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Examination of Utility Phase I Compliance Choices and State Reactions to Title IV of the Clean Air Act Amendments of 1990

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Examination of Utility Phase I Compliance Choices and State Reactions to Title IV of the Clean Air Act Amendments of 1990

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PREFACE

The examination and analysis effort reported in this document began in January 1993, and an internal draft report was presented to the U.S. Department of Energy in July 1993. All analytical work was conducted before the U.S. Environmental Protection Agency (EPA) proposed revisions in the substitution and compensating unit program for Phase I units under Sections 404(b) and 408(c) of Title IV of the Clean Air Act Amendments (CAAA) of 1990. In some instances, potential program changes may influence utility Phase I compliance choices. These potential changes are not reflected in the analysis reported here, and modifications caused by EPA's proposed revisions are not included in the Phase I unit database discussed in this report.

Previously, a unit designated as a substitution unit would have received allowances* equal to that unit's baseline† multiplied by the unit's actual or allowable 1985 emission rate. A utility seeking to use the substitution program would be required to document that the same or a greater level of emission reduction would be accomplished through unit substitution rather than controls on the Phase I unit in question. If the EPA determined that no increase in sulfur dioxide (SO_2) emissions would result, then an acid rain permit would be granted under Section 408. A unit designated as a compensating unit would also become an "affected" unit.§ It would receive allowances on the basis of the reduced generation from the original Phase I unit and the compensating unit's baseline multiplied by the lower of the actual or allowable 1985 SO_2 emission rate.

The EPA proposed revisions to the substitution program, including changes in the allowance allocation calculations for substitution units, in September 1993. The allowances would be calculated by use of the lesser of (1) 1990 actual emission rate or (2) allowable federal or state emission limits in effect when the 1990 CAAA were enacted. In some cases, the new calculations would lower the number of allowances allocated to substitution units. The reduction in allocated allowances might necessitate more stringent emission controls for an affected unit or additional allowance purchases for a utility with substitution plans.

The proposed treatment of reduced utilization is more complicated. A Phase I unit would identify one or more units to compensate for a reduction in generation by the original unit. These compensating units would be allocated allowances based on their baselines and actual (or allowed) emission rates. At the end of the year, the actual reduction in generation from the Phase I unit and the increase in generation from the compensating units would be

* Each allowance represents the limited right to emit one ton of sulfur dioxide during a specified year.

† The term "baseline" refers to the annual quantity of fossil fuel consumed by an affected unit, measured in millions of British thermal units (Btu) in a year designated by Title IV regulations.

§ Being considered an "affected" unit implies that the unit is regulated under the conditions of Title IV.

calculated. If the Phase I unit did not reduce generation or if the compensating units did not increase generation, no allowances would be granted to the compensating units.

The EPA has indicated that a public statement regarding the proposed revisions would be issued in early November 1993. However, the issues involved will likely end up in litigation. Therefore, final resolution of the substitution/compensating unit issues will likely depend on the court's interpretation of Sections 404(b) and 408(c) of Title IV.

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ACKNOWLEDGMENTS

The authors wish to recognize Dr. J. Roger Morris (U.S. Department of Energy, Office of Environmental Analysis) for sponsoring the preparation of this report and database and for his technical and administrative support. In addition, Dr. Derek Winstanley, director of the National Acid Precipitation Assessment Program (NAPAP), provided guidance and support that was instrumental throughout the project. Finally, the authors wish to acknowledge comments and technical input provided by Dr. Kenneth Rose (National Regulatory Research Institute), Robert Taub (General Accounting Office), Dr. Richard Winter (Argonne National Laboratory), and a host of state environmental and public utility commission staff.

NOTATION

The following is a list of the principal abbreviations, acronyms, and symbols used in this report.

AFUDC	allowance for funds used during construction
APC/FGD	advanced pulverized coal with improved flue gas desulfurization
APPI	Argonne Power Plant Inventory
Btu	British thermal unit(s)
CAA	Clean Air Act of 1970
CAAA	Clean Air Act Amendments of 1990
CBOT	Chicago Board of Trade
CCT(s)	clean coal technology(ies)
CO_2	carbon dioxide
CWIP	construction work in progress
DOE	U.S. Department of Energy
DSM	demand-side management
ECAR	Eastern Central Area Reliability Agreement
EPA	U.S. Environmental Protection Agency
FAC(s)	fuel adjustment clause(s)
FBC	fluidized bed combustion
Fed. Reg.	Federal Register
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FIFO	first in, first out
GW	gigawatt(s)
HAP(s)	hazardous air pollutant(s)
IGCC	integrated coal gasification with combined cycle
IRP	integrated resource planning
IRS	Internal Revenue Service
lb	pound(s)
LCP	least-cost planning
LIFO	last in, first out
LILCO	Long Island Lighting Company
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MMBtu	million British thermal units
MW	megawatt(s)

NAPAP	National Acid Precipitation Assessment Program
NAS	National Academy of Science
NEPOOL	Northeast Power Pool
NERC	North American Energy Reliability Council
NOPR	Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NSPS	New Source Performance Standard
NYPP	New York Power Pool
PJM	Pennsylvania-New Jersey-Maryland (Interconnect)
PSC	public service commission
PSI	PSI Energy Inc.
PUC(s)	public utility commission(s)
RACT	reasonably available control technology
RTG	regional transmission group
SERC	Southeastern Electric Reliability Council
SIP(s)	state implementation plan(s)
SO_2	sulfur dioxide
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas (Power Pool)

EXAMINATION OF UTILITY PHASE I COMPLIANCE CHOICES AND STATE REACTIONS TO TITLE IV OF THE CLEAN AIR ACT AMENDMENTS OF 1990

by

K.A. Bailey, T.J. Elliott, L.J. Carlson, and D.W. South

ABSTRACT

Title IV (acid rain) of the Clean Air Act Amendments of 1990 is imposing new limitations on the emission of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electric power plants. The act requires utilities to develop compliance plans to reduce these emissions, and indications are that these plans will dramatically alter traditional operating procedures. A key provision of the SO_2 control program defined in Title IV is the creation of a system of emission allowances, with utilities having the option of complying by adjusting system emissions and allowance holdings.

A compilation of SO_2 compliance activities by the 110 utility plants affected by Phase I is summarized in this report. These compliance plans are presented in a tabular form, correlated with age, capacity, and power pool data. A large number of the Phase I units (46%) have chosen to blend or switch to lower sulfur coals. This choice primarily is in response to (1) prices of low-sulfur coal and (2) the need to maintain SO_2 control flexibility because of uncertain future environmental regulations (e.g., air toxics, carbon dioxide) and compliance prices.

The report also discusses the responses of state legislatures and public utility commissions to the compliance requirements in Title IV. Most states have taken negligible action regarding the regulatory treatment of allowances and compliance activities. To protect mine employment, states producing high-sulfur coal have enacted regulations encouraging continued use of that coal, but for the most part, this response has had little effect on utility compliance choices.

SUMMARY

The central focus of this report is identification of sulfur dioxide (SO_2) control options being implemented by the electric utility industry to comply with Phase I of Title IV of the Clean Air Act Amendments (CAAA) of 1990 (Public Law 101-549). This focus includes development of a database of utility compliance strategies. In addition, state legislation and regulatory responses to the SO_2 program are described. Development of a database of state actions focused on states in which Phase I generating units are located, since those states will be the leaders in regulatory treatment of compliance options and the allowance market.

The Title IV SO_2 program is designed to reduce utility SO_2 emissions to approximately half of 1980 levels. The program is being implemented in two phases. Phase I begins January 1, 1995, and ends December 31, 1999. Phase I affects 110 of the highest SO_2-emitting generating plants in the nation. Phase II begins on January 1, 2000, and continues indefinitely. Almost all fossil-fuel burning electric utility units will be affected by Phase II. Control of emissions of nitrogen oxides (NO_x) from affected units will also be implemented in phases.

The SO_2 program uses emission allowances as its primary means of measuring program compliance. An "allowance" is the limited right to emit one ton of SO_2 during a specified year. Allowances may be (1) used to cover actual SO_2 emissions; (2) banked during the year they are allocated and then used or sold at a later date; (3) sold or leased to another party; or (4) bought and used to cover current emissions, banked for later use, or resold. Allowances may be freely transferred among units, regardless of the initial allocation.

Utility units can employ a variety of techniques to achieve systemwide compliance with Title IV SO_2 requirements. These techniques can be grouped into five general categories: (1) fuel alteration measures, (2) flue gas treatment, (3) boiler repowering, (4) altered generation dispatch, and (5) allowance compliance. These categories are not mutually exclusive; for example, a utility could use a flue gas treatment device and alter the unit's dispatch order. In fact, given the changes in relative marginal costs among utility units as they take measures to control SO_2 and NO_x emissions, dispatch order will certainty alter unit utilization for many utility systems. Compliance planning has occurred at the level of particular units, a utility's plants (system), and even on a power pool or regional basis. Unit strategies include fuel alterations, flue gas treatment, and boiler alteration. System or utility strategies include allowance offsets, altered dispatch, and conservation. On a power pool or regional level, strategies such as power purchases, allowance pooling, and integrated dispatch can aid in compliance planning.

Plans submitted by utilities indicate that the dominant Phase I compliance strategy selected has been fuel switching from high-sulfur coals to lower-sulfur eastern and western coals — 102 units were identified as fuel switching to lower sulfur coals (Figure S.1). On a smaller scale, fuel blending or trimming is being used to reduce the sulfur content of fuel at 20 units. Some of the 102 units that indicated fuel switching as a principal compliance strategy also intend to blend a variety of lower-sulfur coals.

Installation of flue gas desulfurization (FGD), whether a wet or dry technology, appears to be the second most frequently chosen compliance strategy for Phase I compliance. Twenty-six units will be constructing FGD controls in response to Phase I limits. The greatest use of this option is occurring in midwestern and eastern states that produce high-sulfur coal.

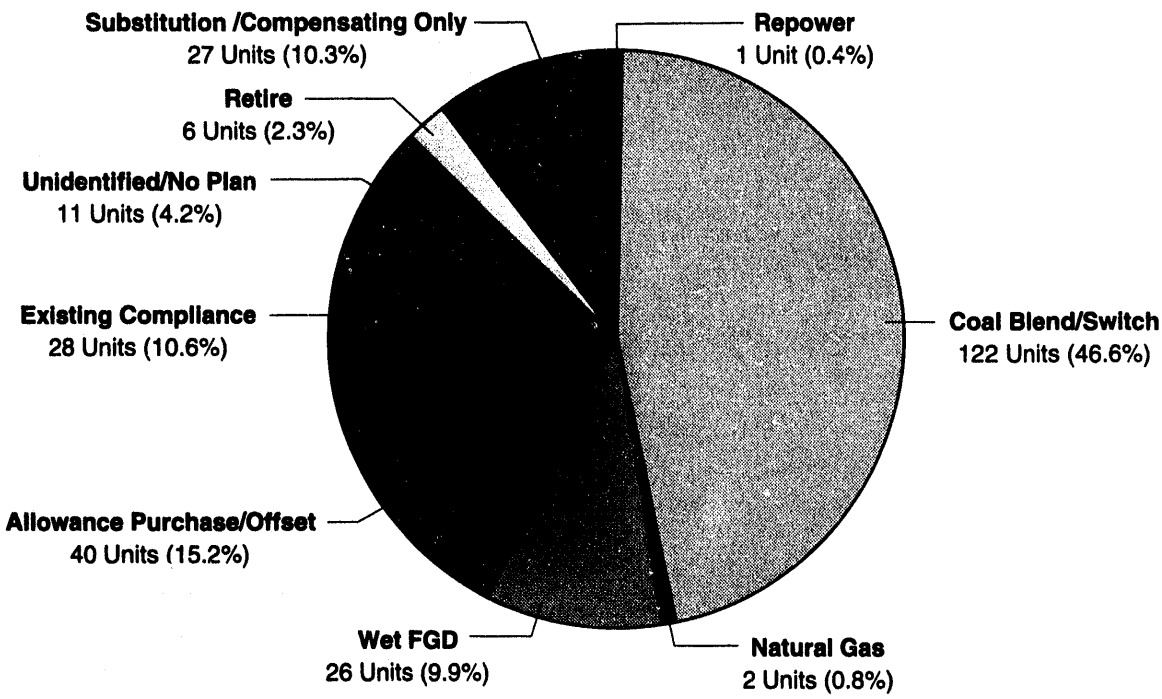

FIGURE S.1 Distribution of Phase I Compliance Options Selected by Affected Utilities

Among the units that will be affected by Phase I limits, 145 will employ substitution, reduced utilization, and/or altered dispatch programs to achieve compliance. Of these units, 56 are reducing unit utilization by relying on non-SO_2-emitting sources. Because of the increased generation costs resulting from installing FGD and altering fuels, dispatch will most likely be altered by most of the affected utility systems. Therefore, to a certain extent, all Phase I affected and not currently affected units will be impacted by Phase I compliance activities. Figure S.2 presents an overview of the compliance plans of those units selecting the substitution/compensating option in conjunction with other options.

Six units — four in Wisconsin, one in Indiana, and one in Ohio — will rely on retiring-unit offsets (i.e., credits earned by eliminating emissions through removal of generating units from service) to achieve Phase I compliance. None of these states has regulations in place that account for the retirements. All six retired units are over 40 years old. Five have capacities of about 100 megawatts (MW), and one has a capacity of about 400 MW. Thirty-one Phase I units will achieve compliance by obtaining allowances from system offsets. Finally, eight Phase I units will rely on allowance purchases as their primary means of achieving Phase I compliance.

Most states that have units affected under Phase I are engaged in integrated resource planning or some form of public-utility-sponsored resource forecasts. An important consideration for compliance planning has been state SO_2 actions in effect previous to the

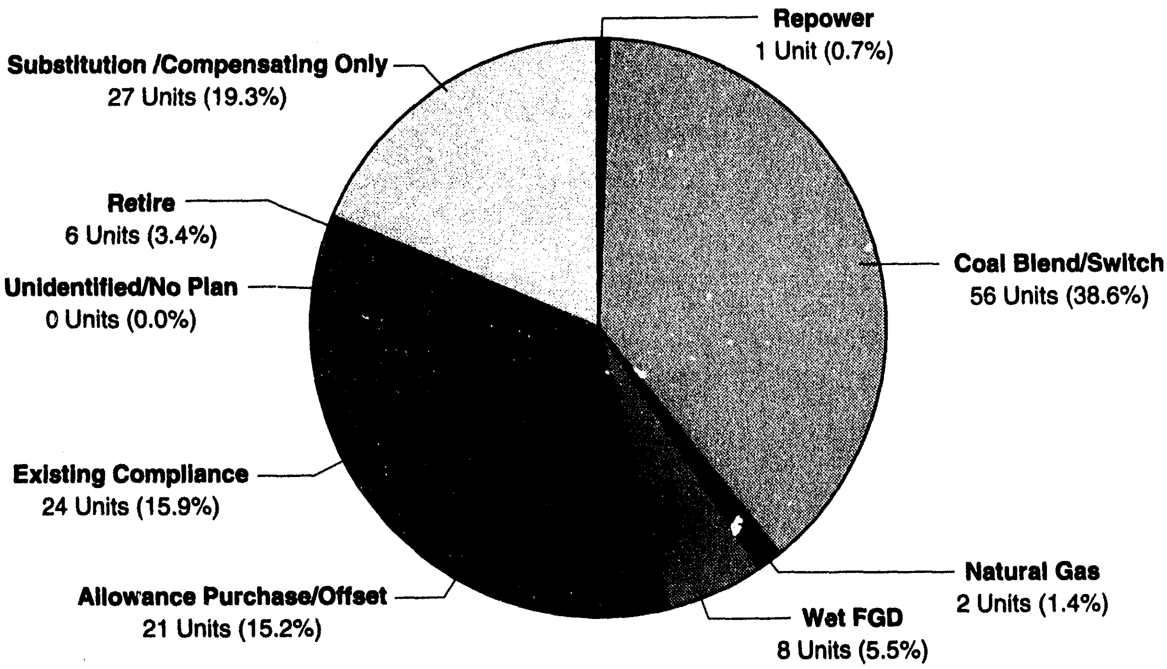

FIGURE S.2 Compliance Plans of Phase I Units Selecting the Substitution/ Compensating Option

CAAA. New York and Wisconsin had SO_2 control laws for several years before the CAAA were implemented. Therefore, units in those states are for the most part already in compliance and precluded from additional controls under Phase I. In addition, some units have already installed SO_2 controls in states with strict SO_2 emission limits.

One of the most contentious issues has been the use of state incentives and mandates to encourage the continued use of high-sulfur coals. States with high-sulfur coal reserves have enacted legislation favoring the use of in-state coal through preferential regulatory review and tax credits. States with such programs are Illinois, Indiana, Ohio, and Pennsylvania. These states, as well as West Virginia, all have taken an active role in promoting clean coal technologies (CCTs) through state coal development boards. The magnitude of the CCT promotions vary by state. Those states with a large level of generating capacity affected by Phase I have issued, or are in the process of developing, allowance trading and valuation rules. Rules have been approved in Ohio, Indiana, and Pennsylvania. Other states have also developed rules, but not as extensive as those in Ohio, Pennsylvania, and Indiana.

Several conclusions can be drawn from the utility compliance activities, state regulatory actions, and the discussion of the environmental and rate regulations. First, utilities are tending to choose those compliance strategies that provide the greatest compliance flexibility. Most units are relying on fuel switching, allowance offsets, and substitution/compensating units for system compliance. Relatively low compliance costs of these options (in most cases) combined with the ability of these units to alter compliance plans in Phase II without excessive difficulties make these options ideal. One potential concern is the number of utilities electing not to purchase allowances. Allowance transfers are tending to be used within utility systems. Part of this behavior is prompted by risk aversion and current regulatory structure and uncertainties. However, in some cases, allowances have a lower price than some compliance options (e.g., FGD applications and some fuel switching). Another factor encouraging regulatory flexibility is the future uncertainty of environmental controls on hazardous air pollutant emissions and carbon dioxide (CO_2). Second, few public utility commissions have issued detailed rulings on the treatment of allowances and utility compliance. In some cases, compliance rulings such as preapproval and direct passthrough of costs may lead to distortions in utility behavior. The utility commissions play a key role in developing a successful allowance market and influencing the overall cost of the Title IV acid deposition control program. Lack of utility commission actions may lead to overly costly utility compliance planning.

1 INTRODUCTION

Because of provisions of the Clean Air Act Amendments (CAAA) of 1990 (Public Law 101-549), the electric utility industry is undergoing its most profound changes in environmental control requirements since passage of the Clean Air Act (CAA) of 1970 (Public Law 91-604). The CAAA include (1) a program for the reduction of sulfur dioxide (SO_2) emissions, (2) new control requirements for emissions of nitrogen oxides (NO_x), and (3) possible controls on utility hazardous air pollutant (HAP) emissions. While these programs will contribute to reductions in acid deposition, improve visibility in certain areas, reduce urban ozone, and improve local air quality, they will also increase environmental compliance costs borne by the utility industry and, as such, are likely to alter generation and capacity acquisition patterns.

Of particular interest to policy makers, the environmental community, and industry is the introduction of marketable/tradable SO_2 emission allowances. (Each "allowance" represents a limited right to emit one ton of SO_2 during a specified year.) In contrast to the design and performance standards of previous emissions control policies, electric utilities affected by Title IV of the CAAA will be allowed to select their own "least cost" compliance strategy.

1.1 ISSUES TO BE EXAMINED

The central focus of this report is identification of SO_2 control options being implemented by the electric utility industry to achieve Phase I compliance. In addition, state legislation and regulatory responses to the SO_2 program are identified and described.

The data collected in this evaluation have been organized primarily into two databases. The first is a Utility Compliance Database that contains detailed information on Phase I compliance, with some additional Phase II and new-source information. The second is the State Regulatory Database identifying state actions affecting utility compliance choice. The two databases can be used in conjunction with each other.[1] This report describes the contents of the databases and discusses issues influencing compliance choice. Trade publications, including *Compliance Strategies Review*, *Electric Power Alert*, and *Utility Environment Reporter*, were used extensively. To verify and expand the utility database, the regional offices of the U.S. Environmental Protection Agency (EPA), the North American Energy Reliability Council (NERC) and state regulatory agencies were contacted. Because the report was compiled concurrently with EPA's preliminary inventory of utility Phase I compliance plans, some of the information will have to be revised or supplemented as more (and better) data become available. Phase II unit compliance strategies, although most are still in the preliminary stages, have been identified when information was available.

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[1] To obtain copies of these databases, contact Koby Bailey, Decision and Information Sciences Division, Building 900, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439.

The state actions database focuses on those states in which Phase I units are located, since these are the first states that will be required to address the regulatory treatment of compliance options and the allowance market. The information on state actions was gathered through a survey of the trade literature, with confirmation and elaboration by utility commissions and departments of environmental protection in the states most affected by Phase I requirements.

1.2 ORGANIZATION OF REPORT

Section 2 of the report reviews the Title IV SO_2 program and its incentives for environmental control. A review of the compliance strategies available to utilities and an overview of the compliance planning process are also presented. Section 3 discusses the databases of utility compliance and state regulatory actions as they relate to the national SO_2 program. Section 4 reviews the various types of programs being implemented at the state and federal levels to address utility compliance planning and the formation of the allowance market. Section 4 also presents an analysis of the possible effects of state regulatory actions on the functioning of the allowance market. Section 5 summarizes the issue of utility flexibility and the impact of other environmental controls on the utility industry. That section highlights compliance strategies that may decrease utility flexibility to respond to future environmental controls. Section 6 lists the references cited in this report, and Appendixes A and B list codes for the Utility Compliance and State Regulatory databases, respectively.

2 TITLE IV REQUIREMENTS AND UTILITY OPTIONS

Title IV of the CAAA will cause dramatic changes in the way electric utilities plan and operate their power plants. It establishes a two-part program directed at reducing SO_2 and NO_x emissions from coal-burning generating units. The NO_x program, which is similar to previous air quality policies, relies on emission standards to reduce emissions. Some flexibility has been introduced into the NO_x program through provisions that allow for averaging NO_x emissions across the individual units of a plant. The SO_2 program has undergone more radical restructuring because of the introduction of a marketable allowances program. This program will alter the compliance planning process by giving utilities a wider range of compliance options and the ability to develop a least-cost (portfolio) strategy.

2.1 SO_2 REQUIREMENTS AND PROGRAMS IN TITLE IV

The Title IV program is designed to reduce utility SO_2 emissions to approximately half of 1980 levels.[2] Utility units will be affected by the program requirements in two phases:

- *Phase I* — Under Phase I, a total of 110 power plants, each with generating capacities in excess of 100 megawatts (MW) and emission rates greater than 2.5 pounds (lb) SO_2 per million British thermal units (MMBtu),[3] have been designated as "affected units." Phase I emission reduction requirements will go into effect on January 1, 1995. Many of the affected plants contain more than one generating unit, so 263 Phase I units are listed by name in the CAAA.[4] The 263 units have a combined generating capacity of approximately 82,000 MW.

- *Phase II* — All U.S. fossil-fuel utility units will be affected by Title IV provisions beginning in 2000. According to EPA, more than 2,300 units will be affected by Phase I and Phase II combined.[5] Future Phase II units represent a total generating capacity of about 377,600 MW.

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[2] Title IV control requirements apply to all fossil fuel combustion units with a nameplate capacity greater than 25 MW [Section 402(8)]. However, any third party, including brokers, may hold allowances for any purpose. In addition, industrial sources of SO_2 can "opt into" the program and earn credits to sell by making reductions in their SO_2 emissions.

[3] Classifications and standards expressed in Btu measure the amount of energy consumed by a utility unit; classifications and standards expressed in MW measure the unit generating capacity.

[4] Section 404, Table A.

[5] 57 *Fed. Reg.* 29,940 (July 7, 1992), 57 *Fed. Reg.* 30,034 (July 7, 1992). The authors of this report estimate that the total number is 2,456 units.

Allowances will serve as the benchmark for determining whether units are in compliance with Phase I and Phase II requirements. Each affected unit will be allocated a fixed number of allowances on the basis of its baseline fuel consumption. As indicated above, each allowance represents a limited right to emit one ton of SO_2 during a specified year. The baseline is calculated as the average yearly fuel consumption for the period 1985-1987. In Phase I, the number of allowances allocated to a unit will be equal to 2.5 times the millions of Btu of fuel consumed in the baseline period divided by 2,000. In Phase II, the number of allowances allocated will be reduced to 1.2 times the millions of Btu consumed in the baseline period divided by 2,000. Additionally, Phase II imposes a 8.95-million-ton cap on utility SO_2 emissions — any future emissions arising from growth in power demand must be offset by reductions from the existing capital stock of power plants.

Allowances may be (1) used to cover actual current SO_2 emissions; (2) banked during the year they are allocated, then used or sold at a later date; (3) sold or leased to another party; or (4) bought and used to cover current emissions, banked for later use, or resold. Allowances may be freely transferred among units, regardless of the initial allocation.

In essence, a utility's decision process for each unit is constrained by the following requirement: *annual utility SO_2 emissions (tons) ≤ allowances held at year's end.* A utility that achieves this result at the end of each year through the proper procedures will have met the requirements of the Title IV SO_2 program. Thus, the objective of a utility that owns an affected unit (other than plant operators who may choose to violate compliance requirements) will be to adjust the two sides of the equation so as to achieve compliance. It is this process that gives utilities compliance flexibility under Title IV. Trading options are likely to become more prominent in Phase II, when both the number of available allowances and cost of compliance increase.

2.1.1 Phase I

Phase I establishes various compliance "incentive" programs for each phase, as well as some programs that address equity considerations. In Phase I, 200,000 allowances are allocated to units in Illinois, Indiana, and Ohio on the basis of each affected unit's pro rata share of all allowances allocated for all Phase I units in those states.[6] These additional allowances are provided to avoid excessive compliance burdens in these three states, which rely on high-sulfur coal.

The CAAA specify four additional programs that may be used by Phase I units in addition to other compliance options. First, a utility may "opt into" the Phase I extension program that delays compliance with Phase I requirements until January 1, 1997. A unit in this program must adopt a qualifying SO_2 control technology that reduces uncontrolled SO_2 emissions by 90% or more. The unit will receive additional allowances from a special

[6] Section 404(a)(3). The Kyger Creek, Clifty Creek and Joppa steam units are exempt from the program for both receiving the allowance allocations and for purposes of calculating pro rata shares.

allowance reserve (containing 3.5 million allowances) for subscribing to this program.[7,8] Second, a utility can reassign all or part of a Phase I unit's allowance allocation to a substitute unit, which makes both units "affected" under Phase I for purposes of Title IV. A utility might choose to substitute a Phase II for a Phase I unit, thus reducing SO_2 control costs. By virtue of the substitution, the Phase II unit also becomes an affected Phase I unit for Title IV NO_x requirements.[9] Third, a utility can choose to reduce its use of a Phase I unit and shift its generating load to an unaffected "compensating unit." However, if the utility reduces use of a Phase I unit and cannot explain where the capacity was shifted to, it must surrender allowances.[10] Finally, a utility can achieve SO_2 emissions reductions through energy conservation and renewable energy applications. Demonstrated emission reductions from the use of designated alternative energy "sources" will allow an affected unit to earn bonus allowances from the Conservation and Renewable Energy Reserve.[11] This program also exists for Phase II units.[12]

In addition to these special programs, utilities can select from a variety of control options in order to bring an affected unit into compliance. Some consideration has also been given to allowing power pools and integrated utility systems to behave as corporate entities in allocation of allowances for compliance purposes.

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[7] Section 404(d).

[8] The allocation of "scrubber" allowances for the extension program has been subject to significant debate. EPA originally envisioned using a telephone queuing system as opposed to a lottery or pro rata allocation mechanism, but ultimately decided to use a lottery approach to determine which parties will receive the special allowances. See 58 *Fed. Reg.* 15,634 (March 23, 1993).

[9] Sections 404(b) and (c).

[10] Legitimate utilization reductions that will be accepted by EPA include shifting to a designated compensating unit, identifying a sulfur-free generator (such as wind, solar or nuclear power source), use of an energy conservation mechanism (e.g., EPA's "Green Lights" program), or improving unit efficiency.

[11] Note that the *Federal Register* notice for this program contains an error; the date for installation is not 1993, as stated, but 1992. The reserve contains 300,000 allowances to be used for conservation or for biomass, solar, geothermal, or wind generation. Under Section 404(f)(2)B)(iv), an electric utility is to be guaranteed net income neutrality for qualified energy conservation measures so that there is no penalty to the utility for its conservation investments.

[12] Sections 408(c) and (d).

2.1.2 Phase II

Phase II will expand the scope of the SO_2 program to include the majority of existing utility units and all new units. Although Title IV primarily regulates units larger than 25 MW, Phase II also implements special emission limits for units smaller than 25 MW.[13]

In Phase II, a total of 50,000 allowances are to be allocated in the states of Alabama, Georgia, Illinois, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia.[14] These allowances will be allocated on a pro rata basis similar to the Phase I program. In addition, those states that experienced population growth of 25% or more between 1980 and 1988 and had more than 30 gigawatts (GW) of electrical generating capacity in 1988 will receive "high-growth-state" allowances.[15] Units in high-growth states will also receive additional allowances based on alternate fuel-use calculations. For each state with an average fossil fuel utility emission rate of less than 0.8 lb SO_2 per million Btu, additional allowances may be given if the state's governor chooses to accept them.[16]

Two other special programs will be available in Phase II. The Conservation and Renewable Resource bonus program will establish a pool of 300,000 allowances.[17] Phase II units will also have the option of repowering with certain clean coal technologies (CCTs),[18] and thus may receive a three-year extension on Phase II compliance until December 31, 2003.

2.1.3 Permitting Requirements

In conjunction with the permitting requirements of Title IV, utilities are required to report their plans to regional EPA offices and, in some cases, state regulatory bodies (e.g., Public Utility Commissions [PUCs] and state environmental agencies). Phase I compliance plans were due February 15, 1993. Phase II plans are due January 1, 1996.

2.2 UTILITY COMPLIANCE OPTIONS

Utility generating units have many options to achieve systemwide compliance with Title IV SO_2 requirements. These options can be grouped into five general categories: (1) fuel alteration measures, (2) flue gas treatment, (3) boiler repowering, (4) altered

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[13] Section 405(c).

[14] Section 405(a)(3).

[15] Section 405(i).

[16] Section 406(a).

[17] Section 408(c) and (d).

[18] Section 409.

generation dispatch, and (5) allowance compliance.[19] These categories are not mutually exclusive; for example, a utility could use a flue gas treatment device (e.g., scrubber) and alter the unit's dispatch order to achieve compliance. In fact, given the change in relative marginal costs among utility units that reduce SO_2 and NO_x emissions, dispatch order and unit utilization (capacity factors) will likely be altered for many utility systems.

Compliance planning can occur at the unit, plant, power pool, or regional level. Unit strategies include fuel alteration, flue gas treatment, and boiler alteration. System or utility strategies include allowance compliance and altered generation dispatch. For a power pool or regional level, strategies such as power purchase, allowance pooling, and integrated dispatch can constitute a compliance plan.

2.2.1 Fuel Alteration Measures

Fuel alteration measures include (1) fuel blending, (2) fuel switching, (3) natural gas co-firing, and (4) coal cleaning/beneficiation. In this case, fuel blending consists of blending various coal types and grades in order to reduce SO_2 emissions. Coal fuel blending is used to avoid the need for extensive boiler and control modifications and to provide a potentially lower cost alternative to fuel switching or flue gas desulfurization (FGD). The cost of fuel blending is low compared with other SO_2 control options; the primary determinants include the cost of (1) delivered low-sulfur coal to be blended, (2) modifying coal handling operations, (3) optimizing or modifying electrostatic precipitators (ESPs) or particulate collection systems, (4) disposing the additional fly ash that may be generated, and (5) changing generation because of altered fuel heating values.

The quantities of SO_2 emitted are directly related to the sulfur content of the fuel burned. Thus, switching from a fuel with a high sulfur content to a fuel with a low sulfur content will reduce SO_2 emissions. For the most part, the fuel switching[20] taking place is between high-sulfur and low-sulfur coals, although increased use of low-sulfur oil is expected at some units, particularly in the Northeast. While not a rule, most units that have engaged in fuel switching are those that have historically used Illinois Basin or higher sulfur Appalachian Basin coals. Most fuel switching has been to western low-sulfur coals from the Powder River and Colorado basins, or low-sulfur Appalachian coals.[21] Fuel switching may create some difficulties due to differences in ash content and heating value across coal types. Significant boiler and control modifications may be required to accommodate such differences.

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[19] For a more complete description of these compliance strategies and technologies see South et al. (1990).

[20] Unless stated otherwise, fuel switching should be considered synonymous with coal switching.

[21] Several midwestern Phase I units have indicated that they will make more extensive use of local low- and medium-sulfur coal resources.

Natural gas — the cleanest of the fossil fuels available for use in electric power generation — can be co-fired with coal or, in some cases, used seasonally as a primary fuel. Uncertainty over supply and future prices is cited as the chief reason for not using this option, although the flexibility and low emissions associated with natural gas may offset these problems to some extent.

Coal cleaning consists of the physical separation of the combustible organic matter in coal from the noncombustible mineral matter. Most coal undergoes this process before firing. A variety of methods exist for increased removal of sulfur and other elements. Coal cleaning will most likely be used in conjunction with other SO_2 compliance/reduction options, since sulfur removal rates are not high (relative to fuel blending/switching and scrubber options).

2.2.2 Flue Gas Treatment

Flue gas desulfurization (FGD), also known as scrubbing, removes SO_2 and other pollutants from the post-combustion flue gas. The four general flue gas cleanup categories are (1) wet limestone FGD, (2) wet regenerable FGD, (3) spray dryer FGD and (4) sorbent injection.

Wet limestone injection processes are capable of removing 70-95% of the SO_2 in flue gas. Higher levels of removal are also possible with use of adipic acids or other sorbent additives. The typical system uses a calcium-based sorbent (lime or limestone), possibly combined with another catalyst to remove SO_2. The sorbent acts as a catalyst, connecting to sulfur elements and removing the sulfur from the flue gas. Retrofitting a scrubber to an existing unit can be costly, and fitting the equipment into available space can be a major difficulty. In the past, additional FGD modules have been required because of incidences of unplanned outages of the FGD system. However, because of increased scrubber reliability, the current practice is to avoid the cost of spare modules. Operation costs of wet limestone FGD are also high, especially as efficiency approaches its limit. Parasitic electrical usage of new FGD units can be as much as 1.5% of the total amount generated. In addition, the use of limestone injection increases solid waste generation. However, processes have been developed to produce commercial-grade gypsum from the wastes generated by some FGD technologies.

Similar to the wet lime and limestone processes, wet regenerable FGD processes use a wet scrubbing methodology and have SO_2 removal rates comparable to those of wet limestone FGD processes. However, the wet regenerable processes are designed to recover sulfur products, such as sulfuric acid or elemental sulfur, and generate other useful by-products, such as commercial-grade gypsum. In addition, these processes result in a minimal discharge of wastewater. Capital costs of wet regenerable processes are higher than those of wet limestone processes because of the additional costs of the sulfur recovery equipment. However, the increased operating costs can be offset by the value of the recovered products. Ease of retrofit is similar to that of retrofitting a nonregenerable, wet limestone FGD system. The operation of the regenerable process diverts some generating capacity from use as salable electricity. Plant space requirements for regenerable technologies exceed the requirements of nonregenerable technologies; however, virtually no space is required for waste disposal.

Spray dryer scrubbing employs a wet scrubbing medium to remove the SO_2 from the flue gas and hot gases to dry the scrubbed mixture by evaporating the entrained moisture. The dried mixture requires subsequent treatment for particulate removal. This treatment is usually provided by a baghouse or electrostatic precipitator. Capital costs of such systems are often lower than the costs of a wet FGD system. However, when retrofitting with a spray dryer, the additional particulate matter present in the flue gas must be taken into consideration. Spray dryers typically use more expensive lime or other reagents for scrubbing. In general, the process becomes uneconomical when the coal contains more than 3% sulfur (Makansi 1991). However, a spray dryer is simpler to operate, and the disposal requirements for by-product waste are much less than for wet FGD. The SO_2 removal efficiency of spray dryer scrubbing ranges from 70 to 90%.

Application of sorbent injection methods is generally considered to be a retrofit option rather than a new source control strategy. A good deal of installation flexibility exists — injection can occur at several points, including the furnace, the convective pass area, or the ductwork. However, the relatively low capture efficiency (40-70%) has so far relegated the application of this technology to plants that are nearing retirement, are small or used at low capacity, do not have a high SO_2 control requirement, or are near an abundant source of reagent. Recent research on the use of sodium-based reagents (instead of the more traditional calcium-based ones) suggests that SO_2 removal efficiencies up to 90% may be possible. Capital costs are relatively low, but operating costs can be quite high. One reason for high operating costs is that the dry injection process lacks a gas-liquid-solid mass transfer interface and, thus, requires a higher volume of sorbent to achieve the same level of SO_2 removal as wet systems (Farber 1992).

2.2.3 Boiler Repowering

Boiler repowering entails replacing the furnace of an existing boiler with a new furnace incorporating one of the various modern technologies designed to minimize emissions of air pollutants and increase combustion efficiency. Options include advanced pulverized coal with an improved FGD system (APC/FGD), several varieties of fluidized bed combustion (FBC) boilers, and integrated coal gasification with combined cycle (IGCC). All of these options are either commercially available now or will be by the end of the decade. Hence, they all should be available for Phase II compliance applications.

A FBC furnace operates much like a scrubber system in that a sorbent is used to collect SO_2, but the collection occurs during combustion. The IGCC technology converts coal to gas, and the gas is burned in a turbine. The addition of a gas turbine to the stream turbine has the effect of increasing overall plant capacity. IGCC and some FBC applications also reuse waste heat to generate electricity, improving unit efficiency. Removal of SO_2 is estimated to range from 90% for atmospheric fluidized bed combustion applications to 99%+

for IGCC applications. In general, the cost of the first generation of these technologies is expected to be comparable to, or slightly greater than, the cost of existing pulverized coal units retrofitted with a FGD system (South et al. 1990). However, the cost of these applications is expected to decline as more units are built (DOE 1991).

2.2.4 Altered Generation Dispatch

Altered generation dispatch refers to a variety of operational activities (including demand-side management, reduced utilization, altered dispatch, power purchases, and altered dispatch/reduced utilization due to new unit additions) designed to result in overall reduction of SO_2 emissions. Electric utility system operators use economic dispatching to serve customer loads. Before implementation of the CAAA of 1990, dispatch order was based on the marginal cost of electricity from each unit. Under this approach, a utility would dispatch units with low marginal costs first, using a greater level of these units' available capacity. As electricity demand grew, additional units would be dispatched in the order of their marginal generating costs. The concepts of a baseload unit (a unit that runs continuously), a cycling/shoulder unit (a unit that comes on-line or increases generation as electricity demand rises), and a peaking unit (a unit that runs for brief periods and has the highest marginal costs) originate from this process.

The amount of SO_2 emissions is positively related to generation — an increase in generation results in increased emissions of SO_2. Therefore, SO_2 allowances are a part of the marginal energy costs for an electric utility. As such, utilization of units may be altered by the inclusion of SO_2 allowances in the economic dispatch plan. Depending on the relative marginal costs and SO_2 emissions of a system's units, utilization and dispatch order may vary.

Demand-side management activities have the potential to alter the shape of the load curve, reducing or increasing energy use at points along the load curve, or reduce the growth in energy demand. Demand-side management programs that reduce baseload energy demand or slow energy demand growth will be most effective in reducing system SO_2 emissions, but only if they reduce the emissions from existing units and not just displace new advanced generating technologies. In contrast, demand-side management programs that shift demand from peak to nonpeak periods may actually increase SO_2 emissions.

Off-system power purchases may also be a cost-effective means of achieving system compliance. If another system has a block of electricity with a lower marginal cost of delivered fuel (including allowance costs) than the next unit in a system's dispatch order, the cost-effective strategy would be to purchase the off-system energy. At present, intersystem coordination of power transfers is extensive and is expected to increase as a result of reforms (e.g., possible open access transmission) in the National Energy Policy Act of 1992 (Public Law 102-486).

The addition of new baseload units to a system will alter existing dispatch order, system SO_2 emissions, and utilization of other units. If a new unit replaces an existing unit,

SO_2 emissions decrease by a significant amount. If a unit is added to meet increased energy demand, system SO_2 emissions may still decrease through a change in the dispatch loading order, but the overall effect could be negligible.

2.2.5 Allowance Market

The fifth means of compliance is the purchase or transfer of allowances. In this case, a utility could choose to over-control at certain units and use the freed allowances to "cover" the emissions from other units. A utility may also purchase allowances to cover annual emissions.

Allowance transfers/purchases and altered dispatch will likely be used extensively as cost-effective means of achieving compliance with SO_2 emissions requirements. These strategies allow a utility system to preserve compliance flexibility and retain access to the entire array of SO_2 compliance options.

2.3 COMPLIANCE PLANNING ISSUES

2.3.1 Compliance Planning Objectives

The aim of power system planners is to minimize the costs of generation, transmission, and distribution without sacrificing reliability. With the addition of SO_2 allowances to the compliance planning process, utilities will seek to minimize the delivered cost of fuel and the cost of SO_2 control (Weinstein 1991).

Economic theory holds that under a system of marketable allowances, all firms affected by the program will seek to reduce (or maintain) their current emissions such that the marginal cost of control is equal (across firms) to the allowance price (Tietenberg 1985), or

$$MCC_1 = MCC_2 = \ldots = MCC_n = P_a, \tag{1}$$

where

MCC_i = Marginal cost of control for the ith firm, i = 1, ..., n, and

P_a = Market allowance price.

In a similar manner, the affected units within each firm will equate the marginal costs of emissions controls with the allowance price. Another way of portraying the cost minimizing actions taken by an affected utility is with the use of a compliance options supply curve. A stylized example of such a curve is illustrated in Figure 1. Given a portfolio of potential compliance options, the firm will employ additional control options up to the point

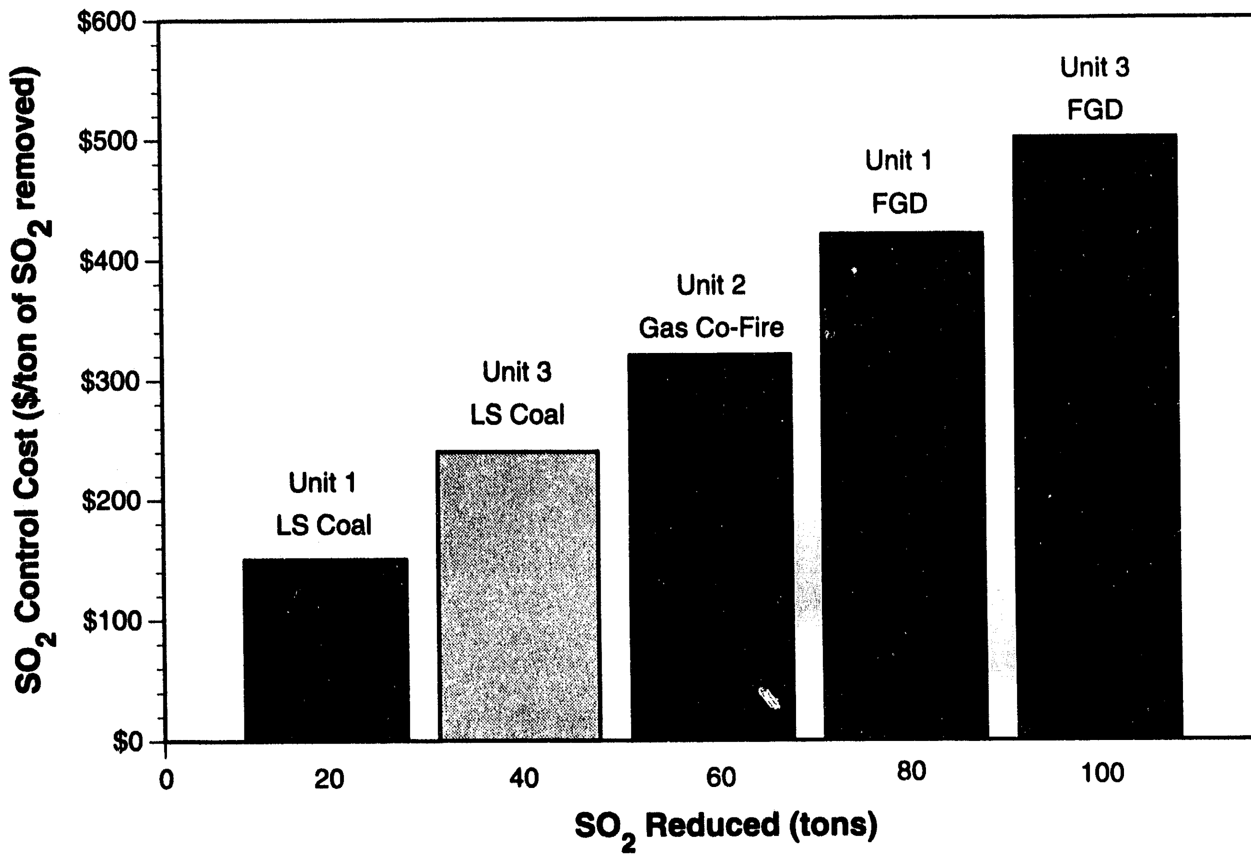

FIGURE 1 Compliance Option Supply Curve

at which the allowance price is less than the cost of the next control option. If allocated allowances are less than current emissions, the utility would then seek to purchase the needed allowances.

2.3.2 Integrated Resource Planning and Title IV Compliance Planning

The compliance planning process and the integrated resource planning (IRP) process are strikingly similar. In fact, many of the affected Phase I utilities are incorporating their compliance plans into their IRP process. For utility compliance planning, only a slight alteration in the traditional IRP framework is required, as illustrated in Figure 2. Instead of examining the universe of power generation options, the planner examines the universe of SO_2 compliance options (which may include many alternative power generation options). The screening criteria for the compliance options are essentially similar to those in the IRP setting. The difference between the two sets of criteria lies in the associated environmental requirements.

Of special note in the screening criteria is the examination of various categories of risk associated with each option. Technology risks refer to factors such as a utility's

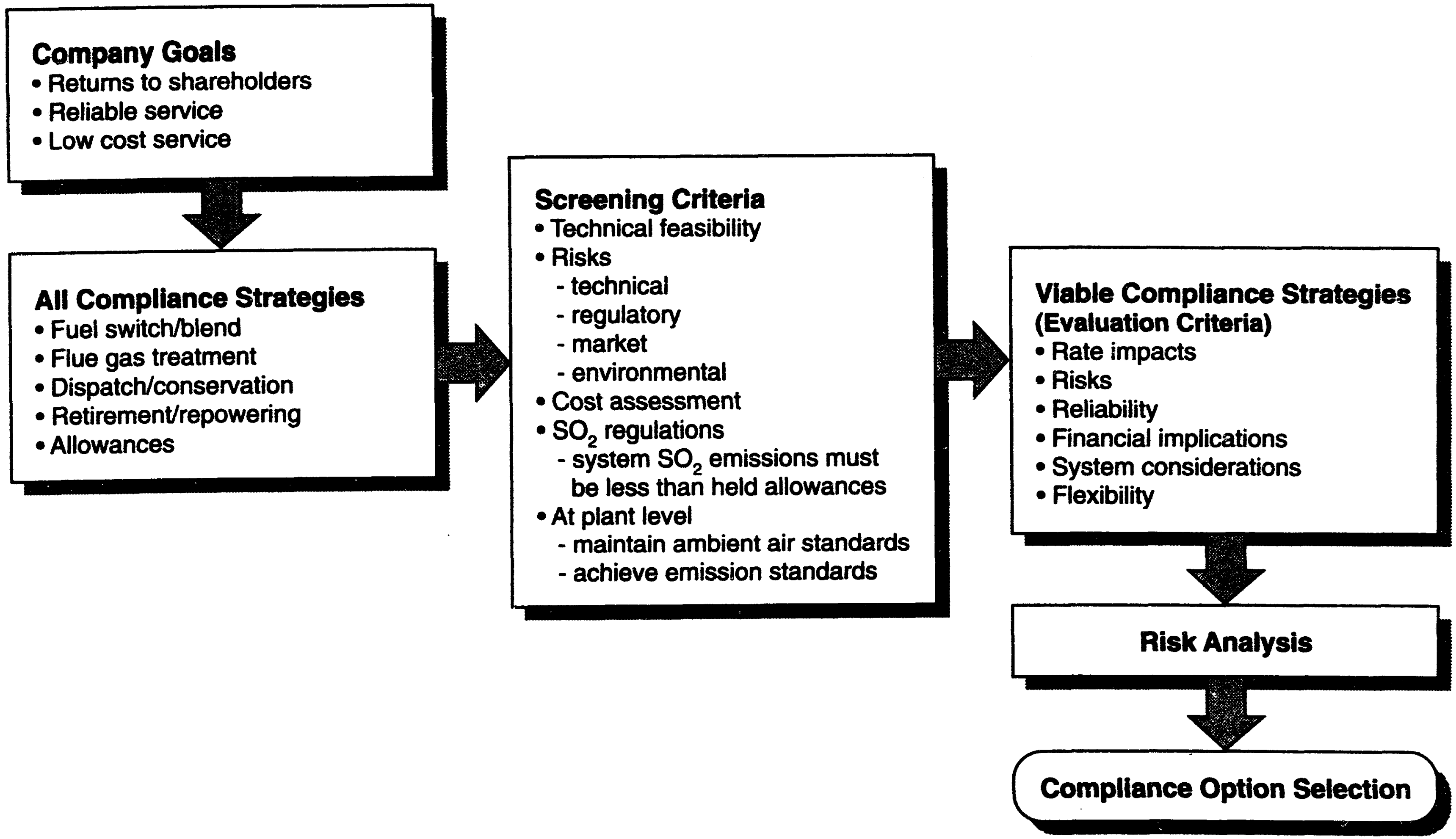

FIGURE 2 SO_2 Compliance Planning

experience with a technology, required lead times, potential for retrofit and, to a certain extent, the potential for altering the option at a later date. Regulatory risks include factors that may prevent full recovery of the compliance option costs. In addition, regulatory risk can include socioeconomic impacts of the policy on customers within the utility's service territory. Environmental risks reflect concerns regarding compliance after the implementation of the option. These concerns include adaptability to future regulations, permitting issues, and ability to meet current requirements. Market risks address cost and financial-related impacts associated with compliance decisions. All risks and their subcomponents are weighted on the basis of their relative importance to the utility. The assessment at this point is usually qualitative.

After screening, a set of viable compliance strategies emerges. For the IRP process, a set of viable supply-side and demand-side options would be indicated. At this point, the viable strategies are evaluated on the basis of rate impacts, flexibility, reliability, risk, financial integrity, and system considerations. Figure 3 illustrates the evaluation criteria and subcriteria used in the process. Finally, the chosen strategies undergo a quantitative risk analysis that is typically based on various assumptions about load growth, fuel price changes, and other factors. For the compliance planner, another factor could, for example, be possible imposition of additional environmental regulations. The options that provide the most robust result in terms of expected net benefits will be selected.

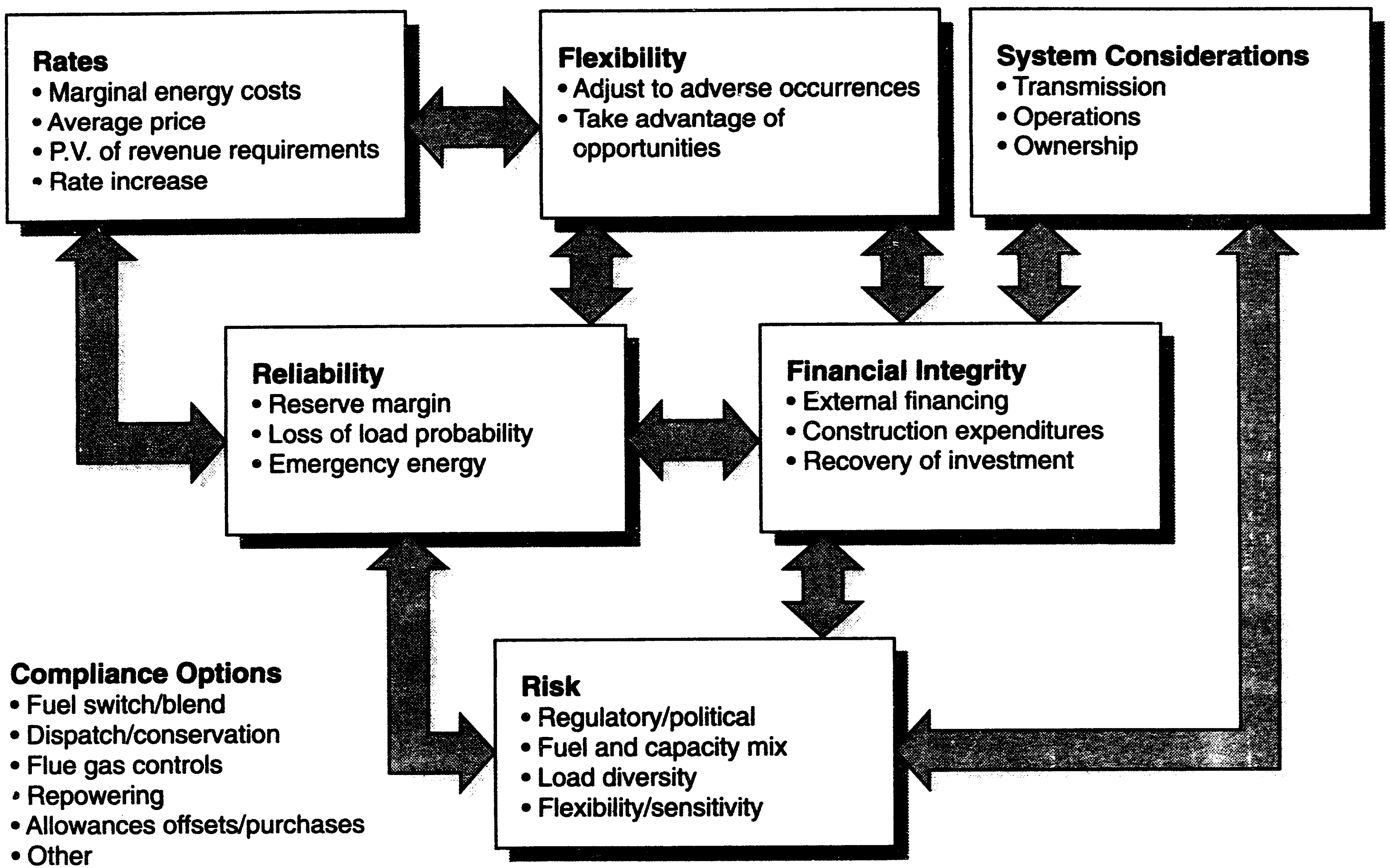

FIGURE 3 Set of Evaluation Criteria

3 SUMMARY OF THE UTILITY COMPLIANCE AND STATE REGULATORY DATABASES

3.1 UTILITY COMPLIANCE DATABASE

3.1.1 Introduction

The Utility Compliance Database developed by Argonne National Laboratory for this study provides a broad range of descriptive information on the 263 units affected by Phase I, as well as their compliance plans. The database is intended to serve as a readily accessible source of Title IV compliance data for the U.S. Department of Energy (DOE) and the National Acid Precipitation Assessment Program (NAPAP). The utility database is contained in a .DBF format and could serve as an input to energy modelling with some modifications. Information was gathered through the trade literature, contacts with state PUCs, other state agencies, utilities, and regional EPA offices. Appendix A contains a guide to the 17 codes used to categorize this information. Because of the relative scarcity of Phase II compliance information, the database currently focuses primarily on Phase I units. The usefulness of the database will be enhanced as additional information, such as finalized Phase I plans and Phase II decisions, becomes available.

All utilities affected by Phase I were required to submit their Section 408 acid rain permit applications for Phase I to regional EPA offices by February 15, 1993. Although permit applications were submitted, some utilities are continuing to adjust their compliance strategies. Consequently, the database should be regarded as providing a "snapshot" of indicated compliance strategies at a moment in time. Several utilities plan to rely on more than one action to achieve compliance, (e.g., designating a substitution unit and switching to lower-sulfur coal). In such cases, all aspects of a unit's compliance plan are described in the database.

3.1.2 Compliance Activities of Phase I Units

This section summarizes the information in the utility database regarding compliance activities of Phase I units. Tables 1 and 2 present the compliance options selected for the 263 affected units. The tables summarize the number of units exercising each option, a distribution of unit capacities, and the ages of units choosing a particular option. The Argonne Power Plant Inventory (APPI) Database provided the unit capacity and age data for the Utility Compliance Database; the capacity reflects available capacity at the end of 1991. In the tables, the distinction between coal blending and coal switching is not firm. In many cases, utilities are not electing for wholesale alternation of current coals or strictly choosing one low-sulfur coal to burn. In reality, units are mixing coal grades to achieve compliance goals. Coal blending has been indicated when a utility's compliance plan has

TABLE 1 Summary of Compliance Options for Phase I Units[a]

Compliance Option[b]	Number of Units	Capacity (MW)
Coal blend (1.1)	20	3,871
Coal switch (1.2)	102	32,055
Natural Gas (1.3)	2	441
Wet FGD (2.1)	26	13,189
Boiler repower (3.0)	1	85
Substituting/compensating unit (4.1)	89	27,964
Sulfur-free reduced utilization (4.6)	56	18,348
Allowance purchase (5.1)	8	3,521
Allowance offsets (5.2)	32	10,267
Existing compliance (6.1)	28	8,933
Unidentified/no plan indicated (0.0/6.2)	12	2,803

[a] Many units have selected multiple compliance options (e.g., wet FGD and substitution). Therefore, the sums of the "Number of Units" and "Capacity" columns would exceed the total number and capacity of Phase I units.

[b] The numerical codes following the compliance option are the codes used in the Utility Compliance Database (see Appendix A).

expressed the continued use of current coal blended with a lower-sulfur coal. Another issue of note is the use of natural gas co-firing. Although several units have indicated co-firing as a possibility, few were identified as proceeding with this action at present.

Conservation as an SO_2 reduction strategy is noticeably absent from the tables. Conservation activities will tend to result in emission reductions from units across an entire utility system. Many utilities have established conservation measures and have planned further conservation actions. In cases where utilities indicated conservation as a part of their SO_2 complain strategy, that information is included in the database, but no conservation activities are indicated in the tables because that was not a primary compliance strategy.

3.1.2.1 Unit Compliance Choice

The primary compliance strategy for Phase I units is fuel switching to eastern and western coals with lower sulfur content. Of the 263 Phase I units, 102 plan to employ this option to achieve the SO_2 reductions necessary for compliance. Eighty-four of these units are less than 350 MW, and 118 are less than 40 years of age. Related to fuel switching is the use of fuel blending or "trimming." Blending refers to the mixing of the current coal used with

TABLE 2 Capacity Frequency and Age Distributions of Phase I Units

Category	All Units	Compliance Strategy: Wet FGD	Coal Blend/ Fuel Switch	Allowance Purchase/ Offsets	Existing Compliance	Substitution/ Compensating
Capacity Frequency (MW)						
<101	22	2	8	6	0	16
101-250	127	9	65	16	10	57
251-350	32	2	13	1	8	21
351-500	24	1	13	3	5	18
501-750	42	6	18	11	5	23
751-1,000	9	2	5	2	0	3
>1,000	5	4	0	1	0	5
Age Distribution[a]						
<1949	11	1	5	1	0	8
1950-1956	59	1	35	7	1	26
1957-1961	52	1	20	10	10	33
1962-1966	32	5	10	6	3	13
1967-1974	97	17	44	16	14	59
1975-1980	8	1	6	0	0	4
1981-1990	2	0	2	0	0	0
>1990	0	0	0	0	0	0
Number of Units Identified[b,c]	263	26	122	40	28	145

[a] Period in which unit was brought on line.

[b] Because a number of units are using multiple strategies to achieve compliance, the sum of the total number of units listed for the various strategies exceeds the total number of Phase I units.

[c] Five units were not identified, and six units have retired or will retire before 1995. The retired units were brought on line between 1949 and 1955. Two units have elected natural gas co-firing, and seven units have indicated no strategy.

a lower sulfur variety. Twenty units have specifically identified plans for blending. There may be overlap in the units defined as fuel switching and fuel blending in cases where units indicating fuel switching continue to use at least some proportion of the coal currently used while switching to low-sulfur coals.

Installation of wet limestone FGD systems appears to be the second most frequently chosen technical compliance strategy for Phase I compliance. Twenty-six units will be constructing wet limestone FGD controls in response to Phase I limits. One noted advantage of FGD is its removal of additional regulated and potentially regulated pollutants. Although NO_x is the only other pollutant regulated under Title IV, concerns about other pollutants slated for control under the CAAA, such as air toxics, may have contributed to the selection of FGD by some utilities. It is also likely that state construction-work-in-progress (CWIP) provisions and in-state coal use incentives and mandates carried considerable weight in utilities' decisions to pursue this option (see Section 4). This option is being used most in the midwestern and eastern states that produce coal with high sulfur content.

The units using wet FGD are found in Indiana (seven units), Kentucky (four units), West Virginia (four units), Ohio (two units), Pennsylvania (two units), New York (two units), New Jersey (two units), Tennessee (two units), and Georgia (one unit). As expected, units in states with large high-sulfur coal reserves tend to rely more heavily on scrubbing than do units in other states. Those utility systems with units installing wet limestone FGD have tended to rely on allowances generated by the scrubbing units to cover SO_2 emissions. Factors such as low transportation costs for fuel and state regulations favoring the continued use of in-state coal have encouraged greater use of wet limestone FGD in states with large reserves of high-sulfur coal.

A total of 145 units have indicated that they are selecting substitution or compensating units for compliance. Of the 145 units, 56 are reducing utilization without any associated increases in SO_2 emissions from other units. A Phase I unit can have sulfur-free reduced utilization if (1) the reduced generation is met by conservation resources; (2) nuclear, renewable, or hydroelectric generation increases; or (3) if unit fuel conversion efficiency increases, resulting in less SO_2 emitted per kilowatt-hour. Almost every utility system has indicated that at least one unit has designated a substitution or compensating unit.

Six units (four in Wisconsin, one in Indiana, and one in Ohio) will rely on retiring-unit offsets to achieve Phase I compliance. None of these states has regulations in place that account for the retirements. All six retired units are over 40 years old. Five have a capacity of about 100 MW each, and one has a capacity of about 400 MW.

Thirty-two Phase I units will achieve compliance by obtaining allowances from system offsets. Eight others will rely on allowance purchases as their primary means of achieving compliance with Phase I. These 40 units tend to have a larger average capacity (461 MW) than Phase I units as a whole (317 MW) and were allocated a larger average number of allowances (29,206) than the overall Phase I average (21,043).

Baseline emissions for Title IV, on which Phase I and II limits are based, represent unit-specific averages for the years 1985-1987. Twenty-eight units have implemented controls since 1987, bringing these units into early compliance. Many of these units are in Michigan, Missouri, New York, and Wisconsin, and many of them have also designated substitution units. In the cases of New York, Wisconsin, and Missouri, these reduced emissions can be attributed to state SO_2 control programs that preceded enactment of the CAAA. In most cases, units that reduced their emissions after the 1985-1987 baseline period employed coal switching to coals with lower sulfur content as the means of achieving such reductions.

Several caveats are in order when control strategies such as allowance offsets, demand-side management (DSM), and altered utilization are indicated as the means of achieving compliance. In many cases, the compliance plans indicate purely technology "fixes" rather than system approaches to compliance. Altering the marginal compliance costs and SO_2 emissions change the marginal costs of electricity production. This change, in turn, leads to changes in the dispatch order and utilization. Dispatch and utilization changes are expected in most, if not all systems.

Both DSM and on-system allowance offsets are probably under-represented. Today, most utilities required to submit IRP plans must engage in DSM. Although few utilities have identified DSM as a unit-based compliance strategy, from a system perspective utilities potentially have the ability to reduce SO_2 emissions through this strategy. At present, we are uncertain of the number of units with sulfur-free utilization that are relying on DSM. The use of allowance offsets will become more apparent as the market for allowances develops and as the other compliance options are installed.

3.1.2.2 Geographic Distribution of Compliance Strategies

This section examines Phase I units by power pool and North American Electric Reliability Council (NERC) region. The NERC is an administrative body formed to coordinate and promote electricity reliability. Since 1968, the electric utility industry has moved toward greater integration of capacity planning, transmission, and distribution. Four large power interconnects currently exist in North America — the Eastern Interconnect, the Western Interconnect, the Texas Interconnect, and the Quebec Interconnect. Within the interconnects, power p ·ls operate with varying degrees of coordination. Theoretically, these systems operate on the basis of least-cost dispatch, whereby where units with the lowest marginal energy costs are dispatched first, followed in turn by higher-cost units.

The units affected in Phase I are located in several different NERC regions and power pools (Figure 4 and Table 3). The NERC regions affected by Title IV include the Mid-America Interconnected Network (MAIN), the Eastern Central Area Reliability Agreement (ECAR) and the Mid-Atlantic Area Council (MAAC), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), and the Southwest Power Pool (SPP). These regions contain 16 separate power pools affected by Phase I, including the American Electric Power System, the Allegheny Electric Power System, the Pennsylvania-New Jersey-Maryland (PJM) Interconnect, Tennessee Valley Authority (TVA), and several others.

The Mid-Continent Area Power Pool (No. 12) is a NERC region that operates as an integrated power pool and includes six Phase I units — five in Iowa and one in Minnesota. The dominant strategy is fuel switching to western low-sulfur coals. To comply with Minnesota's SO_2 control law, High Bridge Unit 6 (a Phase I unit) has been using low-sulfur western coal since 1986. The five Iowa units are using a combination of fuel switching to low-sulfur western coal and fuel blending.

The MAIN NERC region contains three affected power pools — the Wisconsin-Upper Michigan Power Pool (No. 11), the Commonwealth Edison Power Pool (No. 8), and the Southern Illinois-Eastern Missouri Power Pool (Nos. 9 and No. 10). Thirty-six Phase I units are located in the region. No scrubbing is occurring in the MAIN region. The Wisconsin-Upper Michigan Subregion Power Pool (No. 11) contains 13 Phase I units. The four North

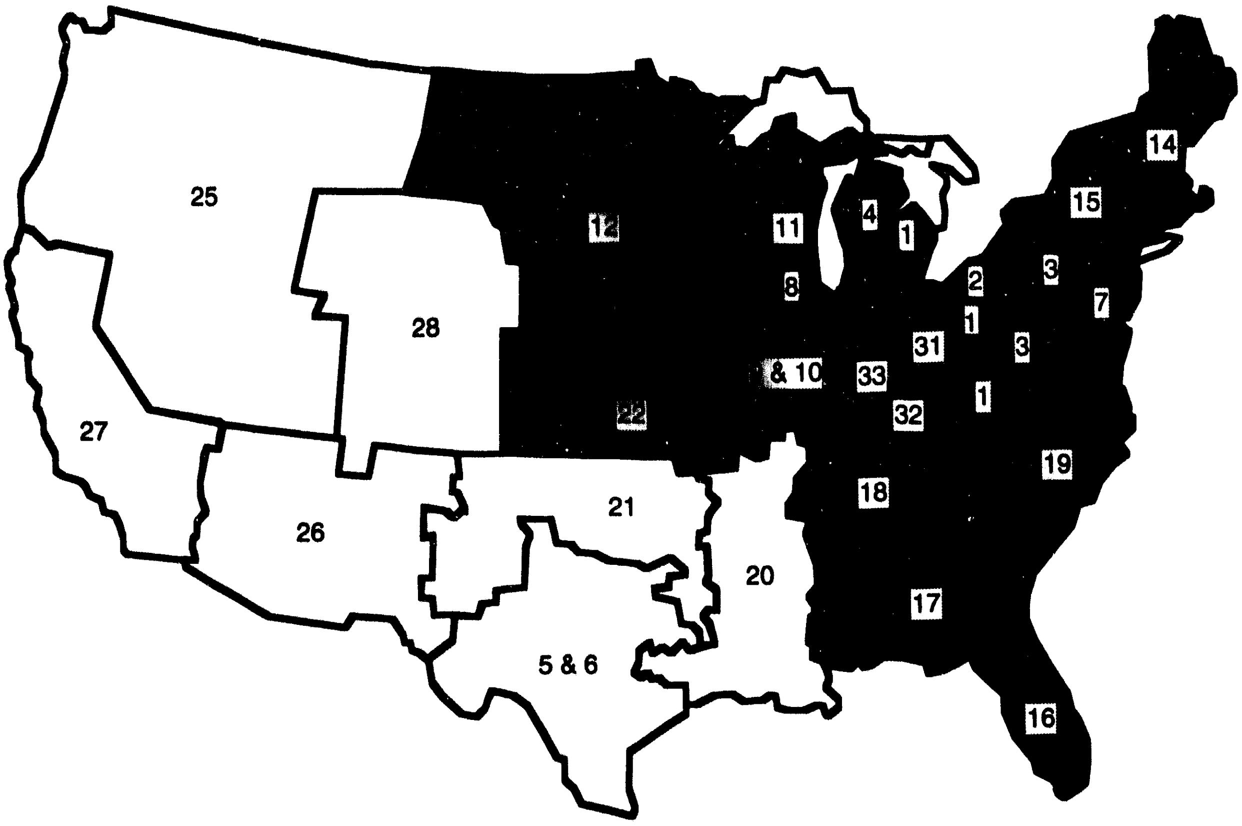

FIGURE 4 Approximate Geographical Boundaries of Power Pools

Oak Creek units (included among the 13) were retired in 1989.[22] The dominant compliance strategy among the other units is to switch to low-sulfur coal. Wisconsin's 1986 SO_2 reduction law requires the Wisconsin units to maintain an average of 1.2 lb SO_2/MMBtu as of January 1, 1993. In the Commonwealth Edison Power Pool (No. 8), an Illinois state law had presumably required scrubbing at the two 554-MW Kincaid units, but the units will be firing low-sulfur Illinois coal. In the Southern Illinois-Eastern Missouri Power Pool (Nos. 9 and 10), Illinois Power's three Baldwin units are electing to purchase allowances and continue using Illinois high-sulfur coal. Other compliance options selected by Illinois units include fuel switching (three units) and on-system allowance offsets (three units). Joppa Units 1-6 have selected blending of Powder River Basin coal with local high-sulfur coal to achieve compliance. All six units in the East Missouri Subregion Power Pool (No. 10) began the process of switching to low-sulfur western coals in 1988; this process is continuing.

[22] North Oak Creek Units 2, 3, and 4 are retired and have designated sulfur-free replacement capacity. Unit 1 at North Oak Creek is retired and has designated a compensating unit.

TABLE 3 Power Pool Compositions

Power Pool Number	NERC Region[a]	Participants
1	ECAR	American Electric Power System, Buckeye Power Inc., Ohio Valley Electric Corp., Richland Power and Light
2	ECAR	Central Area Coordination Group, Byron Municipal Light and Water, Cleveland Division of Light and Power
3	ECAR	Allegheny Power System
4	ECAR	Michigan Electric Coordinated Systems, Michigan Municipal Cooperative Pool, Detroit Public Lighting Dept., Edison Sault Electric Co., Lansing Board of Water and Light, Michigan Public Power Agency
5 & 6[b]	ERCOT	Texas Interconnected Systems, Associate Members of ERCOT
7	MAAC	Pennsylvania-New Jersey-Maryland Interconnection, Associate Members of MAAC
8	MAIN	Commonwealth Edison Co.
9 & 10[c]	MAIN	Illinois-Missouri Group (South-Central Illinois Subregion and East Missouri Subregion of MAIN)
11	MAIN	Wisconsin-Upper Michigan Subregion of MAIN
12	MAPP	Mid-Continent Area Power Pool
13	MAPP	Nonmember utilities in the MAPP region
14	NPCC	New England Power Pool
15	NPCC	New York Power Pool
16	SERC	Florida Subregion of SERC
17	SERC	Southern Subregion of SERC
18	SERC	Tennessee Valley Authority
19	SERC	Virginia-Carolinas Subregion of SERC
20	SPP	Group A (Western Arkansas-Louisiana-Mississippi area of SPP)
21	SPP	Group B (Oklahoma area of SPP)
22	SPP	Group C (Western Missouri-Kansas area of SERC)
23 & 24	–	No longer used. Originally covered two additional groups in SPP until that region was characterized by three groups.

TABLE 3 (Cont.)

Power Pool Number	NERC Region[a]	Participants
25	WSCC	Northwest Power area of WSCC
26	WSCC	Arizona-New Mexico area of WSCC
27	WSCC	California-Nevada area of WSCC
28	WSCC	Rocky Mountain area of WSCC
29	–	Alaska Systems Coordinating Council (affiliate NERC member)
30	–	Hawaii
31	ECAR	Cincinnati Gas and Electric Co., Dayton Power and Light Co., Hamilton Dept. of Public Utilities Electric Division
32	ECAR	Kentucky Utilities Group, Big Rivers Electric Corp., Eastern Kentucky Power Cooperative, Inc., Henderson Municipal Power and Light, Louisville Gas and Electric Co., Owensboro Municipal Utilities
33	ECAR	Hoosier Energy Rural Electric Cooperative Inc., Indianapolis Power and Light Co., Northern Public Service Co., Public Service Co. of Indiana Inc., Southern Indiana Gas and Electric Co., Wabash Valley Power Assoc.

[a] The NERC regions are East Central Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Northeast Power Coordinating Council (NPCC), Southeastern Reliability Council (SERC), Southwest Power Pool (SPP), and the Western Systems Coordinating Council (WSCC).

[b] Although there are two components of the ERCOT region (basically the Texas Utilities Group and the Central and Southwest Group), they are treated as a single power pool in this study because the Texas Interconnected System provides a high level of coordination in planning and operation.

[c] The two components of the Illinois-Missouri Group are treated as a single pool because of their high level of coordination in planning and operation.

In the Southwest Power Pool (SPP), the Northern Subregion Power Pool (No. 22) contains 11 units — 10 in Missouri and 1 in Kansas. All of these units will switch, or have previously switched, to low-sulfur western coal. The Kansas City Quandro 2 unit has been blending low-sulfur Powder River Basin coal and Illinois Basin coal since 1989. Four of the units in Missouri switched to low-sulfur western coal before 1991.

The Southeastern Reliability Council (SERC) region, which contains 61 Phase I units, consists of the Southern Power Pool (No. 17), the TVA Power Pool (No. 18), the Florida Power Pool (No. 16), and the Virginia-Carolinas (VACAR) Power Pool (No. 19). Except for the TVA units in Alabama and Tennessee, the predominant compliance strategy in the SERC region is fuel switching away from the traditionally preferred Illinois Basin coal.

Of the 28 affected units owned by the Southern Company (in the Southern Power Pool), 26 are switching to low-sulfur coal. The TVA's 26 units operating in the SERC region rely on a mix of fuel switching, reduced utilization, and scrubbing the large Cumberland units. Fourteen units will rely on sulfur-free reduced utilization. Five units are blending with low-sulfur fuel. Some of the units slated for altered utilization have test burned low-sulfur coals, suggesting that they are contemplating fuel switching at some future date.

In the Florida Power Pool (No. 16), Tampa Electric's Big Bend Units 1, 2 and 3 are fuel switching to low-sulfur coal and have designated substitution units. In VACAR, the three affected units are Virginia Electric's Mt. Storm Units 1, 2, and 3 in West Virginia. Mt. Storm 3 will use a wet FGD system, and the other units will rely on allowance offsets.

ECAR is one of the NERC regions most affected by Title IV, with 90% of the region's generating capacity over the next 10 years projected to be from coal-fired units (NERC 1992). ECAR, comprising seven power pools located in Pennsylvania, West Virginia, Ohio, Michigan, Indiana, and Kentucky, contains 110 Phase I units.

Within ECAR, the American Electric Power Pool (No. 1), in which other smaller utilities also participate, will meet compliance goals through a combination of fuel switching, allowance offsets, and FGD (Gavin Units 1 and 2). The power pool contains 21 units. Ten units have indicated that a combination of fuel switching and substitution will be used. Seasonal or co-firing of natural gas will be used for four of the units.

ECAR Power Pool No. 2 includes units in northern Ohio and western Pennsylvania. None of the 21 affected units in this power pool will rely on wet FGD to achieve compliance. Seventeen units are fuel switching to low- or medium-sulfur coal. One unit is being considered for retirement or conversion to natural gas. Duquense's Cheswick Unit 1 is taking no compliance action because existing controls bring emissions below the number of equivalent allocated allowances. Altered dispatch and allowance purchases are given as the intended compliance strategies for many units. Ohio Edison has indicated that it is considering purchasing allowances to achieve compliance at its three fuel-switching units.

In the Allegheny Power System (ECAR Power Pool No. 3), 3 of the 11 Phase I units are installing wet FGD. These three units represent about 1,900 MW (42%) of the 4,500 MW of capacity in this power pool affected by Phase I. The remaining units are using allowances from system offsets. It appears likely that these units will also alter generation levels to further reduce SO_2 emissions.

Michigan is the only state in ECAR that does not contain large high-sulfur coal reserves. The two affected units in Michigan — Consumers Power Campbell Units 1 and 2 — operate in ECAR's Region 4 power pool. These units have already switched to low-sulfur coals to meet state requirements.

ECAR Power Pool No. 31 contains four Phase I units (Miami Fort Units 5-1, 5-2, 6, and 7). Fuel switching to eastern low-sulfur coal is planned for these units, with Unit 6 also reducing utilization. In addition, Cincinnati Gas and Electric (owner of these units) plans to implement aggressive demand-side management programs to aid in the reduction of SO_2 emissions.

ECAR Power Pool No. 32 covers most of Kentucky. Four of the 15 units plan to use FGD. These four units represent 1,100 MW of the pool's 2,800 MW of affected capacity. Three units in the pool are switching to medium-sulfur coal. Five units are relying, at least partially, on allowance offsets generated by the scrubbing units. Three units are designated substitution units. Because of the proportion of capacity being scrubbed, the allowance offsets available within system should be sufficiently large to accommodate this strategy.

ECAR Power Pool No. 33 covers most of Indiana. Seven of the 29 units in the pool, representing 2,100 MW of capacity, are planning to use wet FGD to achieve compliance. Seventeen units have indicated that they are planning to switch to low-sulfur Indiana coal or blend Indiana coal with low-sulfur coal to reduce total sulfur content. Wabash River Unit 1 is repowering with an IGCC. Three units are relying on allowance offsets. Ten of PSI Energy Inc.'s 15 affected units will reduce utilization and compensate the reduced utilization with SO_2-free generation and conservation options. Indianapolis Power and Light has identified all seven of their Phase I units as selecting substitution units.

The MAAC region contains 23 affected Phase I units. The PJM Interconnect (Power Pool No. 7) is the only power pool in the region. The PJM Interconnect contains many of the units applying wet FGD. Approximately 2,000 MW of the power pool's capacity (England Units 1 and 2 and Conemaugh Units 1 and 2), is accounted for by these units. Six units are switching to low-sulfur eastern coal. Chalk Point 2 will co-fire natural gas or use seasonal co-firing to reduce SO_2. About 1,800 MW of capacity will rely on allowance offsets and purchases for compliance. NERC has indicated that the extensive level of scrubbing combined with the need for many of these units to install stricter NO_x controls due to Title I requirements may result in increased costs and reliability difficulties for the PJM Interconnect as a whole.

The NPCC contains the Northeast Power Pool (NEPOOL); the New York Power Pool (NYPP); and the Canadian provinces of Ontario, Quebec, New Brunswick, Nova Scotia, and Prince Edward Island. Twelve units in NPCC are affected by Phase I.

In NEPOOL (Power Pool No. 14), New Hampshire Public Service Company's Merrimack Units 1 and 2 have been indicated as possible retiring units by 2000. The NYPP (No. 15) contains 10 units affected by Phase I. New York already has a SO_2 control law that will reduce emissions by 1994. New York and Wisconsin (which also has an SO_2 control law) are expected to be net sellers of allowances in Phases I and II. New York State Gas & Electric's Miliken Units 1 and 2 are expected to use wet FGD. Niagara Mohawk's Dunkirk Units 3 and 4 will rely on reduced utilization and substitution of energy from other plants or conservation. LILCO's Northport Units 1, 2, and 3 and Port Jefferson Units 3 and 4 have previously switched to low-sulfur oil as their primary fuel.

3.2 STATE REGULATORY DATABASE

The State Regulatory Database is a compilation of state-level legislative and regulatory actions that have been instituted in response to Title IV or that address the same issues as the federal acid rain program. Table 4 summarizes the information in the database.

Only two state legislative fuel/technology mandates have occurred. At least 10% of all coal used in coal-fired utility boilers in Oklahoma was required to come from in-state sources. This requirement was established before 1990. The state of Wyoming, a major producer of low-sulfur coal, challenged the Oklahoma requirement in 1992 on the grounds that it interfered with interstate commerce. The 10% in-state coal requirement was deemed unconstitutional by the Supreme Court in 1993 and was rejected.

The second legislative mandate came from Illinois. Essentially, the state's two largest coal-fired plants, Commonwealth Edison's Kincaid Units 1 and 2 and Illinois Power's Baldwin Units 1, 2, and 3 were required by a state act to install SO_2 control devices in response to Title IV. In exchange for the installation of a control device, the utilities would be granted fuel cost passthrough and subsidies. The general interpretation of the act was that these units would install scrubbers and continue to use Illinois coal. However, the plants are not installing any flue gas control, although they are continuing to use Illinois-mined coal.

Massachusetts, Minnesota, New York, Wisconsin, and Wyoming all have state SO_2 control laws and regulations. In the case of Massachusetts, Minnesota, and Wyoming, the regulations are directed at specific boilers. The New York and Wisconsin laws are wider-reaching, multiphase programs established before 1990 to reduce acidic precursors. Related to state regulation of acidic precursors is the protection of sensitive areas from acidic deposition. The Massachusetts and Wisconsin SO_2 control regulations address emissions near ecologically sensitive areas. In New York, several state agencies are examining the issue of restricting allowance trading to sources.

A general trend in the regulation of electric public utilities has been toward the use of integrated resource planning. Only 3 of the 23 states with Phase I units do not have integrated resource planning requirements. While Tennessee has no planning requirements, TVA does have a planning process that addresses supply and demand resources.

Connecticut, Florida, Iowa, Indiana, Ohio, and Pennsylvania have preapproval regulations. In the case of Connecticut, an allowance trade was preapproved by the state's PUC. In this case, the PUC also allocated the proceeds of sale to ratepayers and shareholders. The latter four state's preapproval programs allow their regulated utilities to submit Title IV compliance plans to the state PUC for review and approval.

TABLE 4 Summary of State Title IV Actions

State	Action Category Codes[a,b]															
	1.1	1.2	2.1	2.2	3.1	3.2	4.1	4.2	4.3	4.4	5.1	5.2	5.3	5.4	6.1	6.2
Alabama																
Connecticut								X								
District of Columbia							X									
Florida							X	X								
Georgia							X		X							
Iowa							X	X			X		X			
Illinois	X	X		X			X				X					
Indiana				X			X	X			X					
Kentucky							X				X					
Massachusetts					X	X	X									
Maryland							X									
Michigan							X									
Minnesota					X		X				X					
Missouri							X									
Mississippi											X					
New Hampshire							X									
New Jersey							X									
New York					X	X	X				X		X			
Ohio		X	X	X			X	X	X		X	X	X			
Oklahoma	X															
Pennsylvania			X				X	X			X		X			
Tennessee							X									
Virginia							X									
Wisconsin		X			X	X	X				X					
West Virginia				X												
Wyoming					X											

See next page for footnotes.

TABLE 4 (Cont.)

[a] Definitions of state action codes (see also Appendix B):

1. State Mandates
   - 1.1 Coal use requirement
   - 1.2 Technology requirement
2. State Incentives
   - 2.1 Coal use tax credit
   - 2.2 Technology subsidy
3. State Environmental Programs
   - 3.1 Preexisting acid rain/SO_2 law
   - 3.2 Sensitive area protection
4. Planning Issues
   - 4.1 IRP process
   - 4.2 Preapproval
   - 4.3 Prudency issue
   - 4.4 Risk/reward indicator
5. Rate Making
   - 5.1 Surcharge/rate recovery mechanism
   - 5.2 Incentive regulation
   - 5.3 Allowance valuation
   - 5.4 Bidding rules/allowance allocation
6. Regional/Interstate
   - 6.1 Multistate planning
   - 6.2 Coincident, multistate approval of options

[b] An "X" indicates that action has been instituted by the state indicated.

Georgia and Ohio have issued prudence rulings related to allowance trading. Georgia requires a utility to consider trading if the price of allowances is less than $200 per ton. If the utility fails to consider trading, the decision may be ruled not prudent. Ohio's prudence requirements for trading are more vague, requiring utilities to consider trading as a compliance option.

Several states have rate recovery mechanisms for pollution control projects. For the most part, these recovery mechanisms allow CWIP recovery for scrubbers. Kentucky and Mississippi have proposed that environmental surcharges be included in rates as utilities incur costs of complying with Title IV. However, these surcharges have not actually been implemented. PSI Energy has proposed a regulatory incentive program to recover the costs of its Gibson 4 scrubber. This program would be expanded to include all Title IV compliance costs. At present, the Indiana PUC has not approved this proposal.

Iowa, Ohio, Pennsylvania, and Wisconsin have all made rulings on the valuation and allocation of the revenue generated by allowances sales. Ohio and Wisconsin indicate that all benefits from allowance sales are to go to ratepayers. Iowa and Pennsylvania have indicated that shareholders may get some return on the sale of allowance. The New York Public Service Commission (PSC) is considering this issue. Ohio and Pennsylvania have issued rulings on competitive bidding and allowance trading. If a utility competes with an independent power producer for the building of new generation resources through the bidding process and the utility loses, it must provide the independent power producer with SO_2 allowances for the project. New York is currently considering this issue.

4 EFFECTS OF STATE LEGISLATIVE AND REGULATORY ACTIONS ON UTILITY COMPLIANCE PLANNING

Title IV has resulted in the imposition of a market-based approach to pollution control on an industry characterized by a high degree of regulation and entry barriers. Flexibility and freedom of compliance choice are the keys to the successful operation of the SO_2 allowance program. In a competitive market, freedom of choice, initiative, and flexibility are inherently tied to a symmetry of risks and rewards; a firm in a competitive market has the ability to be successful and reap the rewards of "good" choices or suffer from "bad" choices. However, regulation of the electric utility industry has resulted in reduced freedom of choice. As such, in many respects, the symmetry of risks and rewards has been seriously distorted.

Utility compliance choices will be driven by differences in the costs and flexibility among the alternative compliance options that are available. Differences in costs and flexibility will, in turn, be influenced by a variety of players. The state PUCs and the Federal Energy Regulatory Commission (FERC) have the potential to significantly affect the operation of the allowance market. In particular, the manner in which issues concerning ratemaking, allowance accounting, and various strategy reviews (e.g., prudency and used-and-useful tests) are treated by the regulatory agencies will influence the structure of rewards and risks. The actions taken by regulatory agencies will thus influence the compliance planning of affected utilities. The Internal Revenue Service (IRS) will also play a role in determining how the new program operates because losses and earnings generated by allowances will have tax consequences. Consequently, the IRS has been prompted by both private and public organizations to issue guidance to utilities with respect to those issues.[23]

In addition to "rate and review" regulatory agencies, state governments may attempt to influence utility compliance choices. Because the SO_2 program will alter electric generation choices across the nation, certain states may experience adverse economic or environmental impacts. Those states that perceive themselves as bearing the brunt of the program's adverse impacts may enact legislation to minimize potential losses.

This chapter explores the possible actions of PUCs, the FERC, the IRS, and individual states that could affect utility compliance choices and the performance of the allowance market. Both the actions that might be taken and their consequences are examined.

4.1 STATE LEGISLATIVE ACTIONS

State legislative actions can be divided into four categories: (1) actions designed to promote the use of a particular in-state resource, (2) actions designed to prevent the degradation of environmental quality in the state, (3) actions designed to preserve a pool of

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[23] Internal Revenue Service, Advanced Revenue Ruling 92-16, February 27, 1992.

low-cost allowances to accommodate future economic growth, and (4) energy planning actions. The first three of these categories relate directly to the impacts of utility compliance choices and allowance trading on the amount of economic activity in a state. The fourth category, which includes energy planning actions and state-mandated rate actions (such as integrated resource planning, conservation requirements, and cost allocation), may also have impacts on Title IV compliance planning. However, in many cases, such actions have not been implemented in response to the CAAA of 1990.

4.1.1 Adverse Economic Impacts

According to a report issued by NERC (1992), approximately 49% of all Phase I compliance plans involve fuel switching to lower-sulfur fuels. States with large high- sulfur coal reserves, such as Illinois, Indiana, Ohio, and Pennsylvania, expect to lose coal mining jobs in Phases I and II. The loss of jobs is expected to result in decreased economic activity and lower tax revenues in the affected states. The principal losers from utility fuel switching/coal blending will include those areas in the Illinois Basin and Northern Appalachian Basin with high-sulfur coal seams. By the year 2000, the Northern Appalachian Basin will lose an estimated 15 million tons of coal production per year; the Illinois Basin is expected to lose 41 million tons of coal production per year (Hewson et al. 1992).

State governments have an incentive to maintain and improve local economic conditions. Several legislative approaches are available that can be used to encourage the continued use of local high-sulfur coal resources (and other in-state coal reserves). Such policies include:

- Mandating that a proportion of total coal burned be produced in that state (in-state coal),
- Mandating use of particular SO_2 control options,
- Providing tax credits for continued or increased use of in-state coal reserves, and
- Offering direct subsidies for the adoption of particular SO_2 control options.

Examples of the first two types of policies include actions in Oklahoma and Illinois. Oklahoma passed legislation requiring that 10% of all coal burned by utility units in the state be from in-state sources. However, the requirement was challenged in federal court by the state of Wyoming.[24] The Supreme Court subsequently ruled that the law was an unconstitutional restriction on interstate trade.

[24] *Utility Environmental Reporter*, October 30, 1992.

In 1991, Illinois passed a law requiring all coal-fired power plants with a generating capacity of at least 500 MW to install SO_2 control devices. The purported intent of the law was to facilitate the addition of scrubbers at the Kincaid and Baldwin generating units. In exchange for the mandate of scrubbers, Baldwin was to receive a subsidy in conjunction with the Clean Coal Technology Demonstration Project to finance completion of the scrubber. Kincaid's parent company would be allowed to incorporate existing coal contract costs for Powder River Basin coal into its rates. However, a series of events and the relative vagueness of the term "SO_2 control device" has led both units to opt out of scrubbing in Phase I. Instead both units will achieve compliance by switching to local low-sulfur coals.

Mandates requiring the use of specific resources and control options directly interfere with a utility's choice of least-cost compliance options. Consequently, mandates may lead to choices that prevent the utility from achieving compliance at least-cost. However, viewed from the perspective of the state's economy, such policies may entail lower costs than allowing compliance flexibility. In effect, "mandate" policies provide a cross-subsidy from one segment of the state's economy to another. To see how this can happen, assume that a mandate leads a utility to select a compliance option that is not the least-cost means of compliance but that does result in continued use of coal mined in the state. In this situation, the utility's customers would experience a larger rate increase than would have occurred if the least-cost compliance option had been chosen. The added costs incurred by ratepayers would indirectly subsidize continued mining employment, resulting in a transfer of wealth from one group (utility customers) to another (the mining industry).

Incentive policies, such as the use of tax credits and subsidies, distort the relative costs of compliance options such that in-state resources (i.e., coal) become relatively cheaper. For example, the states of Pennsylvania and Ohio have instituted tax credits for increased coal use. In-state utilities that increase their coal use beyond 1990 levels will receive a tax credit of $1 per ton of additional coal used. In effect, use of in-state coal is made more attractive, thus discouraging fuel switching and possibly other options that would reduce unit utilization.

Subsidies typically have been directed toward the use of devices such as technologies to clean coal, advanced boilers, and alternative flue gas treatment options. These programs are usually run by a state's coal development authority. In addition to purely state-funded technology programs, the Department of Energy's Clean Coal Technology Demonstration Program has been subsidizing the development of various coal-using technologies. In response to Title IV, several states have offered to jointly fund scrubber and boiler repowering efforts. Technology subsidy programs alter the relative costs of compliance options. Because these options usually result in the removal of large quantities of SO_2 without changing fuels, the use of in-state coal resources is maintained.[25]

[25] In some cases, tax credits and subsidies are used to address the issue of information externalities and risks inherent in the development of precommercialized technologies. Clean coal technology and renewable technology programs are examples of precommercialized technologies that require public funding to reduce externality and risk pressures.

Subsidy and tax credit programs also result in cross-subsidies. In this case, the citizens of a state subsidize certain compliance activities through increased taxes or decreased public services. Wealth is transferred from taxpayers ("the public") to the mining industry and the utility receiving the incentive.

The use of incentives and mandates has become the subject of considerable debate among the states. Wyoming and other low-sulfur coal states that stand to economically benefit the most from Title IV are concerned about the pattern of recent coal legislation. In a letter to the EPA, Governor Sullivan of Wyoming warned against protectionist measures that would inhibit Title IV compliance. In mid-1992, the Oklahoma coal law was stuck down after the state of Wyoming brought suit. At present, the status of the laws favoring local coal use in Illinois, Indiana, Ohio, and Pennsylvania is uncertain because of potential suits from low-sulfur coal producers. In the meantime, utilities continue with their Phase I compliance plans.

4.1.2 Adverse Environmental Impacts

The Title IV program targets emissions rather than ambient concentrations of SO_2. While overall SO_2 emissions will decline in the United States, concentrations may not be greatly reduced in all areas. Some states will have an incentive to implement policies designed to prevent an increase in ambient SO_2 concentrations at sensitive sites within their boundaries. Visibility concerns in the East, along with other air quality issues, may prompt states to encourage or require certain SO_2 control options. Legislative mechanisms that could be used include:

- Restrictions on the transfer of allowances to certain emission sources,
- Mandates/incentives to use certain SO_2 control options, and
- State SO_2 emission control laws.

Restricting allowance transfers would potentially require in-state utilities to report the buyers/leasees of their allowances. If it is determined that the buyer/leasee would potentially contribute to increased acidic deposition in sensitive areas, the trade might be prevented. A more restrictive policy would be to limit all out-of-state transfers of allowances. An illustration of this approach involves a conflict has that developed over Long Island Lighting Company's (LILCO's) agreement to sell excess allowances to an undisclosed source. The Adirondack Council in New York has appealed to the New York Department of Environmental Protection and the New York State Public Service Commission in an effort to discourage trades that would result in allowance trading to "upwind" sources. Coincident with the debate over allowance transfers to areas upwind of sensitive areas, EPA is required to conduct a study of the impact of acid deposition on the Adirondacks area.[26]

[26] Section 901(d)(2)(f).

Restrictions on trading allowances will result in efficiency losses of uncertain magnitude. Furthermore, it is not clear to what extent such a policy will prevent degradation to sensitive areas. The magnitude of the losses from restrictions on allowance trading will depend on the costs of the alternative compliance options that utilities are required to adopt as a result of the restriction on trades. In the case of preapproved trades or restrictions that only allow trades among certain agents, the magnitude of the loss will depend on the relative marginal control costs and which parties are forced out of cost-effective trading.

As a practical matter, little may be done to avoid environmental degradation that results from allowance trading. For example, assume that allowances were sold by a utility located in a sensitive area to another utility that did not impact the sensitive area. These allowances could then be transferred from the second utility to a third utility that would impact the sensitive area. A recent allowance trade between United Illuminating of Connecticut and an unnamed midwestern utility suggests that the restrictions proposed for LILCO may not protect sensitive areas. About the only conclusion that can be drawn regarding the overall impact of the limited allowance restriction is that allowance prices will be distorted by such restrictions. In addition, it is unlikely that the policy will significantly reduce potentially adverse impacts of allowance trading on sensitive areas.

Another possible strategy to limit damage to sensitive areas would be to impose mandates on, or provide incentives to, offending plants to reduce emissions. Mandates or incentives to use specific control options would be targeted at those units in which certain control alterations could produce increased environmental benefits (e.g., improved visibility, decreased acidic deposition, improved local air quality). This strategy tends to be unrelated to Title IV requirements and is instead incorporated into state implementation plans (SIPs) to address visibility concerns. Under a SIP, units adversely affecting a Class I area can be required to reduce emissions or install certain control technologies.

Several states established SO_2 emissions legislation before passage of the CAAA of 1990. Among states affected by Phase I, New York and Wisconsin instituted measures to limit the emissions of utility SO_2. In addition, many states have established fuel sulfur limits and SIP-driven emission limits. As a result of these "pre-CAAA" emission control requirements, utilities in these states are more advanced in the compliance process and in some cases will generate surplus allowances in Phases I and II.

Another state goal that may encourage legislative action designed to alter allowance trading and compliance strategies is the desire to maintain a pool of low-cost allowances available for future economic growth. The SO_2 emission allowance program allocates allowances at zero cost to each utility unit affected by the program. The allowances may then be transferred among the units of a utility, banked, sold, or leased to other parties. New utility units emitting SO_2 will receive no allowances and must purchase or receive allowances from other sources. From the utility's perspective, the decision whether to sell or bank an allowance is based on the relative opportunity costs. The firm holding the allowance will choose the option that generates the highest return. From a state's perspective, the measure of opportunity cost may differ.

If growth in the future requires additional allowances, there are two potential sources. First, the initially allocated allowances may be used to offset SO_2 emissions from new generating sources. In this case, rates would be unaffected because these allowances are treated in the accounting procedures as having zero cost. Alternatively, utilities may have to purchase allowances from out-of-state or other nonaffiliated, in-state sources. Purchasing allowances could result in increased rates to the utilities' customers. In order to preserve a pool of zero cost allowances, trading could be restricted to in-state sources only. Utilities in the state would be forced to forego the gains that could result from selling outside the state. However, the state would gain a relatively low-cost means of accommodating economic expansion.

Finally, state legislatures have the ability to influence utility compliance choices through energy planning and regulatory requirements. The most common energy planning/regulation option instituted in state legislatures is integrated resource planning (IRP) or least-cost planning (LCP). Integrated resource planning entails both short-term and long-term demand and energy service planning. The optimal plan is determined through examination of various demand and capacity options under a variety of assumptions about risks and uncertainties.[27] IRP differs from past utility capacity planning in that the options of demand-side management; transmission and distribution expansion/upgrades; and power purchases from other utilities, cogenerators, and independent power producers are considered along with traditional capacity expansion.

Utility compliance planning resembles an IRP plan insofar as risk analysis, screening criteria, and modeling are used to identify a set of generation and compliance options that minimize expected costs while maintaining a minimum level of reliability (see Section 2.3.2). As indicated by Rose and Burns (1992), if compliance with the CAAA is not included in a utility's IRP process, the result will be something other than a least-cost solution. Addressing compliance planning within the IRP framework has the potential to move a utility toward the "least-cost" solution because it entails consideration of the full range of generation, conservation, and compliance options. Given the emphasis on planning and thorough examination of options, the use of IRP should not unduly bias utility choice toward any one option and should motivate improved decision making.

States have also used regulatory tools to encourage options favorable to state concerns and reduce undue risks from the new allowance market. Instruments such as CWIP and preapproval under certain conditions have been allowed. While state-instituted, such instruments are administered by the state PUC and are discussed in greater detail in the next section.

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[27] Because of uncertainty and risk, the IRP process will examine several alternative scenarios and choose the combination of resources that is relatively robust and minimizes expected costs. For an expanded examination of risk and uncertainty see Hirst and Schweitzer (1990).

4.2 PUBLIC UTILITY COMMISSION ACTIONS INFLUENCING UTILITY COMPLIANCE CHOICE AND ALLOWANCE MARKET FORMATION

State PUCs address three issues directly influencing utility compliance planning: planning and review, ratemaking, and interstate/regional transactions. Planning issues include (1) the use of IRP for utility compliance planning, planning review, and prudency of plan examinations; and (2) allocation of market and regulatory risk among shareholders and ratepayers. Ratemaking issues include the treatment of allowances in rates, the treatment of alternative compliance strategies, timing of compliance cost recovery, and incentive regulation. Multistate holding and utility company compliance planning review and regional compliance planning will also be addressed by the PUCs, most likely in conjunction with the FERC or possibly a regional transmission group (RTG).

4.2.1 Planning and Reviews

A chief concern of many utilities is the recovery of compliance expenditures.[28] This concern can be attributed to two factors. First, the regulatory compact has been strained over the past two decades as utility efforts to include expenditures on generation in the rate base have been denied or delayed in an increasing number of instances. Second, the choice of SO_2 control options rests with the affected utility (in most cases), which exposes the complying utility to a variety of new risks. In the past, environmental policies have tended to mandate specific technologies or emission standards, the costs of which were incorporated directly into the rate base. In exchange for the greater flexibility offered under Title IV, utilities are now exposed to several risks when planning Title IV compliance activities. Market technology and regulatory risks generated by the allowance program all have made planning more difficult.[29]

Market risks include fluctuations in allowance and fuel prices that could potentially alter least-cost compliance strategies over time. Technology risks include the choice of a technology that is rendered obsolete in a short time. Regulatory risks relate directly to the issue of cost recovery. Because of market risks, uncertain allowance and fuel prices, and future environmental regulation, what constitutes the least-cost strategy in one time period may not be the least-cost strategy in another period. In such a case, the question arises whether the utility decision was a prudent one, and who should bear the price of such a decision. It is here that issues of planning and risk/reward symmetries become important.

Another potential risk faced by utilities is system reliability. Utility compliance with SO_2 and NO_x emission reduction requirements of Title IV, the installation of continuous emission monitors, and potential compliance with NO_x requirement of Title I is being achieved within a short planning and installation period. Because many utilities within the

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[28] As indicated by Cincinnati Gas and Electric's SO_2 compliance plan (Cincinnati Gas and Electric 1992), the principal concern of compliance planners was recovery of expenditures either through the rate base or passthrough.

[29] See Rose et al. (1992) for an examination of these risk issues.

MAIN, ECAR, SERC, and MAAC power pools will be installing their control options concurrently, reliability could suffer. Losses in reliability could increase costs to many utilities and even result in outages.

Prudency reviews and used-and-useful tests may result in a decision to exclude certain capital and other expenditures from the rate base. Prudency reviews address questions of poor judgment, bad management, inefficiency, and the like on the part of a utility. The purpose of the used-and-useful test is to determine whether a particular plant or similar project is needed at the present time. The used-and-useful test may lead to a delay in incorporating a project's costs into the rate base. In response to these reviews and large market risks, a utility will tend to choose those options that reduce risks (i.e., those options that historically have received favorable treatment). Not surprisingly, this type of "hedging" behavior may not produce the least-cost compliance plan.

At least two potential solutions exist to the problems posed by regulatory risk. In the first solution, regulators avoid the application of retrospective prudency reviews. The second solution involves the preapproval of compliance plans. This latter approach has been implemented in several states. In general, to gain preapproval, the proposed compliance plan must be supported by an IRP or similar type of analysis. Preapproval of compliance plans would restrict retrospective prudency reviews. Note, however, that preapproval does not imply preapproval of expenditures; thus, a utility still has an incentive to minimize its expenditures.

Market fluctuations in fuel prices and allowances will mean potentially greater costs or benefits than initially expected. The allocation of these rewards/losses affects both planning and ratemaking decisions. The PUCs will allocate benefits and losses through a variety of mechanisms.[30] Benefit/loss risk symmetry between shareholders and ratepayers will encourage efficient compliance planning and behavior on the part of a utility. Risk asymmetries, however, will bias decisions towards activities that minimize expected losses or maximize gains.

Planning issues are directly connected to ratemaking. Planning is directly affected by how various generation, conservation, and compliance options are treated. For instance, several parties have indicated that one reason for the lack of demand-side management (DSM) activities on the part of utilities is that these activities would result in decreased sales and consequently lower revenues (Reid and Brown 1992). Thus, even if DSM is the lowest-cost means to meet energy needs, it will not be used. Compliance planning will be influenced

[30] Mechanisms that have been suggested to recoup losses, gains, and expenditures associated with compliance that include the traditional rate hearing, fuel adjustment clauses, allowance adjustment clauses, periodic compliance cost reviews in conjunction with annual or biannual IRP updates, and environmental surcharges.

in a similar manner. An option that results in reduced revenues is at a relative disadvantage compared with options that leave revenues unchanged.[31]

4.2.2 Ratemaking Issues

The second category of PUC decisions addresses ratemaking issues. Ratemaking, as it relates to compliance choice, includes three issues: (1) the timing of compliance cost recovery; (2) rate treatment of alternative compliance options, including allowances; and (3) the use of incentive regulation. Examination of the impact of these factors on compliance behavior stems from the Bohi and Burtraw (1992) model of utility compliance behavior. Essentially, the combination of compliance measures selected by a utility is a function of the relative prices of the various measures, the relative return offered by regulation, and the marginal rates of substitution between inputs.[32] If the net regulatory returns are greater than or less than the market return, choices among options will be distorted. The regulatory returns can diverge from market returns in a variety ways: (1) depreciation rates may not match the economic rate; (2) certain options may receive rewards in excess of or below a comparable option's market return; (3) the timing of the return on an option may differ; and (4) the risks associated with the option under market conditions versus regulated conditions may differ.

The timing of compliance cost recovery refers to the questions of when and through what regulatory process expenditures enter into rates. Traditionally, rate hearings occur on a periodic basis when a utility adds new capital or incurs new expenditures. Because of the nature of rate cases and delays inherent in the process, the timing of expenditures and the return on those expenditures may diverge. To account for capital expenditures and related financing charges, an "allowance for funds used during construction" (AFUDC) and "construction work in progress" (CWIP) have been used. AFUDC allows the utility to earn a return on the carrying cost of an investment. In the rate case, the plant's entire cost can

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[31] The issue of the Averch-Johnson effect is widely cited in the literature. The basic premise is that utilities will choose the option that generates the greatest return, rather than an option that minimizes costs to rate payers. The presence of PUC prudency review, power pools, and growing competition makes the effect of less importance.

[32] Bohi and Burtraw (1992) examine the optimum combination of allowances and other compliance methods. The optimum occurs where the marginal rate of technical substitution equals the marginal economic rate of substitution with the inclusion of regulation. Mathematically this is expressed as:

$$dA/dZ = (c/p)/(\beta/\alpha)$$

where

A = number of allowances held,
Z = amount of pollution abatement,
c = price of pollution abatement,
p = price of allowances,
β = net regulatory return on abatement, and
α = net regulatory return on allowances.

then be entered into the rate base. CWIP allows the direct costs of capital equipment to be entered directly into the rate base as funds are expended. In other words, AFUDC accounts for costs of waiting for a rate case to include recent capital expenditures, and CWIP enters capital expenditures as they occur (Kahn 1988). In the past, many capital expenditures for Clean Air Act compliance have been entered into the rate base through CWIP.

In addition to CWIP and rate case mechanisms for entering costs into rates, fuel adjustment clauses (FACs) and other surcharges have been used to automatically enter changes in costs into rates. FACs allow changes in fuel prices to enter rates without the need to convene a rate case to adjust rates. Several parties have suggested implementing an allowance adjustment clause to take into account the fluctuations in allowance prices, and in effect treat them as a fuel expenditure. Kentucky has instituted an environmental surcharge to accommodate expenditures required to comply with the Clean Air Act. The mechanism is similar to CWIP in that expenditures are directly entered to rates without a rate proceeding.

The manner in which the costs of compliance options are treated in the rate structure will also influence the choice of specific compliance options. Following Bohi and Burtraw (1992), if an abatement option earns a net positive rate of return, a utility will tend to choose that option over other options (unless those other options have greater positive net returns). For example, capital costs that would include FGD expenditures are entered into the rate base and receive a return. If the regulatory return is in excess of the market return on a similar capital expenditure, the utility will acquire the option to nonoptimal levels. If, however, the net return is negative, the utility will avoid the expenditure, although the use of that option may be the least-cost compliance choice.

Incentive regulation has been proposed as a means of eliminating the distortions caused by rate-of-return regulation. Only PSI Energy has filed an incentive regulation plan for the control of SO_2 emissions. Under this plan, a tracking mechanism would be implemented to update costs automatically and include them in rates on a quarterly basis. A deadband would be established around a compliance cost level based on the price of allowances. If costs fall below the deadband, savings would be divided equally among the ratepayers and shareholders. This mechanism would allow the utility to profit from wise allowance transactions and would encourage the use of allowances. Rose et al. (1992) propose that utilities be offered the option to "buy" allowances from the utility's ratepayers. In this scenario, a PUC would determine the proportions of allowances owned by ratepayers and shareholders. The utility could then purchase allowance "rights" from the ratepayers at some PUC/market-determined price. Subsequently, all gains and losses associated with the allowances owned by the utility would accrue to the utility's shareholders.

4.2.3 Multistate/Regional Compliance Issues

Several multistate compliance issues must be addressed by the PUCs. The particular issues include (1) regional, multiutility compliance planning, and (2) treatment of compliance plans of multistate utilities and utility holding companies.

Title IV compliance planning could result in a significant burden for multistate utilities and holding companies. In particular, such firms could be required to go to each state with regulatory authority over their actions to seek approval of the proposed compliance plan and inclusion of the relevant compliance costs. Such entities are thus presented with additional regulatory risks because of the multiple regulatory forums. Inconsistent treatment of compliance options and plans among the various states would make compliance planning for multistate utility systems even more difficult.

Both the New England Conference of Public Utility Commissioners and the Northwest Electric Power Planning Council engage in multistate coordinated utility planning and regulation. These councils provide an administrative forum for addressing issues related to regional Title IV SO_2 compliance planning and the provision of power. Multistate coordination of compliance planning and generation offers a means of reducing compliance costs for the utilities in the region. A coordinating administrative body could ease compliance cost disputes among individual state regulatory bodies. Regional bodies could offer better means of applying region-specific solutions to compliance problems than could regulatory organizations unfamiliar with a particular region's needs.

4.3 FEDERAL ACTIONS AND UTILITY COMPLIANCE PLANNING

The FERC is responsible for regulating interstate commerce in electricity and natural gas and will be required to address issues of ratemaking and allowance transactions, compliance and multistate holding companies, and regional compliance planning. In light of the growing reliance on utility power pools for reliability and low cost energy and the growing wholesale markets for electricity, FERC will play an important role. However, no official proposals or actions have been taken by FERC on these matters. To date, action by the FERC has been limited to issuing a proposal to revise utility accounting rules to include allowances.

The Notice of Proposed Rulemaking (NOPR) to revise utility accounting practices for SO_2 emissions allowances and establish generic accounts to record assets and liabilities through the ratemaking actions of regulatory agencies was issued on December 2, 1991.[33] The NOPR addresses the issues of allowance account creation and classification, allowance value accounting, inventory methods for allowances, and other topics. In the time that has since elapsed, no final accounting rules have been issued.

Two new accounts would be created to accommodate SO_2 emission allowances — an allowance inventory account and an allowance withheld account. It was decided to treat allowances as inventory because allowances have the properties of both an input to the electricity production process and a financial security. Allowances are not subject to

[33] Docket No. 92-1-000, Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A, 56 *Fed. Reg.* 64567, (December 11, 1991).

depreciation or amortization in this account. By not treating allowances as a fuel, security, or capital-related commodity, FERC considers the treatment "rate-neutral".[34]

Allowances are to be valued at historical cost, in essence the amount of cash needed to acquire the asset. Allowances initially allocated by EPA will be treated as having zero cost. Allowances sold and purchased will be valued at their selling/purchase price. For allowances acquired or sold through an exchange of services, commodities, or cash in combination with a "boot," the fair market value of the allowances will be assessed.

Allowances removed from inventory due to sale, production, or other usage will be costed by a weighted average cost method. The FERC has indicated that this procedure would prevent undue manipulation of the utility's income statement resulting from the order in which allowances were used. In addition, because allowances are generic commodities and "unnumbered,"[35] no system of first in, first out (FIFO) or last in, first out (LIFO) accounting would be required. The FERC also indicated that the weighted-average cost method would be the most general form of accounting and would therefore allow states maximum freedom in designing their accounting procedures. Allowances would be expensed on a monthly basis; gains or losses attributable to the sale/transfer of allowances would be entered into the rate process through a FAC-like mechanism or other adjustment process.

The "allowances withheld" account addresses those allowances withheld from initial allocation by EPA for direct sale and EPA's auction program. Unsold allowances and funds from the allowance sale are to be allocated to the utilities through this account.

The NOPR also addresses the issue of accounting for allowance futures transactions and allowance transfers between affiliated utilities. For futures, the NOPR suggests that the costs and benefits of hedging through the use of futures should be deferred until the transfer of rights occurs. For affiliated transactions, historical cost should be used.

Rose et al. (1992) have critiqued the NOPR on the issue of value. Under the NOPR, allocated allowances would be assigned a zero cost. However, their value to utility shareholders and ratepayers is not zero, and accounting records should reflect the value of the asset. Rose et al. (1992) also maintain that the transfer of this accounting method into a ratemaking framework could distort compliance decisions. They propose instead that ratemaking issues by the states and FERC be addressed first and accounting measures follow the design of ratemaking.

The IRS has recently issued guidance for utility accounting of SO_2 allowances.[36] Previously, the IRS issued guidance stating that allowances received as part of the EPA's

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[34] Ibid.

[35] Allowances are not serialized.

[36] Rev. Proc. 92-91, Guidance Effective Nov. 16, 1992.

initial allocation would not constitute a taxable event. In effect, the allowances would be treated as if they had no value. In the more recent guidance, the following rules were issued:

- Allowance costs must be capitalized and cannot be depreciated;
- Allowances used in a particular year can be deducted in that year;
- Capitalization of otherwise deductible expenses will be required in certain instances;
- An emission violation penalty is not tax deductible; and
- For tax accounting purposes, allowance purchases include both the cost of the allowance and the costs of its acquisition.

4.4 IMPACT OF REGULATORY POLICIES ON THE MARKET FOR SO_2 ALLOWANCES

While the discussion here and in much of the existing literature makes reference to *the* market for SO_2 allowances, in reality, allowance markets will be established to support different types of transactions. The Chicago Board of Trade (CBOT) operates a futures market for allowances. In addition, the CBOT is operating EPA's auction market. The futures market will address market risks by enabling parties in the market to speculate and hedge through the allowance contract. The risks associated with fluctuations in allowance prices can be reduced through futures contracts. In addition, some benefits may be obtained by speculation. Through speculation, risks associated with different trading actions are allocated to those parties that are most able to bear risks. Speculation, on rough transactions and risk premiums, provides price signals to other parties. Price signals in turn provide buyers and sellers with improved information, and, hence, market participants are able to make better decisions.

EPA's auction involves the purchase of allowances for immediate and long-term use. Allowances exchanged in this market come from two sources — allowances submitted by private parties and allowances taken by EPA from the initial allowance allocation. The EPA auction features two types of allowance contracts — spot contracts and advance contracts. Allowances acquired through the spot market can be used immediately or banked for use at some future date. Allowances acquired through the advance auction must be held for seven years before they can be used. In addition to making allowances available for cash sales, the EPA auction provides information on allowance prices and encourages trading.

Multilateral trading among utilities, fuel companies, and other parties constitutes a separate allowance market. Multilateral trading can consist of simple cash sales, allowance leasing, or a "boot." For example, a high-sulfur coal company could offer a coal contract that calls for the company to provide both coal and allowances for a specified price. Alternatively, a utility could offer to trade power in exchange for allowances. A variety of brokerages exist to facilitate this type of market transaction. A subset of the multilateral trading market includes opt-in sources that voluntarily enter the SO_2 program in exchange for the ability to operate in the allowance markets.

Regulatory policies, including actions designed to influence compliance choice and rules governing operation and reporting requirements for allowance transactions, have the ability to influence allowance trading and the market for allowances. The impact various policies will have in each allowance market described above is difficult to determine at this time. However, some generalizations can be made regarding the effect of various policies on the market as a whole. Policy actions (in many cases overlapping) that may influence allowance markets include:

- Mandating of specifications,
- Regulatory distortion of compliance costs,
- Risk sharing asymmetries and regulatory treatment of allowances,
- Allowance trading restrictions,
- Treatment of allowance pooling, and
- Regulatory review of trading.

At present, Ohio, Iowa, and Pennsylvania have issued rules regarding the regulatory treatment of allowances. In addition, Georgia, Illinois, Indiana, Kentucky, Missouri, New York, and Wisconsin have issued some rules regarding allowances or are in the process of formulating such rules.

4.4.1 Regulatory Distortion of Compliance Costs

Regulatory distortion of compliance costs refers to a change in the relative prices of fuels, flue gas treatment costs, and other SO_2 control options resulting from the implementation of a specific policy, such as rules governing the rate treatment of certain costs, mandates, or tax credits/subsidies. Altering of relative prices of compliance options may influence compliance choices and allowance holdings. For example, a regulatory policy that successfully encourages scrubbing, either through rate treatment or tax/subsidies, would free up allowances that could be banked or sold. The likely impact of such a policy would be a reduction in allowance prices as the supply of allowances increased. The result in the allowance market would be an equilibrium price that was lower than the price that would prevail if compliance choices were based solely on market considerations. An efficiency loss would occur to the extent that more resources were allocated to scrubbing than would occur in the absence of market intervention. Whether policies favoring differing compliance options will actually influence compliance planning is unclear. In Phase I, even in high-sulfur coal states, the predominant compliance strategy is fuel blending/switching along with altered utilization rather than increased use of FGD methods.

4.4.2 Risk Sharing Asymmetries and Regulatory Treatment of Allowances

Risk sharing asymmetries also influence relative compliance costs. In this case, the principal concern is cost recovery and the rewards/penalties associated with the sale or purchase of allowances. Utilities will tend to choose those strategies that guarantee regulatory cost recovery. The choice of strategies will be based, in part, on past treatment of certain actions and current policy. As such, certain strategies may tend to be avoided because of the regulatory risks involved. The allocation of the rewards/penalties will influence the incentives to participate in the allowance market. This issue is directly linked to rate policy regarding allowances.

Some current or past compliance actions will free allowances for banking or sale. In most cases, the costs of these actions pass into rates. For example, capital projects such as FGD, boiler repowering, and other capital expenditures are usually entered into the rate base. In a similar manner, changes in fuel prices attributable to fuel blending/switching are incorporated into rates in the ratemaking process or through a fuel-adjustment clause. In either case, ratepayers ultimately pay the cost of these compliance strategies. From an equity perspective, it has been argued that because the ratepayers have borne the costs of compliance, the benefits from the sale of the freed-up allowances should also be allocated directly to the ratepayers. However, minimizing compliance costs entails both regulatory and market risks. As such, to encourage cost-minimizing compliance activities it might be desirable to design a regulatory framework that allows firms to retain some share of the benefits resulting from the sale of allowances.[37] The absence of such an incentive may lead to more costly compliance activities.

Policies that present risk/reward asymmetries in allowance trading tend to reduce the level of activity in the market by reducing the supply of (or demand for) allowances, depending on a utility's actions. To the extent that the supply effect dominates, a reduction in trading will tend to increase the relative cost of allowances. If the demand effect dominates, the reverse would occur. Consequently, the overall magnitude of the effect of trading restrictions is uncertain.

Regulatory treatment of allowances will influence compliance activities and the allowance market. Following Bohi and Burtraw (1992), the relative return on the use of allowances versus the relative return on the use of alternative compliance strategies will influence the extent to which allowances are used for compliance purposes. If allowances yield a net rate of return that exceeds the rate of return on alternative compliance options, allowances will be used. As the net rate of return on allowances declines, so will the use of allowances as a means of achieving compliance with emissions restrictions. In the first case, demand for allowances will be increased. In the second case, demand for allowances will be reduced. It has been suggested that to reduce regulatory distortions created by rate-of-return regulation of the allowance market, allowances freed by compliance activities should be used to offset the costs of the activity in rates. Following this, any remaining benefits from the freed allowances would be distributed between shareholders and ratepayers in some manner.

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[37] Note that utilities do have an incentive to minimize compliance costs due to regulatory review of compliance activities and competition for bulk power sales on the wholesale market.

Both Pennsylvania and Ohio have opted to treat allowance costs in a manner similar to fuel, that is, changes in costs will be passed through to ratepayers.

4.4.3 Treatment of Allowance Pooling and Allowance Trading Restrictions

Allowance pooling would entail several inter-linked utilities operating as a single system for purposes of achieving compliance with SO_2 emission limits. Allowance pooling has the potential to save utilities both transactions costs and compliance costs because allowances would be readily available and potentially less expensive. Restricting or limiting pooling by regulatory means could result in greater compliance costs. The impact on allowance trading is uncertain because pooling does not necessarily restrict the flow of allowances into or out of the aggregate allowance pool.

If a state prohibited out-of-state trading of allowances that its utilities had received, compliance costs across the nation could increase. The effect would be especially noticeable if that state had received a large number of allowances. The overall market effect of such an action would be twofold. First, compliance prices would be increased as fewer allowances were available in the allowance market; second, reduction in the potential supply of allowances might create greater price volatility, increasing the level of uncertainty in the market. Restricting the trading of allowances into a state would also reduce the supply of allowances, potentially increasing the volatility of a state's allowance market and raising the costs of compliance for a state's utilities. Imposing trading restrictions such as banning trades to certain sources and requiring trading preapproval would raise the transaction costs of allowance trading and limit the potential for cost savings.

4.4.4 Regulatory Review of Allowance Trading

Regulatory review of allowance trading will affect the allowance market by influencing transaction costs. Policies that require continual review of allowance transactions, or preapproval of allowance trades, will tend to raise the transactions costs associated with trading. Trading preapproval reduces utility flexibility and could result in missed trading opportunities. This situation, in turn, will discourage the use of allowances as a means of compliance, hedging, and speculation. As the allowance markets have all indicated that they will resemble traditional commodity/financial markets, quick decisions may need to be made. Restricting decisions through continual regulatory review may limit the effectiveness of the market. Policies that encourage market participation through a reduction in regulatory risks or, as in the case of Georgia, require examination of allowances as a means of compliance if costs exceed a certain level, should encourage trading.

At present, the impact of regulatory policy on the allowance market can only be assessed on a qualitative level because of to the relative infancy of the markets. As trading volumes increase over the next several years, a more comprehensive assessment of the impact of various state regulatory policies will be possible.

5 FLEXIBILITY AND COMPLIANCE CHOICE

5.1 CONTROL SYNERGIES AND CO-POLLUTANTS

Title IV will directly or indirectly affect the entire electricity generation industry. Units using coal and high-sulfur oil will be forced, in most cases, to alter the type of fuel used or install control devices. Utilities with affected units may also alter dispatch order and utilization, which will affect the operation of every unit in a utility's system. The choice of cost-effective SO_2 compliance strategies and the adoption of efficient regulatory procedures to ensure the cost savings promised by the program are important concerns to utilities and policy makers alike. However, additional concerns must also be addressed.

Each fuel or process change adopted by a utility for SO_2 compliance will also affect other combustion emissions and by-products. The CAAA of 1990 include provisions for reducing SO_2, NO_x, and potentially hazardous air pollutant (HAP) emissions. When developing an SO_2 compliance strategy, planners must consider both the potential for co-control of pollutants associated with various options and the co-pollutants generated by those options. Ideally, planners will know the timing and the magnitude of the regulation of co-pollutants. If this information is known in advance, planners can choose synergistic control options that control one or more pollutants to required levels, or avoid installing controlling devices that increase co-pollutants to unacceptable levels. Prior knowledge of regulatory requirements eliminates options that would require modification later on and allows the planner to choose the least-cost set of options.

Regulations related to utility HAPs, increased NO_x control requirements in a potential "Phase II" of Title I, and regulation of carbon dioxide (CO_2) emissions are unknown at present. As indicated in Table 5, Phase I SO_2 compliance decisions have already been made. Many of the regulatory uncertainties are scheduled to be resolved before Phase II compliance plans are due in 1996, but delays could make even Phase II planning problematic.

5.2 FLEXIBILITY AND COMPLIANCE CHOICE

Utility compliance planning must account for fluctuations in allowance prices and fuel prices and the possibility of future environmental regulations that could render existing control strategies inappropriate. A truly least-cost compliance plan would allow the planner to adjust compliance options as both market and regulatory conditions change. However, because of the nature of capital investments and fuel contracts, flexibility is limited.

Because of the uncertainty over pollution control regulations of HAPs, a utility planning SO_2 compliance is faced with two problems. First, if the utility takes action to co-control the regulated and unregulated pollutants in question, the PUC may not allow the added costs of control into rates (i.e., the additional expenditures might not be treated as used-and-useful). If no regulation is issued on the uncertain pollutant, the utility may even face a prudency review for its actions. Second, if a utility ignores the possibility of future

TABLE 5 Utility Compliance Timeline[a]

Date	SO_2	NO_x	HAP
November 1992		NO_x RACT proposals required	
March 1993	Phase I compliance plans required	Phase I compliance plans required	
November 1993	Sensitive-areas study due from EPA		
1993			Completion of EPA, NAS studies on utility HAP emissions
April 1994	Possible revision to SO_2 NSPS	Possible revision to NO_x NSPS	
January 1995	Phase I programs begins	Phase I program begins	
June 1995		NO_x RACT compliance required	
January 1996	Phase II compliance plans required		
January 1997		Title IV NO_x emission standards issued for additional boilers	
January 1998		Phase II utility NO_x compliance plans due	
1998			Possible HAP regulation issued
January 2000	Phase II begins	Phase II begins	

[a] Definitions of terms: EPA = U.S. Environmental Protection Agency; HAP = hazardous air pollutant; NAS = National Academy of Sciences; NSPS = New Source Performance Standard; RACT = reasonably available control technology.

regulation of pollutant "x", it risks the danger of choosing a control option that could increase the emission of "x" or make retrofit controls of "x" difficult and costly if regulations are eventually issued. The SO_2 allowance market offers some flexibility and the opportunities to delay choosing drastic fuel or technology control modifications through alternative compliance means, such as allowance offsets, allowance purchases, conservation programs, altered utilization, and fuel blending. However, some utilities must still commit to long-term, relatively inflexible control options for a large proportion of their units.

Particular SO_2 compliance options could be "winners" or "losers," depending on the uncertain pollutant controlled. Several FGD systems offer significant SO_2 removal efficiencies and also are extremely effective in removing trace metal HAPs and mercury. In addition, a significant amount of allowances are freed for banking and use as offsets for other units, delaying controls for those units. The drawbacks associated with the technology are its large capital costs, which make the technology relatively inflexible,[38] its parasitic energy requirements, and its generation of significant solid waste.[39] Parasitic energy requirements lower the capacity of a unit and because of added energy required emits more CO_2 per usable kilowatt hour (by ratepayers).

Fuel switching and fuel blending are seen as options that can effectively reduce SO_2 emissions and provide some flexibility to switch to a different control option in the future. However, fuel switching currently requires expenditures to modify boilers and coal handling/storage procedures because of different heat values, ash content, and the like. Switching to western coals has also been associated with increased ash and requirements to modify particulate control processes. Switching to coal of low heating value can also lead to a reduction in available capacity. Switching to certain coal grades can increase emissions of some HAPs. The fuel blending option tends to be less expensive (because modification requirements are reduced) and thus could be considered a more flexible strategy. Natural gas co-firing is considered an ideal means to address the problem of SO_2 and NO_x emissions and also effectively reduces several HAPs and the volume of combustion waste. Boiler repowering is also seen as means of effectively reducing SO_2 and NO_x, as well as HAPs, CO_2, and combustion wastes. However, the higher capital costs associated with this option may prevent its widespread application in the near term.

Compliance planning for SO_2 emission reductions is affected by concerns other than the market. The issue of co-pollutants and control synergies will grow as more regulatory requirements associated with the indicated pollutants are promulgated. In the meantime, maintaining compliance flexibility seems to be the key means of meeting this challenge.

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[38] Once the cost of the FGD has been entered into the rate base, it would be difficult for a utility to write off the expenditure if the FGD was found to be inappropriate given new environmental regulations and control requirements.

[39] Some FGD processes produce a readably useable by-product, such as wall-board-quality gypsum and elemental sulfur. In addition, FGD waste products have been used as filler material, fertilizer, and as a component to cement.

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APPENDIX A:

CODED COMPLIANCE STRATEGIES FOR THE UTILITY COMPLIANCE DATABASE

1. **Fuel-Related Strategies**

   1.1 Coal blending/trimming
   1.2 Coal fuel switching
   1.3 Natural gas co-firing
   1.4 Additional/advanced coal cleaning

2. **Flue Gas Treatment**

   2.1 Wet lime/limestone flue gas desulfurization
   2.2 Spray dryer/dry flue gas desulfurization
   2.3 Sorbent injection

3. **Boiler Repower**

4. **Dispatch/Utilization**

   4.1 Unit designating substitution/compensating
   4.2 Conservation
   4.3 Power purchases
   4.4 New unit replacement/greenfield
   4.5 Retiring unit
   4.6 Sulfur free reduced utilization

5. **Allowance Strategies**

   5.1 Purchase allowances
   5.2 Allowances from offset on system

6. **No Strategy**

   6.1 Existing controls meet requirements/no action
   6.2 No strategy/plan indicated

APPENDIX B:

CODED ACTION CATEGORIES FOR THE STATE REGULATORY DATABASE

1. State Mandates

1.1 Coal use requirement
1.2 Technology requirement

2. State Incentives

2.1 Coal use tax credit
2.2 Technology subsidy

3. State Environmental Programs

3.1 Preexisting acid rain/SO_2 law
3.2 Sensitive area protection

4. Planning Issues

4.1 IRP process
4.2 Preapproval
4.3 Prudency issue
4.4 Risk/reward indicator

5. Ratemaking

5.1 Surcharge/rate recovery mechanism
5.2 Incentive regulation
5.3 Allowance valuation
5.4 Bidding rules/allowance allocation

6. Regional/Interstate

6.1 Multistate planning
6.2 Coincident, multistate approval of options

DATE

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5/12/94

END