SO_2 reduction in the United States.

Initially, TVA considered three compliance options for its system. The first two options involved fuel switching at certain units to either Wyoming coal or central Appalachian coal, thus displacing approximately nine million tons of west Kentucky coal annually. The third option was to scrub a unit at its Paradise plant and two units at the Cumberland plant and continue to burn west Kentucky coal.

In testimony before the subcommittee, the president of the Tennessee Valley Authority Power Generating Group indicated that for Phase I compliance alone, the estimated annual operation and maintenance costs favor a switch to Wyoming coal over scrubbing, by a range of \$20-\$40 million. The difference in capital investment for the years 1991-2005, in 1991 dollars, favors both switch options (Wyoming or Appalachian) over scrubbing, by a range of \$110-\$500 million.

TVA Recommendations to State

TVA made it clear that it was looking to west Kentucky coal producers and miners - and even the state - to make the scrubbing option cheaper. Among the recommendations TVA made to the state to help effect its final compliance plans, as well as those of other utilities were:

- A rebate or reduction on the coal severance tax for high-sulfur coal.

- Grants for scrubbers or state ownership of scrubbers or joint ownership with TVA.

- Rebate or exemption from certain taxes or tax equivalent payments.

- State ownership of rail cars currently owned by TVA and other utilities for use in shipping high-sulfur coal.

- Sharing the risks utility buyers of high-sulfur Kentucky coal face in developing a compliance strategy, by underwriting the price of any surplus allowances offered for sale by TVA or other utilities or offering to buy allowances in the open market for those utilities not successful in receiving the limited bonus allowances set aside in Phase I for scrubber or clean coal technology installations.

Southern Legislative Action

Based on information gathered by the Subcommittee on Energy on TVA and other utility users of west Kentucky coal, the Kentucky state legislative delegation took the clean air compliance issue to the Southern Legislative Conference. At Kentucky's initiative, the Southern Legislative Conference, on July 23, 1991, adopted a resolution urging Congress to: (1) appropriate money to cut the cost of building scrubbers at TVA; (2) adopt tax incentives and favorable bond financing for pollution control devices; and (3) clarify by legislative action that the special bonus allowances available for scrubber or clean coal technology installation in Phase I should be shared by all eligible applicants.

Task Force Action

TVA's announcement that it was considering an annual purchase of nine million tons of coal from Wyoming to replace Kentucky high-sulfur coal prompted the Governor to consider calling a special session to adopt an incentive package. In September of 1991, the Tourism Development and Energy Task Force sent the Governor a letter requesting a briefing on his negotiations with TVA. The task force also petitioned the Kentucky congressional delegation to remind their colleagues that TVA's primary commitment should be to help the region it serves, not to demand subsidies of the region to keep its business.

TVA's Latest Compliance Plan

On October 10, 1991, the president of the TVA Utility Generating Group held a press conference to announce that the staff was recommending a compliance strategy to the TVA board which would avoid significant impacts on the Kentucky coal market and would not require state incentives. The TVA board later adopted the staff recommendation.

The plan calls for scrubbing two units at the Cumberland plant and making no changes at the Paradise plant. Paradise will continue to burn west Kentucky coal. TVA will switch to Wyoming coal at the Gallatin plant in Tennessee, if tests prove that is feasible. While the fuel switch at Gallatin will mean displacement of up to two million tons of Kentucky coal there a year, the utility will actually increase the total amount of Kentucky coal it purchases because of new efficiencies planned throughout the system and additional coal required for the scrubbed units.

The compliance plan announced by TVA is contingent upon receipt of 700,000 of the 3.5 million special scrubber bonus allowances EPA will distribute via the telephone lottery discussed earlier. TVA values the 700,000 allowances at $120 million in 1992 dollars.[20] If TVA does not receive at least a portion of the bonus allowances being sought, it may reconsider its compliance plan.

With receipt of this announcement, the Subcommittee on Energy concluded that an important segment of the west Kentucky coal market is, for the moment, protected. In response to the condition attached to the TVA announcement, the Subcommittee sent a letter to the President of the United States and to certain members of Congress, urging them to convince EPA to allocate the Phase I technology bonus allowances on a pro rata basis.

Public Service Commission

Public utility regulatory agencies will play a pivotal role in utility plans to comply with the CAAAs. They can encourage the use of technology to ensure clean air compliance by their set regulatory policies and through informal communications. Their review of alloted SO_2 allowances bought or sold by utilities they regulate will influence the success of the allowance trading program. The effort to organize a utility sharing arrangement of bonus allowances for early Phase I compliance discussed earlier will not succeed unless the regulatory agencies send a clear signal that there will be no penalties for participating in such a pool. Finally, regulatory oversight will serve as a check to ensure compliance plans chosen are in the best interests of ratepayers.

The chairman of the Kentucky Public Service Commission (PSC), in testimony before the Subcommittee on Energy on July 15, 1991, indicated that current law restricts the PSC's ability to react to certain clean air quality issues. He indicated that the commission would need new statutory authority to consider a utility's clean air compliance plan's social costs or its effects on the state's overall economy. He also stated that statutory changes would be necessary to follow Ohio's lead of assuring prompt and full recovery of clean-air related costs through a fuel adjustment clause.

Shortly after the chairman's testimony, the Public Service Commission issued an administrative order directing all regulated electric generating utilities to submit their compliance plans for both Phase I and II. Policy set by the PSC, however, will have minimal impact initially on west Kentucky coal markets, since only 6% of west Kentucky's coal now goes to targeted Phase I utilities regulated by the PSC.[21]

Waste Problems

A problem already experienced by some utilities in the state emerged from testimony presented: lack of a low-cost disposal option for coal combustion waste, especially scrubber sludge. One utility representative described accumulated sludge beside one scrubbed facility in the state as covering 40-acres and being 60-feet high.

Research is being done on ways to use scrubber sludge. It can be used as a concrete substitute. The Transportation Cabinet successfully used scrubber sludge on a highway exit in west Kentucky. However, the project failed to generate any market for the scrubber byproduct. One utility official testified that it was using some scrubber sludge as a landfill cover; another indicated that his utility was placing a portion of its sludge in strip mine pits, with the approval and assistance of the Natural Resources and Environmental Protection Cabinet. Some scrubbers now on the market produce gypsum as a byproduct. However, because gypsum is so abundant, market outlets for this byproduct are uncertain.

According to KRS 224.868, scrubber sludge is classified as neither solid waste nor hazardous waste. It is placed in a category called special waste, which includes oil production brines and cement kiln dust. These wastes are recognized as high-volume wastes with low hazard. Prompted by action in the 1990 General Assembly, the Natural Resources and Environmental Protection Cabinet is drafting special waste regulations. Regulatory treatment of coal combustion byproducts is also being reviewed at the federal level. Requirements set out in these regulations will affect future methods and costs of utility combustion byproducts and could affect future utility plans to install scrubbers.

Wyoming Coal

Because Wyoming coal is believed by many to be the most serious threat to both east and west Kentucky coal fields, as utilities seek to comply with the amendments, the Subcommittee on Energy closely examined the Wyoming and Kentucky coal-mining activities. A number of utilities now using Kentucky coal have test-burned Wyoming coal. Wyoming's coal has successfully penetrated eastern U.S. markets. For example, 23% of coal burned by Indiana utilities is from Wyoming.[22] Although much lower in Btu value, Wyoming coal is also very low in sulfur and cheaper to mine than Kentucky coal. (See discussion in Chapter III on factors affecting coal markets.)

Because Wyoming minemouth coal prices are approximately one-third of those in Kentucky, the Subcommittee on Energy requested the Natural Resources and Environmental Protection Cabinet to study the mining regulations of each state, to determine whether the differences in regulations account in any way for the difference in prices. The Deputy Commissioner with the Department for Surface Mining Reclamation and Enforcement briefed the subcommittee on his agency's review of the regulations of the two states. He said both states have been delegated regulatory primacy under the federal Surface Mining Act and have been found to be consistent with the federal law. The deputy commissioner found no glaring disparities between the two states' regulations. He indicated that similar price differences existed prior to the enactment of the 1977 Surface Mining Act. More than anything else, Wyoming's larger, thicker coal seams make that state's coal cheaper to produce. In Wyoming, 35 to 60 feet of overburden (the material overlying a coal deposit) is removed to mine 70 to 120 feet of coal. Similar amounts of overburden removed in Kentucky produce only three to five feet of coal.[23] Also, almost all of Wyoming's coal is mined by surface mining, but over 60% of Kentucky's coal is mined underground.[24]

Future Challenges for Coal

The Subcommittee on Energy has identified two looming issues as potentially greater threats to the Kentucky coal industry than the acid rain control legislation: the global climate change debate and coal's growing reputation as an undesirable fuel. These issues present new challenges to the industry to find ways to burn coal more efficiently and cleanly.

Global Climate Change

There is growing concern that emissions from man-made gases are causing a gradual warming of the earth. The debate on global climate change has elements similar to those which surrounded the acid rain issue. Major uncertainties remain on how serious a threat global climate change presents. Some are pushing for more research, while others are pushing for immediate action. Like acid rain, coal-fired utilities are a primary target for mandated reductions. But it is primarily the carbon dioxide produced from the burning of coal and other fossil fuels, rather than sulfur or nitrogen oxides, that contributes to the so-called global warming effect. Unfortunately, carbon dioxide emissions are harder to control than sulfur and nitrogen oxide emissions. The primary method for carbon dioxide disposal is deep ocean and underground injection, but this process is considered cost-prohibitive. A study by the Electric Power Research Institute indicated that scrubbing 90% of the carbon dioxide from one plant's emissions and injecting the collected carbon dioxide into the ocean would increase the cost of electricity at that plant by 180%.[25] Short of banning coal combustion, the most cost-effective way to control carbon dioxide electric-generating units appears to be increasing energy efficiency. For every 5% improvement in plant efficiency, a 15% cut in carbon dioxide generation results.[26]

Debate on global warming is proceeding on two fronts: the U.S. Congress and the international community. At least 26 bills have been introduced in the 102nd Congress dealing with some aspect of global warming.[27] One proposal, HR 1086, would impose a carbon tax on fossil fuels, including an $18 per ton tax on coal. Another proposal, HR 2663, would make major new sources of carbon dioxide offset their emissions through a mechanism similar to the sulfur dioxide allowance trading system contained in the CAAAs.

It is, however, on the international front that the global debate is accelerating. Intense negotiations to reduce carbon dioxide have already begun by the United-Nations-sponsored International Panel on Climate Change. With over 100 countries participating, this panel is attempting to develop a draft treaty on climate change for consideration by the so-called Earth Summit, to be held in Brazil in June of 1992. Such a treaty could call for world-wide limits on carbon dioxide emissions.

Coal's "Dirty" Image

Ironically, just as great strides are being made to develop technology to make coal a clean-burning fuel, public surveys are showing growing opposition to increased use of coal to supply the nation's energy needs. As the assistant secretary for fossil energy in the U.S. Department of Energy puts it: "The most serious threat to coal is no longer in Congress. Instead, it is in a growing number of town halls and community meeting rooms."[28]

In New England, there are numerous examples of anti-coal policies by state and local governments. Massachusetts and Rhode Island have recently debated adoption of energy policies that preclude the use of coal. Local opposition to coal-fired facilities in Maine and New York have stalled coal projects. Some California communities have also demonstrated the NIMBY (not in my backyard) syndrome in opposition to coal-fired plants. More disturbing are indications that this trend appears to be moving to Kentucky coal markets to the south. For example, Florida Power and Light's efforts to expand a coal-fired plant and install clean coal technology were blocked by residents who oppose any form of coal use. Controversy in Tallahasee quickly heated up when the city received financial assistance from the U.S. Department of Energy's clean coal technology program to install the nation's largest circulating fluidized-bed combuster. Tallahasee recently withdrew from the project.

Unlike acid rain, this issue does not pit one coal-producing region against another. All coal is potentially threatened. Hence, there are opportunities for coal-producing states to pull together to combat coal's reputation as a dirty fuel.

Coal Research

Many believe that the future of coal is very closely linked to timely developments in clean coal technology. In the review of legislative action in high-sulfur coal producing states, it became obvious that some states are devoting more money and effort to clean coal technology than Kentucky. Ohio and Illinois lead the nation in state funding of clean coal technology. Research programs in these states are designed to attract both federal and private research dollars to solve coal-related problems specific to these states.

Illinois now has bond authorization of $120 million for research projects at utility generating plants and industrial facilities which use Illinois coal. The state has been the site of 17 clean coal technology demonstrations since 1978.[29] In addition, corporations receive an income tax credit equal to 20% of any donation they make to the Illinois Center for Research on Sulfur in Coal.

Created in 1984, the Ohio Coal Development Office has a coal technology program with $100 million in bond authorization. Twenty-three proposals, representing $293 million in private funds, recently competed in a recent coal project solicitation.

In the 1970's Kentucky embarked on an aggressive coal research and development program. An Energy Development and Demonstration Trust Fund was established in 1974, primarily to develop a coal-synthetic fuel industry. However, as the federal government's interest and support in synfuel development faded, Kentucky's biggest effort in coal research and development was to contribute $10 million to the 160-megawatt atmospheric fluidized bed combustion demonstration plant at the TVA Shawnee facility. Kentucky made its last payment to TVA for the fluidized bed project in 1990.

Testimony on two proposed coal projects at the last meeting of the Subcommittee on Energy underscored the lack of a funding source for promising clean coal projects in the state. Backers of the two projects were looking to the state for financial support to demonstrate their patented clean coal technologies. One of the proposed projects would remove sulfur from coal through a microwave process, "burning" the sulfur without burning the coal. This process could be completed before coal delivery to the power plant. The other project, a coal refining process, would thermally crack the coal to make a thick, oil-like liquid boiler fuel, as well as a number of marketable byproducts, including methanol.

Kentucky does continue to fund basic coal research at the university level, primarily through the University of Kentucky's Center for Applied Energy Research. Initial work on this study by the Energy Task Force included a tour of the facilities at the Center for Applied Energy Research and a review of research being conducted there. The center's research includes coal liquefaction, fluidized bed combustion, coal cleaning, conversion of coal to carbon materials and other high-value products, and coal combustion byproducts. The center is also studying issues relating to acid deposition and global warming.

The center has made concerted efforts to attract outside funding, including federal and private dollars, for its coal projects. It has landed contracts from the state research and development programs of Illinois, Ohio, and Pennsylvania. In the last two years, the center has garnered $11.7 million in external funding, using $3.62 million in matching state funds.[30] These moneys will be expended over the next several years.

In discussion with members of the Energy Task Force during the tour, the director of the Center for Applied Energy Research suggested that a concerted joint effort on coal research by coal industry and utilities needs to be initiated. He stressed the importance of attracting federal research monies to Kentucky to focus on the specific research needs of Kentucky coal.

Export Markets

Political and economic developments in other parts of the world, particularly Europe, present new opportunities in the export market for all U.S. coal, including Kentucky coal. First of all, decline in the value of the dollar in comparison with other currencies makes U.S. coal more competitive in many areas of the world. Secondly, privatization of the electric industry in Great Britain and the emergence of the European Economic Community will eliminate or reduce government subsidies for domestic coal and create new demand for foreign coal. And thirdly, other foreign interests which will be competing for these markets - South Africa, Australia, and South America - may be much closer to reaching their full export capability than is the United States. The Energy Information Administration projects that by 2010, U.S. steam coal exports (the type of coal used for industrial boilers and electric generation) to Europe will be over nine times their 1989 level.[31]

This export market is particularly important to Kentucky because it represents a chance to recoup some of the state's coal markets that may be lost to the CAAAs. Most Kentucky coal now going to foreign markets is low-to-medium sulfur coal from eastern Kentucky coalfields. But the world-wide spread of scrubbers and clean coal technologies is fueling new demand for lower-priced high-sulfur coal. Scrubber installations on coal-fired plants in Germany, the Netherlands, and Denmark have already triggered an increase in U.S. high-sulfur coal exports. Announcements of new major scrubbing programs by Canada, Italy, and Great Britain, and successful marketing of advanced clean coal technologies in Pacific Rim countries are expected to further increase high-sulfur coal exports.

Recognizing this window of opportunity, Kentucky held its first world coal trade mission in Berlin, Germany, on October 21, 1991, in conjunction with an international coal conference (Coal Trans 91). The Governor was accompanied to Germany by top officials in his administration, including three cabinet secretaries; the Jefferson County judge/executive; and representatives of major coal producers and transporters. The subcommittee was briefed by the Governor's Assistant for Coal and Energy Policy on the coal trade mission and Kentucky's opportunity to increase its coal exports.

State Support Services for Coal

The leading state agency for coal promotion and support services is the Governor's Office for Coal and Energy Policy. This office was created to replace a cabinet-level agency (Executive Order 89-396) and confirmed by the 1990 General Assembly (Senate Bill 97). In addition to its broader directive on general energy-related issues, this agency is charged with responsibility to: (1) conduct and coordinate coal-related scientific, technical and economic research; (2) provide assistance to small coal operators; (3) implement solutions for improving coal transportation; and (4) increase state coal production and markets. Primary activities of this office in recent months includes tracking clean air compliance decisions by utility buyers of Kentucky coal, publishing a series of coal resource reports; and organizing the coal trade mission to Germany.

With establishment of the Kentucky Coal Authority, the 1990 General Assembly created a resource which, if fully utilized, could significantly expand coal support services. The Kentucky Coal Authority is a public corporation with a membership which includes the chief executive officers of some of the state's largest coal companies. Duties of the Authority, pursuant to KRS 152A.315, include conducting research and analyses of potential markets for Kentucky coal, tax structures, and regulatory requirements, and developing public information and educational programs to improve public perception and understanding of coal and the coal industry. The authority is to recommend to the Governor projects and programs to protect and expand Kentucky coal markets. The office also has the authority to issue revenue bonds for coal development projects.

The authority got off to a slow start, holding only one meeting during the 1990-1991 interim. The group focused their attention on those Kentucky coal markets immediately "at risk," due to the CAAAs, and appointed a subcommittee to work on the issue.

The Governor's Office for Coal and Energy Policy currently staffs the Kentucky Coal Authority. This office has eight people working full-time in a technical or analytical capacity on coal-related activities. In testimony before the Subcommittee a representative of the Governor's Office for Coal and Energy Policy indicated that the office's resources are stretched, and that there is a need to increase its analytical capabilities.

It was the Governor's Task Force for Marketing Kentucky Coal, established at the same time the Governor's Office for Coal and Energy Policy was created, that recommended creation of a coal authority. That task force also recommended that resources of the Governor's Office for Coal and Energy Policy be increased, to expand the office's capability to deal with acid rain and global climate change issues and to enable effective functioning of the coal authority. However, the 1990 budget did not provide increased resources to this office.

In testimony made to the subcommittee, the Executive Assistant for the Governor's Office for Coal and Energy Policy indicated that the office is stretched to its limits and needs additional resources to be able to ensure that opportunities in the foreign coal market are realized, to evaluate new clean coal technologies, and to effectively deal with the global climate change issue.

Assistance for Displaced Workers

Based on the LRC economic analysis - and despite the welcomed news that TVA will continue to burn west Kentucky coal, the Subcommittee on Energy felt it necessary to consider available resources and a strategy to apply if large pockets of unemployment are triggered by the CAAAs. The subcommittee contacted the Department for Employment Services, the Workforce Development Cabinet, and the Economic Development Cabinet and asked them to identify their resources and any plans made to assist workers displaced by the federal acid rain legislation.

As administrator of the Jobs Training Partnership Act (JTPA) in Kentucky, the Department for Employment Services is expected to be the lead agency to develop strategy. The department is already at work identifying miners dislocated for any reason, including the CAAAs. The Training and Employment Division of the department receives notices of any layoffs affecting 15 or more employees. Statistics will be kept specifically on layoffs due to the CAAAs.

The department is working with unions, employers, and local officials to develop services to address layoffs from coal and coal-related industries - whether the layoffs are directly related to the CAAAs or not. It has applied for $3.3 million in JTPA discretionary funds for this purpose. However, the department has delayed any decision on applying for the estimated $50 million to be available through JTPA for CAAAs-related job losses until regulations for that program are promulgated.

An important resource to affected regions will be the department's Rapid Response Team, which can be dispatched to any area in the state to inform affected workers, unions, and employers of dislocated workers of services available in the area. Other training resources identified were the Bluegrass State Skills Corporation, the Workforce Development Cabinet's Tech System, vocational technical schools, adult education, and the community college system.

CHAPTER VI

Findings and Recommendations

The task assigned to the Tourism Development and Energy Task Force and its Subcommittee on Energy was an exceedingly difficult one. Members were fully cognizant that Kentucky's two coal-producing regions will be affected differently by the CAAAs and by actions taken in response to the CAAAs. Priority was given to those west Kentucky coal markets believed to be most immediately at risk. Much time and effort was spent on the clean air compliance plans of one utility, TVA, not only because it is west Kentucky's largest coal buyer, but also because it was felt that the decisions made by TVA, the largest utility in the country, would influence decisions of others in the industry. Once TVA made the announcement that it would continue to burn west Kentucky coal, efforts were focused on other issues. Actions which the federal government could take to make the CAAAs more equitable were identified. Available resources within this state to devote to coal and utility industries' compliance with the CAAAs were carefully analyzed. A need for increased research on foreign markets, clean coal technology, and coal combustion waste was also recognized. On November 12, 1991, the Tourism Development and Energy Task Force received a final report from the Subcommittee on Energy and adopted the following findings and recommendations.

1. Finding. In passing Title IV of the Clean Air Act Amendments of 1990, Congress placed a burden on certain regions of this country to solve what Congress defined to be a national problem. The Tourism Development and Energy Task Force believes Congress should reconsider the severe impacts certain coal regions of this nation face and should initiate new cost-sharing actions to encourage more utilities to install environmental control devices. Such action would protect more of Kentucky's coal in its western region and would reduce electric costs for consumers of Kentucky's affected utilities.

(a) **Recommendation. The Kentucky Congressional Delegation should be petitioned to work for passage of: (a) a tax credit to utilities which purchase environmental control devices to comply with the Clean Air Act Amendments of 1990; and (b) an amendment to the Federal Tax Reform Act of 1986 to restore tax-free status to pollution control bonds issued specifically for compliance with Title IV of the Clean Air Act Amendments of 1990.**

2. Finding. It appears that most of Kentucky's in-state coal markets will not suffer under initial implementation of the Clean Air Act Amendments of 1990 and that west Kentucky's largest coal buyer, the Tennessee Valley Authority, will not decrease its purchase of the region's coal. However, Kentucky may still face losses in out-of-state coal markets. The Tourism Development and Energy Task Force finds that it is much more difficult to affect the decisions of out-of-state coal buyers. The task force further finds that it would be both costly and unfair to Kentucky utilities to selectively subsidize the purchase of Kentucky coal for out-of-state buyers.

3. Finding. The Governor's Office for Coal and Energy Policy, which also staffs the Kentucky Coal Development Authority, is underfunded and understaffed. The coal marketing activities of this office are crucial to reaching the out-of-state coal buyers, identifying promising clean coal technologies, and promoting a better image for coal.

(a) **Recommendation. The 1992 General Assembly should increase funding for the Governor's Office for Coal and Energy Policy.**

(b) **Recommendation. The Governor's Office for Coal and Energy Policy should be required by statute to develop strategies for the promotion of Kentucky coal as an environmentally responsible fuel and to issue a report to the General Assembly annually. The report should include: (1) identification of existing coal markets; (2) identification of any changes or potential changes in coal markets; (3) any recommendations on how the state might pre-**

serve its existing markets and attract new ones; and (4) identification of any coal-related research or demonstration projects which the state should consider assisting.

4. Finding. Although unsure of the magnitude, the Tourism Development and Energy Task Force believes west Kentucky may see serious losses in coal mining jobs. Mines with medium to high-sulfur coal in eastern Kentucky may also face shutdown. Kentucky needs a well-developed strategy to meet the needs of displaced coal miners and deal with economies disrupted by the Clean Air Act Amendments of 1990.

(a) **Recommendation. If the BR 430 proposal, which would return more severance tax monies to coal-producing counties, is adopted by the General Assembly, the bill should be amended to allow those severance tax monies allocated for economic development to be used for a coal-related project, if that project will protect a Kentucky coal market from displacement under the Clean Air Act Amendments of 1990.**

(b) **Recommendation. There should be created and funded a regional economic development office in west Kentucky, similar to the East Kentucky Economic Development and Jobs Creation Corporation.**

(c) **Recommendation. The Department for Employment Services should act as the lead agency to: develop a strategy to counteract negative employment effects of the Clean Air Act Amendments of 1990; work with the Economic Development Cabinet, the Workforce Development Cabinet, the Labor Cabinet, Area Development Districts, and the United Mine Workers; and apply for all federal funds available to address such reduced employment.**

5. Finding. Utilities with operating facilities in this state who choose to install scrubbers or clean coal technologies in order to continue to burn local coal contribute greatly to the state's economy. For this reason, as well as to keep electric costs as low as possible, these utilities need to be helped whenever possible, to implement their clean air compliance plans in the least costly manner.

(a) **Recommendation. A new section of KRS Chapter 278, relating to public utilities, should be created to assure regulated electric utilities prompt and full recovery of costs associated with installation of scrubbers or clean coal technologies.**

(b) **Recommendation. The state's universities should be encouraged to pursue research on the characteristics of and alternative uses for coal combustion waste.**

(c) **Recommendation. The Transportation Cabinet should be directed to initiate new pilot projects on the use of coal combustion byproducts, particularly scrubber sludge, in its road construction activities.**

(d) **Recommendation. The Finance and Administration Cabinet, as the chief procurement agency of the state, and the Economic Development Cabinet should be directed to find new markets for coal combustion byproducts.**

(e) **Recommendation. The Natural Resources and Environmental Protection Cabinet should be directed to facilitate disposal of coal combustion waste in abandoned mine sites.**

(f) **Recommendation. State regulations on coal combustion utility waste, classified as special waste pursuant to KRS 224.868, should ensure protection of the environment but be no more stringent than federal law dictates.**

6. Finding. Kentucky has traditionally been a strong supporter and contributor of clean coal technology research and should continue in this role. The Clean Air Act Amendments of 1990, the threat of CO_2 reduction initiatives, and the bad image coal has in some areas of the country, make it imperative that efforts to accelerate clean coal technology and coal byproduct development research be accelerated. Coal producers, utilities, and other industries should also be called on to help fund research. The

state's primary coal research laboratory, the Center for Applied Energy Research at the University of Kentucky, is doing an outstanding job attracting external funding and could be tapped to increase clean coal research efforts.

(a) Recommendation. **A 20% income tax credit against donations made to the Center for Applied Energy Research by utilities, coal producers, and any other corporate entity should be established.**

7. Finding. Due to the Clean Air Act Amendments of 1990, Kentucky coal, more than ever before, faces strong competition on all fronts: from western U.S. states, particularly Wyoming; from the neighboring states of Virginia and West Virginia; and from foreign coal.

(a) Recommendation. **All state laws, tax policies, regulations, and regulatory procedures affecting the state's coal industry should be reviewed and recommendations for changes should be made to ensure Kentucky's ability to compete in domestic and foreign coal markets.**

8. Finding. The task force recognizes that its review of the issue was done in the very early stages of compliance with the new clean air law. Much can change in the coming months. The task force also believes global warming is an emerging issue which, potentially, could have an even greater negative impact on the state's coal industry.

(a) Recommendation. **The General Assembly and its interim committees should continue to monitor the effects of the acid rain provisions of the Clean Air Act Amendments of 1990, and should monitor global warming initiatives calling for significant reduction of CO_2.**

FOOTNOTES

1. National Acid Precipitation Assessment Program, *Annual Report and Findings Update*, June 1990, pp. 41 and 43.

2. The Oversight Review Board of the National Acid Precipitation Assessment Program, *The Experience and Legacy of NAPAP*, April 1991, p. 11.

3. *Ibid*, p. 8.

4. "Special Report: Clean Air Mandates," *Inside EPA's Clean Air Report*, 10 December 1990, p. 1.

5. U.S. EPA, "Title IV," *Clean Air Act Amendments of 1990, Detailed Summary of Titles*, 30 November 1990, p. 2.

6. Governor's Office for Coal and Energy Policy, *Western Kentucky Coal 1990-1991*, June 1991.

7. "Clean States Can Defer Elections of Bonus Allowances Under Clean Air Compliance," *Environmental Reporter*, 22, No. 10 (91), p. 557.

8. Telephone interview with Bob Columbo, Director for the Office of Worker Retraining and Adjustment Programs, U.S. Department of Labor, 8 August 1991.

9. For example, see "The Clean Air Act and Bonus Allowances," *Public Utilities Fortnightly*, 15 May 1991, and the Clean Air Act Amendments of 1990, Section 416(c), 42 USC 7651.

10. Energy Information Administration, "Coal Industry Developments," *Quarterly Coal Report*, January-March 1991, p. 13.

11. U.S. Government Accounting Office, *Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives, Fossil Fuels: Outlook for Utilities Potential Use of Clean Coal Technologies*, GAO/RCED-90-165, May 1990, p. 5.

12. U.S. Government Accounting Office, *Report to the Chairman, Subcommittee on Overnight and Investigation, Committee on Energy and Commerce, House of Representatives, Electricity Supply: Older Plants' Impact on Reliability and Air Quality*, GAO/RCED-90-200, September 1990, pp. 21-22.

13. Energy Information Administration, *Coal Production 1990*, DOE/EIA-00118(89), U.S. Department of Energy, November 1990.

14. Energy Information Administration, *Annual Outlook for U.S. Coal 1990*, DOE/EIA-0333(90), U.S. Department of Energy, March 1990.

15. Cobb, James C., James C. Currens, and Harry G. Enoch, *Compliance Coal Resources in Kentucky*, Kentucky Geological Survey, University of Kentucky, 1982.

16. *Ibid.*

17. These economic effects include impacts on the industrial sector, reduced cost of environmental damage, and changes in public sector expenditures. Industrial entities may be affected by choosing to enter the market for sulfur dioxide allowances. Improvements in environmental quality as a result of the CAAA would have associated economic benefits. Finally, changes in coal production will have public sector and fiscal impacts beyond changes in taxes generated through coal-related economic activity. These impacts would include state expenditures that related directly to the coal industry, such as coal-haul road damage and mine safety and environmental enforcement.

18. "New Law Provides Tax Incentives for Utilities to Install Scrubbers," *Environmental Reporter*, 22, No. 12 (1991), p. 667.

19. Governor's Office for Coal and Energy Policy, pp. 11-1 and v-1.

20. Oliver Kingsley, President of TVA Generating Group, at press conference held in Frankfort, Kentucky, on October 10, 1991.

21. Governor's Office for Coal and Energy Policy, p. v-5.

22. Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191(90), p. 65.

23. Governor's Office for Coal and Energy Policy and the Kentucky Coal Association, *Kentucky Coal Facts*, 15 November 1989, p. 41.

24. Energy Information Administration, *Coal Production 1990*, DOE/EIA-0118(90), p. 37.

25. "Fossil Fuel Proposed Tax to Thwart Global Warming," *Coal and Synfuels Technology*, 12, No. 41 (1991), p. 4.

26. "Eastern Europe Seen as Hot Clean Coal Market," *Coal and Synfuels Technololgy*, 11, No. 9 (1990), p. 6.

27. Congressional Quarterly Online Systems, search conducted 7 November 1991.

28. Robert Gentile, "Changing the Tide of Public Opinion," *Inside Environment*, September 1990.

29. Mary Joan Martin, "Illinois Develops Clean Coal Technologies," *Coal*, 96, No. 8 1991, p. 43.

30. Telephone interview with Don Challman, Administrative Staff Officer, UK Center for Applied Energy Research, 21 October 1991.

31. Energy Information Administration, *Annual Outlook for U.S. Coal 1991*, DOE/EIA-0333(91), July 1991, p. 13.

APPENDIX A

CORRESPONDENCE FROM ENERGY INFORMATION AMINISTRATION

Department of Energy
Washington, DC 20585

APR 25 1991

Ms. Donna A. Cantrell
Assistant Staff Economist
Legislative Research Commission
Frankfort, KY 40601

Dear Ms. Cantrell:

Thank you for your letter of April 3, 1991, requesting information on the Energy Information Administration's coal forecasts. In response, my staff has prepared the enclosed tables detailing our reference case forecasts and the impacts of the Clean Air Act Amendments of 1990 on Kentucky coal production, consumption, and prices. These projections are based on the analysis which was done for the Annual Energy Outlook 1991 and the forthcoming "Annual Outlook for U.S. Coal 1991," scheduled for publication in June.

Please note that these detailed State forecasts have not undergone as thorough a review as the national and regional projections published in the above-referenced documents. They should, therefore, be used more cautiously.

I hope that this is responsive to your request. If you have any further questions, please contact Dr. Richard Newcombe of my staff at (202) 254-5370.

Sincerely,

Scott Sitzer

Scott Sitzer
Chief, Coal Data Analysis and
Forecasting Branch
Energy Information Administration

Enclosure

Table 1. Projected Coal Production and Minemouth Prices for Kentucky: 2000 and 2010

Eastern Kentucky

	Sulfur Content	**2000**	**2010**
Production (million short tons per year)	Low	74	88
	Medium	73	85
	High	6	13
	Total	154	186
Minemouth Prices (1990 $ per short ton)	Low	$40.73	$48.27
	Medium	$32.19	$39.15
	High	$26.98	$30.76
	Total	$36.09	$42.90

Western Kentucky

	Sulfur Content	**2000**	**2010**
Production (million short tons per year)	Low	0	0
	Medium	1	1
	High	36	46
	Total	36	47
Minemouth Prices (1990 $ per short ton)	Low	$0.00	$0.00
	Medium	$30.54	$36.11
	High	$25.74	$29.50
	Total	$25.83	$29.63

Table 1. Projected Coal Production and Minemouth Prices for Kentucky: 2000 and 2010 (contd.)

Kentucky (Total)

	Sulfur Content	2000	2010
Production (million short tons per year)	Low	74	88
	Medium	74	86
	High	42	58
	Total	190	233
Minemouth Prices (1990 $ per short ton)	Low	$40.73	$48.27
	Medium	$32.17	$39.12
	High	$25.93	$29.77
	Total	$34.13	$40.24

Source: Energy Information Administration

Notes: Based on Annual Energy Outlook 1991 Reference Case.
Assumes effects of Clean Air Act Amendments of 1990.
Definitions of sulfur categories:
Low sulfur: up to 0.60 pounds per million Btu
Medium sulfur: 0.61 to 1.67 pounds per million Btu
High sulfur: greater than 1.67 pounds per million Btu

Table 2. Projected Coal Consumption and Delivered Prices for Kentucky: 2000 and 2010

Kentucky (Total)

	Sulfur Content	**2000**	**2010**
Consumption (million short tons per year)	Low	12	17
	Medium	10	10
	High	16	16
	Total	38	43
Delivered Prices (1990 $ per short ton)	Low	$46.26	$53.28
	Medium	$34.28	$35.99
	High	$29.30	$33.23
	Total	$35.86	$41.69

Source: Energy Information Administration

Notes: Based on Annual Energy Outlook 1991 Reference Case. Assumes effects of Clean Air Act Amendments of 1990. Definitions of sulfur categories:

- Low sulfur: up to 0.60 pounds per million Btu
- Medium sulfur: 0.61 to 1.67 pounds per million Btu
- High sulfur: greater than 1.67 pounds per million Btu

Table 3. Projected Impacts of the Clean Air Act Amendments of 1990 on Coal Production and Minemouth Prices for Kentucky: 2000 and 2010

Eastern Kentucky

	Sulfur Content	2000	2010
Production (million short tons per year)	Low	8	3
	Medium	0	1
	High	-1	-1
	Total	7	4
Minemouth Prices (1990 $ per short ton)	Low	$ 4.81	$ 8.27
	Medium	$ 1.91	$ 4.55
	High	($ 3.78)	($ 2.27)
	Total	$ 3.26	$ 5.91

Western Kentucky

	Sulfur Content	2000	2010
Production (million short tons per year)	Low	0	0
	Medium	-1	-1
	High	-19	-15
	Total	-20	-16
Minemouth Prices (1990 $ per short ton)	Low	$0.00	$0.00
	Medium	($ 1.93)	($ 0.29)
	High	($ 2.65)	($ 2.17)
	Total	($ 2.65)	($ 2.15)

Table 3. Projected Impacts of the Clean Air Act Amendments of 1990 on Coal Production and Minemouth Prices for Kentucky: 2000 and 2010 (contd.)

Kentucky (Total)

	Sulfur Content	**2000**	**2010**
Production (million short tons per year)	Low	8	3
	Medium	0	0
	High	-21	-15
	Total	-13	-12
Minemouth Prices (1990 $ per short ton)	Low	$ 4.81	$ 8.27
	Medium	$ 1.85	$ 4.49
	High	($ 2.76)	($ 2.14)
	Total	$ 2.50	$ 4.57

Source: Energy Information Administration

Notes: Definitions of sulfur categories:
- Low sulfur: up to 0.60 pounds per million Btu
- Medium sulfur: 0.61 to 1.67 pounds per million Btu
- High sulfur: greater than 1.67 pounds per million Btu

Table 4. Projected Impacts of the Clean Air Act Amendments of 1990 on Coal Consumption and Delivered Prices for Kentucky: 2000 and 2010

Kentucky (Total)

	Sulfur Content	**2000**	**2010**
Consumption (million short tons per year)	Low	4	8
	Medium	2	0
	High	-7	-9
	Total	-1	-1
Delivered Prices (1990 $ per short ton)	Low	$ 4.72	$ 7.73
	Medium	($ 0.18)	($ 1.16)
	High	($ 2.61)	($ 2.10)
	Total	$ 1.86	$ 3.93

Source: Energy Information Administration

Notes: Definitions of sulfur categories:
Low sulfur: up to 0.60 pounds per million Btu
Medium sulfur: 0.61 to 1.67 pounds per million Btu
High sulfur: greater than 1.67 pounds per million Btu

Department of Energy
Washington, DC 20585

JUN 14 1991

Ms. Donna Cantrell
Assistant Staff Economist
Legislative Research Commission
Frankfort, KY 40601

Dear Ms. Cantrell:

Thank you for your letter of May 8, 1991, requesting information on the Energy Information Administration's coal forecasts. In response, I have prepared the enclosed tables detailing our reference case forecasts for the years 1995, 2000, 2005, and 2010 as published in the Annual Energy Outlook 1991 (AEO91) and the forthcoming "Annual Outlook for U.S. Coal 1991." These tables include the impacts of the Clean Air Act Amendments of 1990 on production and price.

To confirm our telephone conversation of May 8, the modeling system which produced the AEO91 included the assumptions that underground mining labor productivity would increase at 2.0 percent per year, while surface mining labor productivity would increase at 1.0 percent per year. These assumptions are invariant over all regions and through the year 2010. For your convenience, Coal Production 1989 shows (Tables 28 and 29) that 1989 East Kentucky surface mine labor productivity was 2.92 short tons per miner hour, while West Kentucky surface mine labor productivity was 4.53 tons per hour. Deep mine labor productivity was 2.40 tons per hour (East Kentucky) and 3.13 tons per hour (West Kentucky). These are the most recent historical data currently available.

Please note that the enclosed detailed State forecast has not undergone as thorough a review as the national and regional projections published in the above-referenced documents. They should, therefore, be used more cautiously.

I hope that this is responsive to your request. If you have any further questions, please contact me at (202) 254-5370.

Sincerely,

Richard Newcombe

Richard Newcombe
Operations Research Analyst,
Coal Division
Energy Information Administration

2 Enclosures

KENTUCKY COAL PRODUCTION & IMPACTS OF THE CLEAN AIR ACT AMENDMENTS OF 1990:1995, 2000, 2005, AND 2010.
(MILLIONS OF SHORT TONS PER YEAR)

REGION	DEEP MINE PROD'N	DEEP MINE IMPACT	STRIP MINE PROD'N	STRIP MINE IMPACT	TOTAL MINE PROD'N	TOTAL PROD'N IMPACT
** YEAR 1995						
E.Kentucky	96.02	2.32	49.97	1.44	145.99	3.76
W.Kentucky	41.92	0.47	7.52	0.10	49.44	0.57
Total	137.94	2.79	57.49	1.54	195.43	4.33
** YEAR 2000						
E.Kentucky	105.26	6.84	48.30	0.17	153.56	7.01
W.Kentucky	32.23	-15.15	4.06	-4.44	36.29	-19.59
Total	137.49	-8.31	52.36	-4.27	189.85	-12.58
** YEAR 2005						
E.Kentucky	126.37	6.84	44.34	0.08	170.71	6.92
W.Kentucky	33.72	-13.75	7.17	-3.96	40.88	-17.72
Total	160.09	-6.91	51.51	-3.88	211.59	-10.80
** YEAR 2010						
E.Kentucky	130.55	1.81	55.58	1.78	186.13	3.59
W.Kentucky	36.84	-12.03	9.74	-3.48	46.59	-15.51
Total	167.39	-10.22	65.32	-1.70	232.72	-11.92

NOTE: Price and production figures given are from the **Reference Scenario** in the Annual Energy Outlook 1991 and include the impacts of the Clean Air Act Amendments of 1990. To obtain price and production figures based on identical assumptions without these impacts, subtract the impact figures from the adjacent price and production values. All prices shown are minemouth data.

KENTUCKY COAL PRICES AND IMPACTS OF THE CLEAN AIR ACT AMENDMENTS OF 1990: 1995,2000,2005,2010
($1990 PER SHORT TON)

REGION	DEEP MINE $/TON	DEEP MINE IMPACT	STRIP MINE $/TON	STRIP MINE IMPACT	TOTAL MINE $/TON	TOTAL PROD'N IMPACT
** YEAR 1995						
E.Kentucky	32.21	1.18	30.31	0.82	31.56	1.05
W.Kentucky	26.50	-0.10	27.27	0.19	26.62	-0.05
Total	30.47	0.80	29.91	0.74	30.31	0.78
** YEAR 2000						
E.Kentucky	36.52	3.33	35.14	3.02	36.09	3.26
W.Kentucky	25.81	-2.59	25.99	-2.95	25.83	-2.65
Total	34.01	2.38	34.43	2.79	34.13	2.50
** YEAR 2005						
E.Kentucky	41.49	5.25	39.55	4.19	40.99	4.99
W.Kentucky	27.85	-2.51	28.73	-2.14	28.01	-2.45
Total	38.62	4.05	38.04	3.58	38.48	3.94
** YEAR 2010						
E.Kentucky	43.48	6.25	41.54	5.13	42.90	5.91
W.Kentucky	29.52	-2.09	30.02	-2.37	29.63	-2.15
Total	40.41	4.73	39.82	4.20	40.24	4.57

NOTE: Price and production figures given are from the Reference Scenario in the Annual Energy Outlook 1991 and include the impacts of the Clean Air Act Amendments of 1990. To obtain price and production figures based on identical assumptions without these impacts, subtract the impact figures from the adjacent price and production values. All prices shown are minemouth data.

Department of Energy
Washington, DC 20585

SEP 2? 1991

Ms. Donna A. Cantrell
Assistant Staff Economist
Legislative Research Commission
State Capitol
Frankfort, KY 40601

Dear Ms. Cantrell:

This is in response to Senator David Boswell's letter of July 30, 1991, requesting information on the methodology used to develop estimates of the impact on Kentucky coal production and prices of the Clean Air Act (CAA) Amendments of 1990. At his request, I am directing my response to your attention.

With regard to the modeling process, the estimates provided to you in our letter of April 25, 1991, utilized the output of the Annual Energy Outlook Forecasting System. The specific models pertinent to coal and electricity estimates are the Coal Supply and Transportation Model (CSTM), the Electricity Market Module (EMM), the Resource Allocation and Mine Costing (RAMC) Model, and the National Coal Model (NCM). I have enclosed summary descriptions of the CSTM and NCM, and a copy of the Energy Information Administration's (EIA) model directory which contains abstracts of the other two models.

In general, the data used in the models are regional in nature, and do not refer to specific generating units or coal mines. Instead, data reported to EIA by electric utilities and coal producers are aggregated prior to their use in the models. The regional aggregations differ, however; for the EMM, both North American Electric Reliability Council regions and Federal Regions are used, depending upon the variables being treated; for the CSTM, the RAMC, and the NCM, more disaggregated supply and demand regions are used, as described in the enclosures.

With regard to the level of detail of output, the regional aggregations as described above are generally available; no unit-by-unit detail is available.

Finally, supplies of coal are estimated using schedules which relate prices to production for each type of coal available within each of the 32 supply regions. These schedules are known as "supply curves." They are derived based on the Demonstrated

Reserve Base of coal, EIA estimates of recoverability, and the costs of mining coal from both current and required future mines. The supply curves are calculated by the RAMC and then used in the CSTM and NCM.

With regard to the questions from the Governor's Office of Coal and Energy Policy, I am enclosing detailed computer forecasts from the CSTM for 1995, 2000, 2005, and 2010 for the requested regional projections, both base case (with the CAA) and without the CAA. The supply information is provided in tabular format for each year; the consumption and distribution information is provided in the enclosed copies of the CSTM detailed listings. I have also enclosed a description of how to interpret the detailed CSTM listings. Historical data for 1990 are shown in the enclosed table from Coal Production 1990. No price or production data by sulfur content are available. For demand and distribution data for 1990, I have enclosed a copy of the Quarterly Coal Report, October-December 1990, which provides summary information on the demand, cost, and origin of coal delivered to electric utilities and other coal-consuming sectors during 1990.

Following are responses to the remaining questions from the Governor's Office:

- Imports are exogenously treated. They are based on a 1986 study, Outlook for U.S. Coal Imports, a copy of which is enclosed. No further evaluation of imports in light of the CAA has yet been done. While the cost of Central Appalachian coal may indeed increase relative to current prices, the quantity of coal imported will not be fully determined by market forces alone. Although imports are somewhat sensitive to market price conditions, they are also influenced by the desire of consumers to maintain reliable sources of supply, quality considerations, and other government policies. These factors could tend to reduce import tonnages below the levels associated with predictions by market forces alone.

- The model is sensitive to changes in assumptions, as illustrated in the enclosed cases. In terms of Eastern Kentucky low-sulfur coal, the changes in price are due to increased demand, which induces the opening of new mines with higher capital and mining costs which must be recovered. It is not possible to meaningfully quantify the relative contributions of increasing mining costs versus higher coal demand since they are inter-related issues of supply and demand. We have not run cases which specifically change only coal exports or changes in transportation costs, and therefore cannot provide you with sensitivities at this time.

- Following are the assumed operating and maintenance costs for utilities in Kentucky, with and without scrubbers. All costs are in 1987 mills per kilowatt-hour:

	With Scrubbers	Without Scrubbers
East Kentucky	1.7	1.2
West Kentucky	1.7	1.3

Following are the initial capital costs for scrubbers assumed by the model, in 1987 dollars per kilowatt of capacity, for each State Implementation Plan (SIP) modeled (no capacity is assumed for SIP1 in East Kentucky):

	SIP1	SIP2	SIP3
East Kentucky	---	144	233
West Kentucky	235	202	303

Each SIP contains a share of electric utility capacity, categorized by current emission rates of sulfur dioxide. For example, SIP1 capacity currently has the lowest rate, while SIP3 has the highest.

- The model incorporates the cap on utility emissions through the NCM, which employs a linear programming algorithm to compute the least-cost configuration of utility capacity and dispatching to meet demands, subject to other constraints. One of those constraints is the cap on sulfur dioxide emissions for utilities. The model incorporates allowance sales among utilities by allowing the constraint to operate at the national level, thus allowing each supply region to trade allowances. The price of an allowance is an outcome, rather than an assumption of the model, and represents the marginal cost of sulfur dioxide reduction. These rates are $550 per ton in the year 2000 and $700 per ton in the year 2010, based on the latest model runs. The model does not incorporate allowances from the 3.5 million ton reserve.

- In the 1995 CAA run, approximately 1 gigawatt of additional utility capacity in Kentucky is retrofitted with scrubbers. We are unable to determine which specific unit or units this capacity represents. Since the Paradise unit currently scrubs coal, it is assumed that it will continue during the life of the plant.

Please note that the detailed State forecasts in the enclosures have not undergone as full a review as the national or regional projections published in the Annual Energy Outlook 1991 or the Annual Outlook for U.S. Coal 1991. They should, therefore, be used more cautiously.

In addition, I would like to clarify that our models are primarily national in scope, and are not intended to be extensively used at the detailed regional level. Although representations of States and other disaggregated regions are made within the models, they are for the purpose of building the national forecasts with as much detail as is reasonably possible, not for separate use themselves. It is possible that localized markets and conditions not captured by our models might impact Kentucky in ways different from the Nation as a whole.

I hope that this is responsive to your request. If you have any further questions, please contact Mr. Scott Sitzer at (202) 254-5300.

Sincerely,

Robert Schnapp

Robert M. Schnapp
Director, Coal Division
Energy Information Administration

15 Enclosures

APPENDIX B

UTILITY PLANTS RECEIPT OF KENTUCKY COAL

Electric Utilities Ranked by Sulfur Content of Coal Receipts
East Kentucky Coal, 1989

State	Utility	Plant	Tons	% of Total Tons	BTU	Sulfur as % of Weight	Estimated* Sulfur Dioxide per million Btu	$/mmBt
CN	United Illuminating Co	Bridgeport Harbor	849,000	1.04	13,297	0.5	0.75%	2.15
NY	Central Hudson Gas and Electric	Danskammer	401,168	0.49	13,238	0.5	0.76%	1.96
NY	Orange and Rockland Utilities	Lovett	140,400	0.17	13,065	0.5	0.77%	2.13
OH	Toledo Edison Co	Acme	5,200	0.01	13,066	0.6	0.92%	1.67
OH	Cleveland Electric Illum Co	Lake Shore	212,900	0.26	12,871	0.6	0.93%	2.13
NC	Carolina Power and Light	Mayo	49,200	0.06	12,911	0.6	0.93%	1.50
MO	Columbia Water and Light	Columbia	1,440	0.00	14,020	0.6	0.86%	2.12
WI	Wisconsin Public Service Corp	Pulliam	39,000	0.05	12,553	0.6	0.96%	1.59
MD	Baltimore Gas and Electric	Brandon Shores	608,000	0.74	12,888	0.7	1.09%	1.59
MS	Mississippi Power (Southern Co)	Watson	80,160	0.10	12,726	0.7	1.10%	1.51
FL	Gainesville Regional Utilities	Deerhaven	499,600	0.61	13,057	0.7	1.07%	1.74
FL	Orlando Utilities Comm	Stanton	1,074,263	1.32	12,723	0.7	1.10%	1.89
NJ	Public Service Elec and Gas-NJ	Mercer	300	0.00	12,997	0.7	1.08%	1.91
IN	Indiana Michigan Power (AEP)	Tanners Creek	658,000	0.81	12,597	0.7	1.11%	2.22
IN	Northern Indiana Public Service	Mitchell	214,500	0.26	12,845	0.7	1.09%	1.69
OH	Dayton Power and Light Co	Killen	380,500	0.47	12,439	0.7	1.13%	1.30
KY	Kentucky Utilities	Ghent	1,358,290	1.66	12,774	0.7	1.10%	1.56
OH	Hamilton, City of	Hamilton	11,198	0.01	12,265	0.7	1.14%	1.36
MS	Mississippi Power (Southern Co)	Daniel	1,105,160	1.35	13,031	0.7	1.07%	1.79
WV	Appalachian Power (AEP)	Mountaineer	210,400	0.26	12,156	0.7	1.15%	1.46
IL	Illinois Power	Havana	453,232	0.56	12,819	0.7	1.09%	1.44
IL	Central Illinois Light	Edwards	862,000	1.06	13,289	0.7	1.05%	1.79
IN	Northern Indiana Public Service	Rollin Schahfer	8,800	0.01	12,758	0.7	1.10%	1.83
KY	Tennessee Valley Authority	Shawnee	633,422	0.78	11,961	0.7	1.17%	1.25
Total Very-Low Sulfur Coal			**9,856,133**					
Percent of Total Shipments			**12.07%**					
WI	Madison Gas and Electric	Blount	3,000	0.00	13,477	0.8	1.19%	2.13
MI	Wisconsin Electric Power	Presque Isle	251,500	0.31	12,602	0.8	1.27%	1.47
WI	Manitowoc Public Utilities	Manitowocc	113,790	0.14	13,128	0.8	1.22%	1.78
NC	Duke Power	Allen	19,000	0.02	12,510	0.8	1.28%	1.70
NJ	Public Service Elec and Gas-NJ	Hudson	63,500	0.08	12,988	0.8	1.23%	1.82
MI	Consumers Power	Cobb-Sandusky Sg	457,400	0.56	12,478	0.8	1.28%	2.06
MD	Baltimore Gas and Electric	Wagner	36,000	0.04	12,959	0.8	1.23%	1.67
DE	Delmarva Powr and Light	Indian River	24,090	0.03	12,424	0.8	1.29%	1.77
NC	Duke Power	Dan River	74,000	0.09	12,785	0.8	1.25%	1.63
MI	Consumers Power	Karn-Weadock	577,000	0.71	12,375	0.8	1.29%	1.82
VA	Potomac Electric Power	Potomac River	273,000	0.33	12,758	0.8	1.25%	1.82
MI	Consumers Power	Weadock-Sandusky	265,300	0.32	12,348	0.8	1.30%	1.79
VA	Appalachian Power (AEP)	Clinch River	29,500	0.04	12,626	0.8	1.27%	1.27
MI	Consumers Power	Whiting	586,900	0.72	12,314	0.8	1.30%	1.91
OH	Columbus Div of Electricity	Refuse and Coal	38,500	0.05	12,991	0.8	1.23%	1.48
KY	East Kentucky Power Coop	Dale	199,700	0.24	12,203	0.8	1.31%	1.13
MI	Detroit Edison Co	Trenton Channel	325,000	0.40	12,786	0.8	1.25%	2.36
OH	Dayton Power and Light Co	Hutchings	114,000	0.14	12,092	0.8	1.32%	1.52
MN	Minnesota Power and Light	Aurora-Syl Laskin	1,300	0.00	12,754	0.8	1.25%	1.98
OH	Ohio Edison	Sammis	344,300	0.42	11,901	0.8	1.34%	1.19
WI	Dairyland Power Cooperative	Stoneman	1,500	0.00	12,969	0.8	1.23%	1.37
MI	Consumers Power	Campbell	1,642,700	2.01	12,615	0.8	1.27%	1.90

*Sulfur dioxide estimated by the following formula: % sulfur per million Btu = [(20,000)X(% sulfur by weight)/Btu per pound]

Electric Utilities Ranked by Sulfur Content of Coal Receipts
East Kentucky Coal, 1989

State	Utility	Plant	Tons	% of Total Tons	BTU	Sulfur as % of Weight	Estimated* Sulfur Dioxide per million Btu	$/mmBt
NC	Duke Power	Buck	66,000	0.08	12,770	0.8	1.25%	1.62
IN	Richmond Power and Light	Whitewater	20,850	0.03	11,832	0.8	1.35%	1.31
IL	Illinois Power	Wood River	51,956	0.06	12,391	0.9	1.45%	1.59
SC	Duke Power	Lee	278,000	0.34	12,336	0.9	1.46%	1.65
AL	Alabama Power Co (SC)	Barry	90,671	0.11	12,110	0.9	1.49%	1.47
MI	Lansing Board of Water & Light	Eckert	632,800	0.77	13,078	0.9	1.38%	1.86
KY	Kentucky Utilities	Tyrone	34,000	0.04	12,016	0.9	1.50%	1.19
SC	South Carolina Electric and Gas	Canadys	699,500	0.86	13,015	0.9	1.38%	1.70
OH	Cincinnati Gas and Electric Co	Miami Fort	527,100	0.65	11,918	0.9	1.51%	1.35
MA	New England Power (NEES)	Brayton	21,100	0.03	12,825	0.9	1.40%	1.38
MI	Lansing Board of Water & Light	Ottawa	4,800	0.01	13,283	0.9	1.36%	2.11
TN	Tennessee Valley Authority	Bull Run	2,247,336	2.75	11,485	0.9	1.57%	2.03
WV	Momongahela Power (APS)	Ft Martin	484,931	0.59	12,382	0.9	1.45%	1.95
GA	Savannah Electric and Power	Port Wentworth	160,907	0.20	12,714	0.9	1.42%	1.72
MI	Holland Board of Public Wks	James De Young	162,824	0.20	13,270	0.9	1.36%	1.69
FL	Florida Power Corp	Crystal River	4,059,088	4.97	12,670	0.9	1.42%	1.62
MI	Lansing Board of Water & Light	Erickson	347,300	0.43	13,061	0.9	1.38%	1.84
NC	Duke Power	Belews Creek	3,312,000	4.06	12,439	0.9	1.45%	1.82
VA	Appalachian Power (AEP)	Glen Lyn	21,300	0.03	12,938	0.9	1.39%	1.39
MI	Detroit Edison Co	Monroe	1,687,000	2.07	12,741	0.9	1.41%	2.06
MA	New England Power (NEES)	Salem Harbor	1,700	0.00	12,825	0.9	1.40%	1.38
MI	Detroit Edison Co	River Rouge	447,000	0.55	12,577	0.9	1.43%	1.97
MI	Detroit Edison Co	Harbor Beach	37,000	0.05	12,709	0.9	1.42%	2.53
MS	South Mississippi Elec Pwr Assn	R D Morrow	731,500	0.90	12,430	0.9	1.45%	1.99
VA	Virginia Electric and Power	Chesapeake	165,269	0.20	12,805	0.9	1.41%	1.58
SC	South Carolina Electric and Gas	Mcmeekin	176,700	0.22	12,916	1.0	1.55%	1.63
NC	Duke Power	Cliffside	606,000	0.74	12,561	1.0	1.59%	1.65
SC	South Carolina Electric & Gas	Williams	1,179,700	1.44	12,778	1.0	1.57%	1.68
NC	Duke Power	Marshall	1,196,000	1.46	12,463	1.0	1.60%	1.75
NC	Carolina Power and Light	Roxboro	2,881,300	3.53	12,684	1.0	1.58%	1.84
NC	Duke Power	Riverbend	88,000	0.11	12,391	1.0	1.61%	1.77
VA	VirginiaElectric and Power	Chesterfield	1,699,815	2.08	12,613	1.0	1.59%	1.53
GA	Savannah Electric and Power	McIntosh	404,108	0.49	12,389	1.0	1.61%	1.77
SC	South Carolina Electric & Gas	Wateree	852,000	1.04	12,779	1.0	1.57%	1.64
VA	Virginia Electric and Power	Possum Point	579,019	0.71	12,572	1.0	1.59%	1.56
FL	Jacksonville Electric Authority	St Johns River	1,203,930	1.47	12,674	1.0	1.58%	1.69
OH	Cincinnati Gas and Electric Co	Beckjord	1,132,000	1.39	11,545	1.0	1.73%	1.61
Total Low-Sulfur Coal			**33,731,484**					
Percent of Total			**41.31%**					
NC	Carolina Power and Light	Cape Fear	169,600	0.21	12,709	1.1	1.73%	1.93
NC	Carolina Power and Light	Sutton	363,200	0.44	12,567	1.1	1.75%	1.76
VA	Virginia Electric and Power	Bremo Bluff	424,648	0.52	12,772	1.1	1.72%	1.55
NC	Carolina Power and Light	Weatherspoon	124,000	0.15	12,510	1.1	1.76%	1.70
NC	Carolina Power and Light	Lee	220,500	0.27	12,737	1.1	1.73%	1.99
SC	South Carolina Public Serv Auth	Cross	1,347,825	1.65	12,488	1.1	1.76%	1.77
FL	Tampa Electric	Big Bend	2,103,771	2.58	12,844	1.1	1.71%	1.98
SC	South Carolina Public Serv Auth	Winyah	2,830,944	3.47	12,397	1.1	1.77%	1.77

*Sulfur dioxide estimated by the following formula: % sulfur per million Btu = [(20,000)X(% sulfur by weight)/Btu per pound]

Electric Utilities Ranked by Sulfur Content of Coal Receipts
East Kentucky Coal, 1989

State	Utility	Plant	Tons	% of Total Tons	BTU	Sulfur as % of Weight	Estimated* Sulfur Dioxide per million Btu	$/mmBt
FL	Tampa Electric	Gannon	453,571	0.56	12,769	1.1	1.72%	2.32
MD	Baltimore Gas and Electric	Crane	70,000	0.09	13,078	1.1	1.68%	2.24
SC	South Carolina Electric & Gas	Urguhart	337,000	0.41	12,736	1.1	1.73%	1.59
KY	East Kentucky Power Coop	Spurlock	767,000	0.94	11,779	1.1	1.87%	1.15
WV	Monongahela Power (APS)	Pleasants	4,820	0.01	11,344	1.2	2.12%	1.32
KY	Cincinnati Gas and Electric Co	East Bend	790,800	0.97	11,567	1.2	2.07%	1.54
AL	Alabama Electric Coop Inc	Lowman	124,520	0.15	11,438	1.2	2.10%	1.78
AL	Alabama Power Co (SC)	Gaston	8,942	0.01	12,579	1.2	1.91%	1.63
SC	Carolina Power and Light	Robinson	160,500	0.20	12,087	1.2	1.99%	1.71
GA	Georgia Power (Southern Co)	Wansley	64,500	0.08	12,504	1.2	1.92%	1.93
KY	Kentucky Power (AEP)	Big Sandy	2,636,200	3.23	11,906	1.2	2.02%	1.18
VA	Virginia Electric and Power	Yorktown	360,510	0.44	12,832	1.2	1.87%	1.56
OH	Dayton Power and Light Co	Stuart	5,393,900	6.61	11,516	1.3	2.26%	1.54
GA	Georgia Power (Southern Co)	Bowen	7,574,300	9.28	12,225	1.3	2.13%	1.69
WV	Monogahela Power (APS)	Willow Island	22,781	0.03	12,050	1.3	2.16%	1.19
FL	Lakeland Dept of Elec Wtr Utils	McIntosh	724,000	0.89	12,299	1.3	2.11%	2.12
GA	Georgia Power (Southern Co)	Atkinson	207,500	0.25	12,472	1.3	2.08%	1.55
TN	Tennessee Valley Authority	Kingston	1,539,531	1.89	12,445	1.3	2.09%	1.26
WV	Central Operating Co (AEP)	Sporn	355,600	0.44	11,850	1.3	2.19%	1.43
WI	Wisconsin Electric Power	Valley	127,200	0.16	12,676	1.4	2.21%	1.65
GA	Georgia Power (Sothern Co)	Harllee Branch	3,029,200	3.71	12,175	1.4	2.30%	1.57
OH	Toledo Edison Co	Bay Shore	392,400	0.48	13,373	1.4	2.09%	2.00
GA	Georgia Power (Southern Co)	Mitchell	308,000	0.38	12,523	1.4	2.24%	2.04
KY	East Kentucky Power Coop	Cooper	584,000	0.72	12,063	1.4	2.32%	1.15
SC	South Carolina Public Serv Auth	Jefferies	563,059	0.69	12,225	1.6	2.62%	1.83
TN	Tennessee Valley Authority	Cumberland	25,395	0.03	11,219	1.6	2.85%	1.25
TN	Tennessee Valley Authority	Sevier	719,597	0.88	12,317	1.6	2.60%	1.17
Total Medium-Sulfur Coal			**34,929,314**					
Percent of Total			**42.78%**					
TN	Tennessee Valley Authority	Johnsonville	1,337,773	1.64	11,379	1.7	2.99%	1.29
KY	Kentucky Utilities	Brown	633,090	0.78	11,917	1.8	3.02%	1.06
SC	South Carolina Public Serv Auth	Grainger	170,333	0.21	12,765	1.8	2.82%	1.68
GA	Georgia Power (Southern Co)	Yates	154,900	0.19	12,403	1.9	3.06%	1.58
FL	Seminole Electric Coop	Seminole	3,000	0.00	12,605	1.9	3.01%	1.66
AL	Tennessee Valley Authority	Widows Creek	366,770	0.45	11,888	2.0	3.36%	1.20
GA	Georgia Power (Southern Co)	Hammond	310,940	0.38	12,392	2.1	3.39%	1.47
GA	Georgia Power (Southern Co)	Arkwright	152,400	0.19	12,502	2.2	3.52%	1.57
KY	Louisville Gas & Electric	Mill Creek	1,900	0.00	11,315	2.2	3.89%	1.25
IA	Cedar Falls Utilities	Streeter	9,478	0.01	11,529	2.8	4.86%	1.27
Total High-Sulfur Coal			**3,140,584**					
Percent of Total			**3.85%**					
Total (Averages)		128 Plants	81,657,515	100	12,377	1.1		1.69

Source: Governor's Office for Coal and Energy Policy, Commonwealth of Kentucky

*Sulfur dioxide estimated by the following formula: % sulfur per million Btu = [(20,000)X(% sulfur by weight)/Btu per pound]

UTILITY PLANTS RANKED BY RECEIPT OF WESTERN KENTUCKY COAL (1989)

State	Utility	Plant	Tons	% Surface	% Spot	Btu	% Sulfur	% Ash	$/mmBtu
KY	Tennessee Valley Authority	Paradise	7,114,371	4.2	20.3	10,985	4.6	16.9	0.97
TN	Tennessee Valley Authority	Cumberland	5,247,622	78.6	0.0	11,542	2.8	8.2	1.29
KY	Louisville Gas and Electric	Mill Creek	3,248,100	92.2	57.9	11,492	3.0	10.4	1.14
IN	Indiana-Kentucky Electric Corp	Clifty Creek	3,175,000	61.9	14.3	11,635	3.4	11.2	1.03
FL	Tampa Electric	Big Bend	2,252,291	43.6	49.6	12,332	2.8	8.7	1.38
TN	Tennessee Valley Authority	Gallatin	1,906,623	3.8	16.5	12,033	2.7	9.2	1.38
KY	Big Rivers Electric Corp	R D Green	1,524,600	23.3	0.0	10,475	4.3	16.2	1.11
FL	Seminole Electric Coop	Seminole	1,393,000	0.0	26.0	12,437	3.0	9.3	1.90
AL	Tennessee Valley Authority	Widows Creek	1,227,078	15.3	65.7	11,685	3.5	11.0	1.13
KY	Big Rivers Electric Corp	D B Wilson	1,163,400	18.5	0.0	11,182	4.1	15.3	1.43
KY	Louisville Gas and Electric	Cane Run	914,800	90.1	57.5	11,511	3.0	10.4	1.17
KY	Kentucky Utilities	Ghent	882,730	93.3	95.9	11,332	2.7	9.3	0.92
GA	Georgia Power (Southern Co)	Atkinson-Mcdonough	736,600	96.4	4.0	11,773	2.9	10.3	1.67
OH	Cincinnati Gas and Electric Co	Miami Fort	692,500	81.7	32.2	11,340	2.4	9.4	1.35
KY	Owensboro Municipal Utilities	Smith	630,100	100.0	0.0	10,667	2.8	11.9	1.10
TN	Tennessee Valley Authority	Allen	614,489	100.0	0.0	11,699	2.0	7.6	1.18
KY	Big Rivers Electric Corp	Coleman	552,000	100.0	0.0	11,144	2.3	9.0	1.06
KY	Big Rivers Electric Corp	Reid-Henderson II	483,100	100.0	0.0	12,394	2.8	8.3	1.24
FL	Gulf Power	Crist	476,400	55.9	100.0	12,160	3.0	8.4	1.26
KY	Kentucky Utilities	Green River	451,160	98.2	100.0	11,813	2.3	8.1	1.02
KY	Cincinnati Gas and Electric Co	East Bend	431,300	82.5	20.1	11,335	2.6	9.8	1.36
GA	Georgia Power (Southern Co)	Wansley	424,900	74.8	41.9	11,857	2.9	9.4	1.50
KY	Tennessee Valley Authority	Shawnee	419,221	40.0	2.0	11,861	3.2	9.5	1.00
MS	Mississippi Power (Southern Co)	Watson	394,640	66.4	100.0	12,187	2.6	7.2	1.34
FL	Gulf Power	Scholtz	340,600	16.6	100.0	12,428	2.8	8.4	1.47
FL	Jacksonville Electric Authority	St Johns River	296,390	0.0	100.0	12,248	3.6	11.9	1.69
MO	Associated Electric Coop	Madrid	277,500	66.7	0.0	11,218	3.1	11.1	1.25
GA	Georgia Power (Southern Co)	Bowen	267,800	100.0	0.0	11,774	3.0	10.2	1.62
AL	Alabama Electric Coop Inc	Lowman	263,925	100.0	87.4	12,153	1.9	10.5	1.38
IL	Electric Energy	Joppa	158,500	91.3	93.1	11,301	2.4	10.4	1.15
GA	Georgia Power (Southern Co)	Yates	149,500	77.9	34.3	11,799	2.9	9.6	1.49
WI	Dairyland Power Cooperative	Genoa No 3	105,100	100.0	100.0	12,206	2.7	9.3	1.27
IN	Indiana Michigan Power(AEP)	Tanners Creek	101,400	77.9	100.0	11,729	2.9	9.6	1.19
FL	Gulf Power	Smith	100,400	4.6	100.0	12,445	3.0	9.5	1.29
OH	Dayton Power and Light Co	Killen	76,200	100.0	100.0	11,693	3.1	10.1	1.17
OH	Cincinnati Gas and Electric Co	Beckjord	63,700	97.5	21.5	11,275	2.6	9.9	1.51
IA	Interstate Power	Lansing	49,400	100.0	100.0	11,210	2.5	10.3	1.06
WV	Monongahela Power (AFS)	Pleasants	30,703	0.0	0.0	11,875	3.8	14.1	1.30
IN	Southern Indiana Gas and Elec	A B Brown	30,471	100.0	100.0	11,128	4.2	14.5	1.11
AL	Alabama Power Co (SC)	Greene	24,127	100.0	100.0	11,995	2.1	7.0	1.30
KY	Kentucky Utilities	Tyrone	21,750	100.0	100.0	11,974	0.8	11.0	1.21
TN	Tennessee Valley Authority	Colbert	18,564	0.0	100.0	11,235	2.0	8.9	1.14
GA	Georgia Power (Southern Co)	Hammond	17,500	100.0	0.0	11,797	3.0	10.2	2.43
IA	Iowa Southern Utilities	Burlington	16,600	100.0	100.0	11,885	3.1	7.8	1.88
IL	Illinois Power	Wood River	7,141	100.0	100.0	12,631	1.1	7.6	1.67
MO	Union Electric	Sioux	6,000	33.3*	100.0	11,171	2.9	10.8	1.61
IN	Public Service Co of Indiana	Gallagher	2,900	100.0	100.0	10,495	2.5	12.4	1.46
TOTALS (AVERAGES)		**47 PLANTS**	**38,782,196**	**50.9**	**29.0**	**11,529**	**3.3**	**11.3**	**1.22**

Excerpted from "Western Kentucky Coal 1990-1991 (Draft)"
Kentucky Governor's Office for Coal and Energy Policy

APPENDIX C

ESTIMATING THE ECONOMIC IMPACT OF REDUCED PRODUCTION OF WESTERN KENTUCKY COAL

By Dr. Charles F. Haywood

Estimating The Economic Impact of
Reduced Production of Western Kentucky Coal

by

Dr. Charles F. Haywood, Director and Chief Economist
Center for Business and Economic Research
University of Kentucky

This paper is in response to current interest in the question of what the impact on the Kentucky economy would be if TVA elects to shift from Western Kentucky coal to compliance coal from sources outside Kentucky.

As there is uncertainty about the amount of production that might be lost, the following analysis is cast in terms of impact factors per one million tons of lost production. The analysis also illustrates how total impacts can be estimated by multiplying the impact factors by the number of million tons of lost production.

The impact factors are derived, in part, from existing tonnage and tax data. Also involved in the calculation of the impact factors are (1) several multipliers estimated by the U. S. Department of Commerce for measuring the economic impact of coal mining in Kentucky, and (2) several "rules of thumb" for estimating state tax collections. The analysis is on the conservative side; that is, we have sought to avoid overestimating any of the impacts and as a result have probably underestimated them.

The following discussion has three parts: Part I presents the economic impact factors per million tons of lost production. Part II estimates the impact on state tax collections. Part III discusses certain impacts that we cannot quantify and which would magnify the adverse impacts quantified in Parts I and II.

I

The economic impact of the loss of one million tons of coal production in Western Kentucky can be readily and conservatively estimated by using three impact multipliers estimated by the U. S. Department of Commerce's Bureau of Economic Analysis (BEA).

1. <u>Annual total output of goods and services in Kentucky would decrease by $49.65 million for every one million tons of lost coal production</u>.

At $24 per ton, the loss of one million tons of production of Western Kentucky coal would have a "direct" impact on the Kentucky economy of reducing total output by $24 million. To estimate the "total output" impact, the $24 million "direct" impact is multiplied by 2.0687, the total output multiplier estimated by BEA for coal mining in Kentucky. The resulting $49.65 million of reduction in total output includes $25.65 million of "indirect" or "derivative" impacts in addition to the "direct" impact of $24 million.

The "indirect" impacts derive from the successive rounds of reductions in spending by businesses and households that would occur as the initial $24 million reduction in coal sales works its way through the Kentucky economy. If faced with a reduction of $24 million in sales, the coal mining sector would necessarily reduce spending on wages and salaries, supplies, utilities, business services, equipment, and other inputs to the coal production process. Such reductions in spending by coal mining companies would, in turn, result in decreases in the outputs of businesses selling goods and services to coal companies and to their employees. These businesses, also in turn, would necessarily reduce their spending on wages and salaries, supplies, utilities, business services, equipment, and other inputs, and another round of decreases in outputs would occur. The multiplier of 2.0687 is the BEA's estimate of the end result of the successive rounds of changes in spending in response to an initial change of 1.0 in the coal mining sector. When the initial change is a $24 million decrease, the end result is a total decrease of $49.65 million.

2. Annual earnings of households and individuals in Kentucky would decrease by $14.51 million for every one millions tons of lost coal production.

This estimate is obtained by multiplying the "direct" impact of $24 million by the BEA's estimate that 0.6044 is the earnings multiplier relevant to an impact originating in the coal mining sector in Kentucky. Included in the $14.51 million are both "direct" and "indirect" impacts, i. e., losses of earnings of households and individuals directly impacted by the loss of one million tons of coal production and losses of earnings of households and individuals indirectly impacted through the successive rounds of reduced spending for goods and services.

3. The employment effect would be a loss of 631 jobs, of which 161 would be in the coal mining sector and 470 in other sectors of the Kentucky economy, for every one million tons of lost coal production.

The estimate of 631 jobs is obtained from the BEA's estimate that a change of $1 million in sales of coal in Kentucky results in a change of 26.3 in the number of employed persons. That is, the 631 is obtained by multiplying 26.3 by 24, the number of millions of dollars of lost coal sales associated with a reduction of one million tons of production. The estimate of 161 coal mining jobs lost per million tons of reduced production is based on data supplied by the coal companies. The implied employment multiplier of 3.92 seems reasonable in view of the fact that coal mining jobs are among the highest paying of industrial and commercial jobs.

The total output, earnings, and employment multipliers used in the above analysis were published by the U. S. Department of Commerce in Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (Washington, DC: U. S. Government Printing Office, May 1986). Attached to this memorandum are copies of the title page, table of contents, and the page showing the Kentucky multipliers. These multipliers, in our opinion, are useful because they come from a source not related to any particular industry and because they are careful, conservative estimates. Also, multipliers of this type tend to be relatively stable over long periods of time.

By way of summary, a loss of one million tons of annual coal production in Western Kentucky would result in a decrease of $49.65 million in the annual total output of the Kentucky economy. Included in that decrease of $49.65 million would be a decrease of $14.51 million of earnings of households and individuals. Associated with the declines in output and earnings would be a loss of 631 jobs.

Estimates of the decreases that would result from losses of production in excess of one million tons can be obtained by multiplying these three impact factors by the number of millions of tons of lost production. For example, a loss of, say, 4 million tons would result in decreases of $198.6 million of annual total output, $58.04 million of annual earnings, and 2,524 jobs. A loss of, say, 8 million tons would result in decreases of $397.2 million of annual total output, $116.08 million of annual earnings, and 5,048 jobs. A loss of, say, 10 million tons would result in decreases of $496.5 million of annual total output, $145.1 million of annual earnings, and 6,310 jobs. A loss of, say, 18 million tons would result in decreases of $893.7 million of annual total output, $261.2 million of annual earnings, and 11,358 jobs.

II

For every one million tons of coal production lost in Western Kentucky, annual state tax collections would decrease by approximately $3.15 million. This estimate includes taxes lost directly from the coal mining sector and taxes lost as a result of the indirect impacts on total output and earnings described above. The specific tax losses are set forth below.

Tax Losses Per One Million Tons of
Lost Coal Production

a. $1,080,000 of severance tax
b. 288,000 of sales tax paid by mining companies
c. 365,652 of sales tax paid by households
d. 507,870 of sales tax related to total output effect
e. 526,750 of personal income taxes
f. 384,000 of business income and other taxes

$3,152,272 of total state taxes, or $3.15 million

The bases for these estimates are described in Notes to Part II at the end of this paper.

Estimates of decreases in annual tax collections associated with losses of production in excess of one million tons can be obtained by multiplying $3.15 million by the number of millions of tons lost. For example, the loss of, say, 4 million of annual production would reduce annual collections of state taxes by $12.6 million (4 times $3.15 million). The loss of, say, 8 million tons would reduce annual tax collections by $25.2 million. The loss of, say, 10 million tons would reduce annual tax collections by $31.5 million. The loss of, say, 18 million tons would reduce annual tax collections by $56.7 million.

III

The foregoing analysis has not taken into account several kinds of additional impacts which are very difficult to estimate. Some weight should be given to the additional impacts.

Any significant decline in sales of Western Kentucky coal to TVA has adverse implications for sales of Western Kentucky coal in general. A decrease in production will increase average cost of production per ton because the fixed costs of producers will need to be spread over a smaller number of tons of output. Such increase in average cost would force producers to try to increase price in a market that is highly competitive. There would almost certainly be some further loss of sales and further curtailment of production. The result might even be a vicious downward spiral of sales and production, ending in cessation of operations by one or more producers.

A decrease in sales of Western Kentucky coal would result not only in a decrease in state tax revenues but also an increase in certain types of state expenditures, including but not limited to unemployment compensation, AFDC, Medicaid, and social service programs in general.

There would also be adverse impacts on local government revenues and expenditures. Such impacts would be concentrated in some 10 to 12 counties in Western Kentucky, with severe effects being felt in at least 6 of them.

A good deal more study would be needed to estimate these additional impacts within a narrow range. Our judgment is that these additional impacts could increase the impacts quantified in Parts I and II by between 20 percent and 50 percent.

A further effect that we have not tried to estimate would be the "feedback" effect on TVA itself and on the municipal and cooperative organizations engaged in the distribution of electric power in the impacted area. That is, electric power sales would decrease as a result directly of any reduction in annual coal production and as a result indirectly of the multiplier effects described above. Further study of a somewhat detailed nature would be required to estimate such "feedback" effect, and TVA would be an essential source of relevant information. It may be that TVA has already estimated the likely "feedback" effect as part of its decision-making on the question of switching to compliance coal to be produced by sources outside TVA's service area.

Notes to Part II

The following notes are keyed to the letters a through f denoting the various tax sources estimated in Part II above.

a. The estimate of severance tax was calculated by multiplying the assumed average price per ton of Western Kentucky coal sold to TVA ($24) by 4.5 percent, which is $1.08 per ton; then multiplying by one million ton. The severance tax data supplied by several Western Kentucky mining companies are consistent with this calculation.

b. The estimate of $288,000 of sales tax paid by mining companies per million tons of production was derived from data supplied by several Western Kentucky mining companies. The implication is that sales taxes are paid on approximately $4.8 million of goods and services purchased by mining companies in producing one million tons, or $24 million worth of coal. Such implication does not appear to be unreasonable.

c. The estimate of $365,652 for sales tax paid by households was based on assumptions that 70 percent of the $14.51 million of earnings would be available for spending after taxes and that 60 percent of such spending would be for goods and services subject to the sales tax of 6 percent.

d. The estimate of S507,870 for "sales tax related to the total output effect" assumes that 33 percent of the indirect total output effect (33% of $25.65 million) would consist of goods and services subject to the 6 percent sales tax and not included in c above.

e. The estimate of $526.750 of personal income tax was derived by calculating the state personal income tax that would likely be paid on income of $22,995 ($14.51 million of lost earnings divided by 631 lost jobs).

f. The estimate of $384,000 of business income and other taxes is based on data supplied by several mining companies, such data being extrapolated to other businesses likely to be impacted indirectly through the multiplier effects described in Part I.

REGIONAL MULTIPLIERS:
A User Handbook for the Regional Input-Output Modeling System (RIMS II)

May 1986

U.S. DEPARTMENT OF COMMERCE
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Washington, D.C. 20402

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Appendix Tables

Table B.--Total Multipliers, by Industry Aggregation, for Output, Earnings, and Employment

	Output/1/ (dollars)	Earnings/2/ (dollars)	Employment/3/ (number of jobs)
Agriculture, forestry, and fisheries:			
Agricultural products and agricultural, forestry, and fishery services	2.3882	0.5928	56.6
Forestry and fishery products	1.8772	.3436	27.1
Mining:			
Coal mining	2.0687	.6044	26.3
Crude petroleum and natural gas	1.4912	.2307	12.0
Miscellaneous mining	1.9425	.5419	31.5
Construction:			
New construction	2.3593	.7422	44.9
Maintenance and repair construction	2.3620	.8466	50.7
Manufacturing:			
Food and kindred products and tobacco	2.1296	.3496	24.4
Textile mill products	1.8217	.5071	34.6
Apparel	1.7853	.5086	40.4
Paper and allied products	1.9397	.4530	23.3
Printing and publishing	2.0203	.6160	35.9
Chemicals and petroleum refining	1.8925	.2873	13.8
Rubber and leather products	2.1464	.5173	28.1
Lumber and wood products and furniture	2.0581	.5610	37.9
Stone, clay, and glass products	2.1708	.5973	31.9
Primary metal industries	2.2670	.5098	23.2
Fabricated metal products	2.2358	.6233	32.6
Machinery, except electrical	2.2211	.6224	30.9
Electric and electronic equipment	2.2986	.5813	29.5
Motor vehicles and equipment	2.3701	.4803	22.2
Transportation equipment, except motor vehicles	2.0803	.6062	27.1
Instruments and related products	2.0723	.6363	36.8
Miscellaneous manufacturing industries	2.1675	.5851	37.2
Transportation, communication, and utilities:*			
Transportation	2.1824	.7912	40.1
Communication	1.5627	.4271	20.7
Electric, gas, water, and sanitary services	1.9342	.3244	15.3
Wholesale and retail trade:			
Wholesale trade	1.9351	.6845	38.6
Retail trade	1.9828	.7711	62.1
Finance, insurance, and real estate:			
Finance	1.8230	.5652	33.3
Insurance	2.1131	.7283	38.3
Real estate	1.3315	.1252	10.3
Services:			
Hotels and lodging places and amusements	1.9599	.5719	60.4
Personal services	2.0736	.7605	74.4
Business services	1.9688	.7973	60.4
Eating and drinking places	2.1268	.5922	62.9
Health services	2.1328	.8989	50.3
Miscellaneous services	2.2376	.7069	44.7
Households	1.2430	.3537	25.6

* Includes government enterprises.

1. Each entry in column 1 represents the total dollar change in output that occurs in all row industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.

2. Each entry in column 2 represents the total dollar change in earnings of households employed by all row industries for each additional dollar of output delivered to final demand by the industry corresponding to the entry.

3. Each entry in column 3 represents the total change in number of jobs in all row industries for each additional 1 million dollars of output delivered to final demand by the industry corresponding to the entry.

SOURCE.--Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division, Bureau of Economic Analysis.

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