

Report to the Chairman, Environment,
Energy, and Natural Resources
Subcommittee, Committee on
Government Operations, House of
Representatives

December 1994

AIR POLLUTION

Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost





United States
General Accounting Office
Washington, D.C. 20548

**Resources, Community, and
Economic Development Division**

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December 16, 1994

The Honorable Mike Synar
Chairman, Environment, Energy,
and Natural Resources Subcommittee
Committee on Government Operations
House of Representatives

Dear Mr. Chairman:

As you requested, this report examines the emissions trading program created by the Clean Air Act Amendments of 1990 to control acid rain. To increase the effectiveness of this program, we are making several recommendations to the Administrator of the Environmental Protection Agency (EPA) and the Chair of the Federal Energy Regulatory Commission (FERC).

As arranged with your office, unless you publicly release its contents earlier, we will make no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies to appropriate congressional committees, the Administrator of EPA, the Chair of FERC, the Secretary of Energy, and other interested parties. We will also provide copies to others on request.

Please call me at (202) 512-6111 if you or your staff have any questions. Major contributors to this report are listed in appendix II.

Sincerely yours,

A handwritten signature in black ink, appearing to read "Peter F. Guerrero". The signature is stylized with a large, looped "P" and "G".

Peter F. Guerrero
Director, Environmental
Protection Issues

Executive Summary

Purpose

In 1990, the Congress adopted a new regulatory approach to reduce acid rain, allowing electric utilities to trade allowances to emit sulfur dioxide (SO₂), a major cause of acid rain. Utilities that reduce their emissions below the required levels can sell their extra allowances to other utilities to help them meet their requirements. EPA estimates that this flexible approach to curbing acid rain could reduce costs significantly because trading allowances can be less costly than other methods of controlling pollution.

Interested in the potential of such trading, the Chairman of the Environment, Energy, and Natural Resources Subcommittee, House Committee on Government Operations, asked GAO to determine (1) the extent to which trading is expected to reduce SO₂ emissions and compliance costs, and the status of the allowance trading market; (2) impediments to increased trading of allowances; and (3) the implications for designing a similar approach to curb carbon dioxide (CO₂) emissions.

Background

Title IV of the Clean Air Act is designed to achieve a 10-million-ton annual reduction in SO₂ emissions from 1980 levels by the year 2010. Of this reduction, 8.5 million tons is to come from electric utilities, the nation's major source of SO₂ emissions. The reduction is to be implemented in two phases. In Phase 1, the 110 utility plants with the highest levels of emissions must reduce their annual emissions by 3.5 million tons beginning January 1, 1995. In Phase 2, beginning January 1, 2000, almost all utilities must reduce their annual emissions by another 5 million tons. Unlike the traditional command-and-control approach, in which the regulator specifies how to reduce pollution or what pollution control technology to use, title IV gives utilities flexibility in choosing how to achieve these reductions. For example, utilities may reduce emissions by switching to low-sulfur coal, installing a pollution control device called a scrubber, or shutting down a plant. Title IV also allows trading in emission allowances. Based on formulas in the law, each utility receives a fixed number of allowances. Specifically, an allowance is an authorization to emit 1 ton of SO₂. Once the allowances are allocated, the act requires that annual SO₂ emissions not exceed the number of allowances held by each utility plant. To meet this requirement, a utility can buy allowances, in effect paying other utilities to reduce SO₂ emissions below their allowed levels. For some utilities, buying allowances costs less than other approaches.

Results in Brief

Reductions in SO₂ emissions and compliance costs as a result of allowance trading between utilities have been limited because little such trading has occurred to date. Rather, most utilities are selecting cost-saving opportunities within their own power plants first, such as switching from high- to low-sulfur coal, and are projecting sizable reductions in their SO₂ emissions. These opportunities, while substantial, do not exhaust the potential for utilities to reduce their current compliance costs. For instance, many utilities could have saved even more by purchasing allowances, but to date, most of the limited purchases that have occurred were made at two EPA-sponsored auctions at prices lower than many analysts predicted. In the future, substantial cost savings can be realized if more allowance trading occurs.

The low level of allowance trading to date is due to several factors. First, phasing in emissions reductions over several years reduces the urgency to buy and sell allowances. Many potential buyers, for instance, do not have to reduce emissions until much later, even though they could save costs by purchasing allowances now. A second barrier to more trading results from economic regulation of the electric power industry. State public utility commissions and the Federal Energy Regulatory Commission (FERC) regulate electric utilities' profits. To date, these commissions have provided limited regulatory guidance on trading allowances, even though trading can lower the costs of electric power by reducing the costs of complying with requirements. Another factor impeding trading is the design of EPA's allowance auction, which produces more than one winning price and has resulted in prices lower than many analysts expected, causing confusion among buyers and sellers about the price at which to buy or sell allowances. For instance, potential sellers of allowances have been reluctant to trade at these unexpectedly low prices.

Some features of the SO₂ program would be helpful in designing a similar approach to reduce CO₂. These features include an overall requirement for emissions reductions and a monitoring system and fines high enough to ensure compliance. Modifying other features, by, for example, requiring everyone to achieve the same emissions reductions simultaneously, would provide more incentive to trade and achieve cost savings. Also, designing an auction that results in a single price for allowances could make it clearer what price to expect, thus encouraging more trading.

Principal Findings

Emissions and Compliance Costs Are Falling Despite Little Trading

Reductions in SO₂ emissions are projected to exceed Phase 1 requirements, and most utilities plan, for now, to save the resulting surplus allowances to meet their higher Phase 2 requirements. At the same time, utilities are discovering cheaper ways to reduce SO₂ emissions within their own plants as a result of title IV's flexible regulatory approach, thus resulting in falling compliance costs. However, not much allowance trading has occurred despite the large savings reported. For example, one southeastern utility estimates saving \$300 million by trading.

Utilities have scant information about allowance prices, and prices have been lower than expected. The average price of an allowance at EPA's last auction was \$159, about 33 percent less than forecast. Many utilities are retaining their extra allowances rather than selling them at current prices.

Given the estimated differences in the costs of reducing SO₂ at electric power plants, more trading between utilities could result in substantial cost savings and reduce differences in compliance costs among states. Western and midwestern utilities typically have lower costs per ton of SO₂ reduced. Trading should result in allowances moving from these utilities to those in eastern and southeastern states, where the costs of reducing emissions are higher.

Various Factors Have Caused Reluctance to Trade

Phasing in the allowance market has slowed trading because likely sellers and buyers of allowances do not have to reduce emissions at the same time. In Phase 1, about 14 percent of all affected power plants must reduce emissions, excluding hundreds of plants that are not affected until Phase 2. Plants in Phase 1 generally have lower costs to reduce emissions per ton of SO₂ than plants subject only to Phase 2, making Phase 1 plants more likely sellers and Phase 2 plants more likely buyers of allowances. However, because Phase 2 plants have more time to reduce emissions, there has been less urgency to trade and, as a result, lower cost savings.

Economic regulation of electric utilities has not encouraged trading. State public utility commissions and FERC regulate utilities' profits and recovery of costs, but many commissions have offered little guidance on whether utilities can share with ratepayers any cost savings resulting from allowance trading. Therefore, utilities hesitate to trade and instead may

choose compliance options whose costs are traditionally recouped in utility rates. Also, despite the growing number of wholesale power transactions under its jurisdiction, FERC has not issued guidance clarifying how it will treat the cost of allowances in these transactions. However, competition in the industry is increasing, and some utilities and utility commissions, in their desire to lower costs and remain competitive, are becoming more disposed to trading.

Other factors have been cited as impeding trading. The design of EPA's auction has produced prices that are lower than expected, causing uncertainty among utilities about the price at which to trade allowances. The possibility that EPA will issue regulations on other air pollutants has added to this uncertainty. Concern that some trades might increase SO₂ emissions upwind of sensitive areas and damage those regions has also deterred trading. In addition, certain states require utilities to use in-state coal reserves or particular SO₂ control options, which can mean less trading. Finally, the tax treatment of allowances may discourage some utilities from trading.

Certain Features May Be Appropriate for a CO₂ Program

Because of possible environmental and economic benefits, trading could be part of a regulatory approach to curb CO₂ emissions. In designing such an approach, some features of the SO₂ program would be helpful, including an overall emissions cap combined with monitoring of CO₂ emissions and the levying of penalties to ensure compliance. Like SO₂ emissions, CO₂ emissions can be monitored for many sources.

Modifications to make in adapting the SO₂ program to CO₂ include eliminating the phased approach, thus requiring all sources to reduce emissions at the start of the program. This change would bring all prospective traders to the table at the same time, increasing the likelihood of trading and cost savings. In addition, an auction that generates a single winning price would provide more accurate prices and reduce uncertainty about prices.

Recommendations

GAO recommends that the EPA Administrator and the Chair of FERC take several actions to encourage trading in SO₂ emission allowances and achieve additional cost savings. EPA should change the design of the auction so that it is a single-price auction, and FERC should provide more guidance on how it will treat allowances in its ratemaking decisions. These

and other recommendations for improving the SO₂ trading market are detailed in chapter 3.

Agency Comments

GAO discussed the findings in this report with the Director and staff of EPA's Acid Rain Division and the Deputy Director and staff of FERC's Office of Electric Power Regulation. Their comments were incorporated where appropriate. EPA generally agreed with the facts presented. FERC officials believe that it would have been counterproductive to issue generic guidance in advance of specific requests from utilities and before the trading program could develop. However, they agreed that utility cases currently before FERC may now offer a vehicle for providing guidance and encouraging trading. As requested, GAO did not obtain written agency comments on a draft of this report.

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Abbreviations

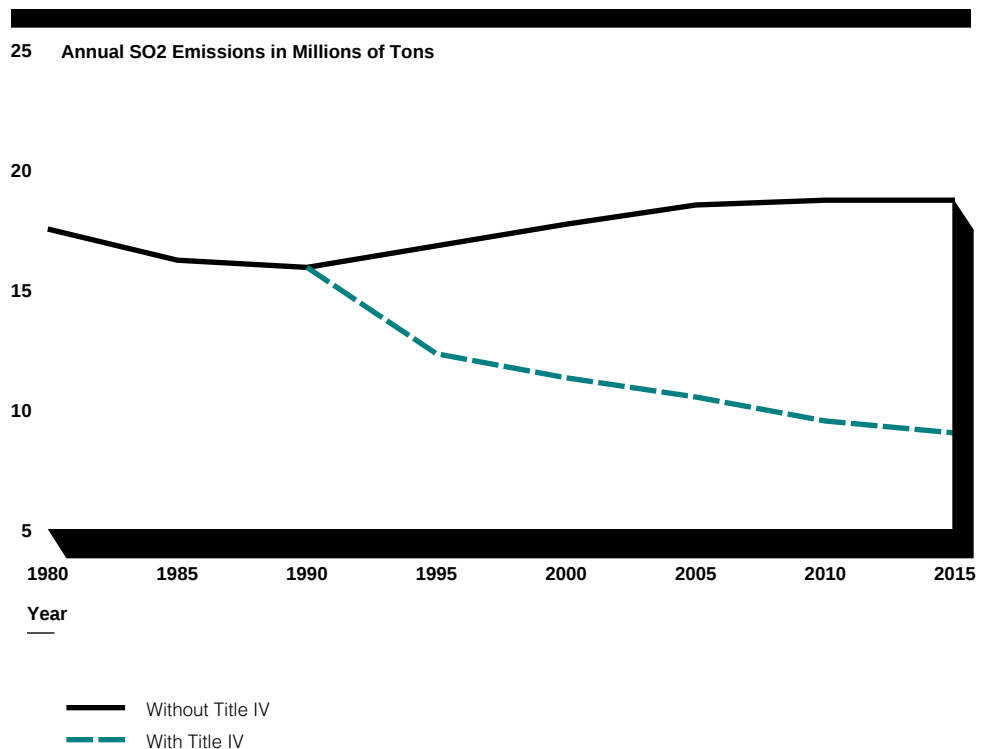
CEM	continuous emissions monitors
CO ₂	carbon dioxide
DOE	Department of Energy
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAO	General Accounting Office
IRS	Internal Revenue Service
NRRI	National Regulatory Research Institute
SO ₂	sulfur dioxide

Introduction

Controlling acid rain was a major environmental issue during the 1980s from the standpoint of both air quality and the cost of regulation. In 1990, the Clean Air Act was reauthorized; it included a program to control acid rain.

Title IV of the 1990 act limits electric utilities' emissions of sulfur dioxide (SO_2)—a major cause of acid rain.¹ It includes a regulatory system to reduce the costs of meeting these emissions limits by allowing utilities to choose cost-effective pollution controls. In title IV, the Congress combined a regulatory approach known as emissions trading with compliance measures to ensure that emissions limits are met. Figure 1.1 shows substantially lower SO_2 emissions expected over the coming decades as a result of title IV.

Figure 1.1: Estimated U.S. Sulfur Dioxide Emissions With and Without Title IV



Source: GAO's illustration based on EPA's data.

¹It also limits utilities' emissions of nitrogen oxide, which also contributes to acid rain.

Under this program, utilities receive emissions “allowances” from EPA that allow them to emit SO₂ during or after a specified year. Each utility is allotted a specific number of allowances annually; at year’s end, each must have one allowance for each ton of SO₂ emitted. By the year 2010, the program limits annual SO₂ emissions to 8.95 million tons by granting only the corresponding number of allowances to utilities.²

To help utilities reduce their costs of complying with lower SO₂ limits, they are given flexibility to choose how they will meet the overall reduction requirements of title IV. For example, they can switch to fuel with a lower sulfur content or install pollution control devices. They can also buy and sell SO₂ allowances. That is, if a utility’s cost to reduce SO₂ emissions is higher than the market price of allowances, the utility can save money for itself and its customers by purchasing the necessary number of allowances to comply with the requirements, instead of fully reducing its emissions. For these extra allowances to be available, however, another utility generally must reduce emissions below its requirement. This utility can sell its surplus allowances to utilities with higher costs at a likely profit for the selling utility and its customers.

Sulfur Dioxide Allowance Trading Marks a Departure From Traditional Regulation

Title IV is regarded as a major turning point because it uses market-based incentives to implement environmental mandates. In particular, the marketable allowance system for controlling acid rain presumes that cost-effectiveness will be the driving factor in utilities’ decisions. The new program seeks to reduce the costs of controlling pollution by providing more flexibility in how emissions reduction goals are achieved.

Acid rain is created when the SO₂ and nitrogen oxides given off in the combustion of fossil fuels react in the atmosphere to form sulfuric and nitric acids. These acids then fall to the earth, sometimes hundreds of miles downwind from their source, in wet form, such as rain or snow, or in dry form, such as small particles or gases. Many U.S. and international scientists have linked acid rain with damage to sensitive aquatic and forest ecosystems. The dominant precursor of acid rain in the United States is SO₂ from coal-fueled power plants. For example, damage to aquatic systems in New York and New England are attributed to SO₂ emissions from older coal-burning power plants in the Midwest. Electric utility plants account for about 70 percent of the nation’s annual SO₂ emissions.

²No matter how many allowances a utility holds, it will not be allowed to emit SO₂ levels that violate the national or state health-protection standards for SO₂.

During the 1980s, the Congress considered various proposals to reduce SO₂ emissions. As part of the debate, some midwestern states sought to ensure continued use of their high-sulfur coal by wanting to require and subsidize the use of pollution control technology—commonly referred to as a “scrubber” since it “scrubs” out pollution in the power plant’s stacks. As shown in figure 1.2, a scrubber is a large addition to a power plant. On the other hand, some western states saw acid-rain control as a new market opportunity for low-sulfur coal. They wanted utilities to use their low-sulfur coal to reduce acid rain and opposed the required use of scrubbers. In response to these competing interests, in 1989 the Bush administration proposed using an allowance trading system to control acid rain, and the result was title IV.

Figure 1.2: Example of a Scrubber

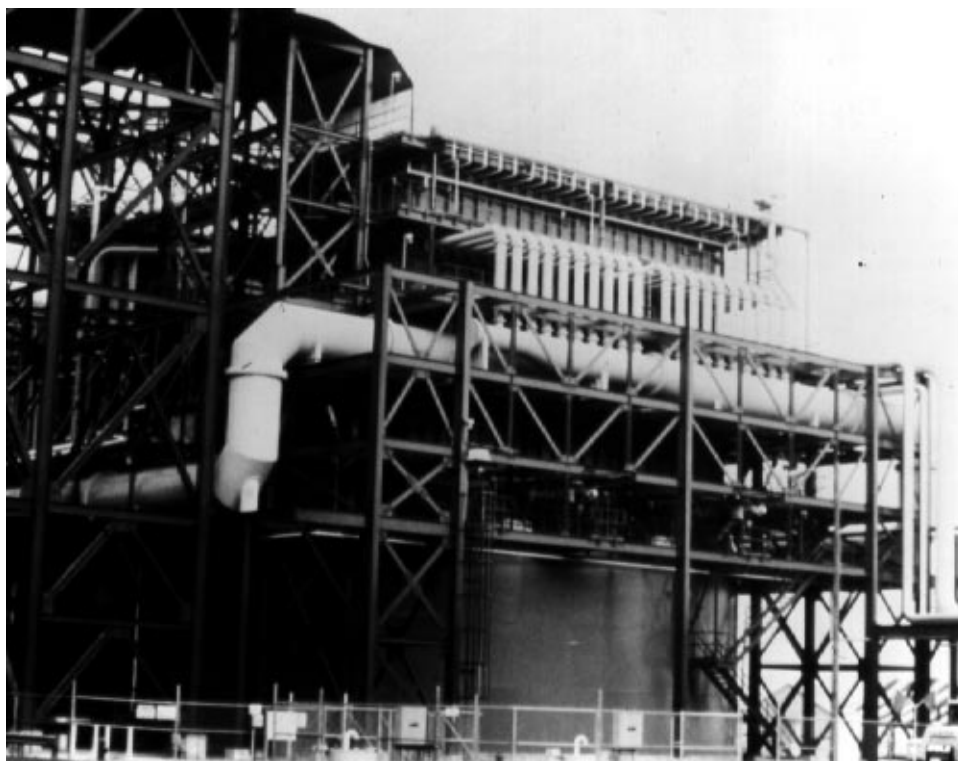


Photo used by permission of Air Products and Chemicals, Inc.

The allowance trading program differs from the traditional approach to environmental protection, commonly referred to as “command and control.” Under a command-and-control approach, sources of pollution were required to install certain control technology or meet plant-specific emissions reductions across all affected sources. According to critics of this regulatory approach, command-and-control is needlessly costly because it imposes similar reduction requirements on sources that sometimes have very different control costs, rather than concentrating reductions at the sources with the lowest control costs. In addition, sources can comply with the regulation without achieving the actual emissions reductions needed to meet the overall environmental objectives. For example, in some cities that have not attained the standard for ozone emissions at ground level, economic growth can lead to an increased number of sources of ozone. Even if all these sources comply with the regulation and emit relatively low levels of ozone, the overall emissions can be too high.

Title IV offers a different approach for controlling pollution. After setting the overall reductions in emissions to be achieved, the Congress defined each source’s individual emissions limit. These allocations added up to meet a total emissions cap. Sources must install continuous emissions monitors (CEM) and regularly report their actual emissions to EPA. If they violate their emissions limits, they forfeit allowances to cover the excess emissions and pay automatic fines set at several times the estimated average cost of compliance. However, the allowance trading system also rewards utilities that go beyond the law’s requirements by enabling them to earn profits from the sale of their extra allowances. Sources that reduce emissions below their allocations can sell their extra allowances to others that face higher costs to reduce emissions.

According to the legislative history of title IV as described in a Senate Committee report,³ the allowance trading system presented several benefits. First, the flexibility of the allowance system was expected to minimize the overall cost of the program and significantly reduce regional costs of compliance. Second, the allowance system was expected to result in emissions reductions greater than those required or reductions earlier than anticipated, or both. Third, the allowance system would allow cost-effective compliance while accommodating growth in the demand for energy. Fourth, the incentives provided by the market in allowances were

³Three Years Later: Report Card on the 1990 Clean Air Act Amendments, U.S. Senate Committee on Environment and Public Works (Nov. 15, 1993), pp. 71-72.

expected to stimulate innovations in technologies that would reduce emissions and conserve energy.

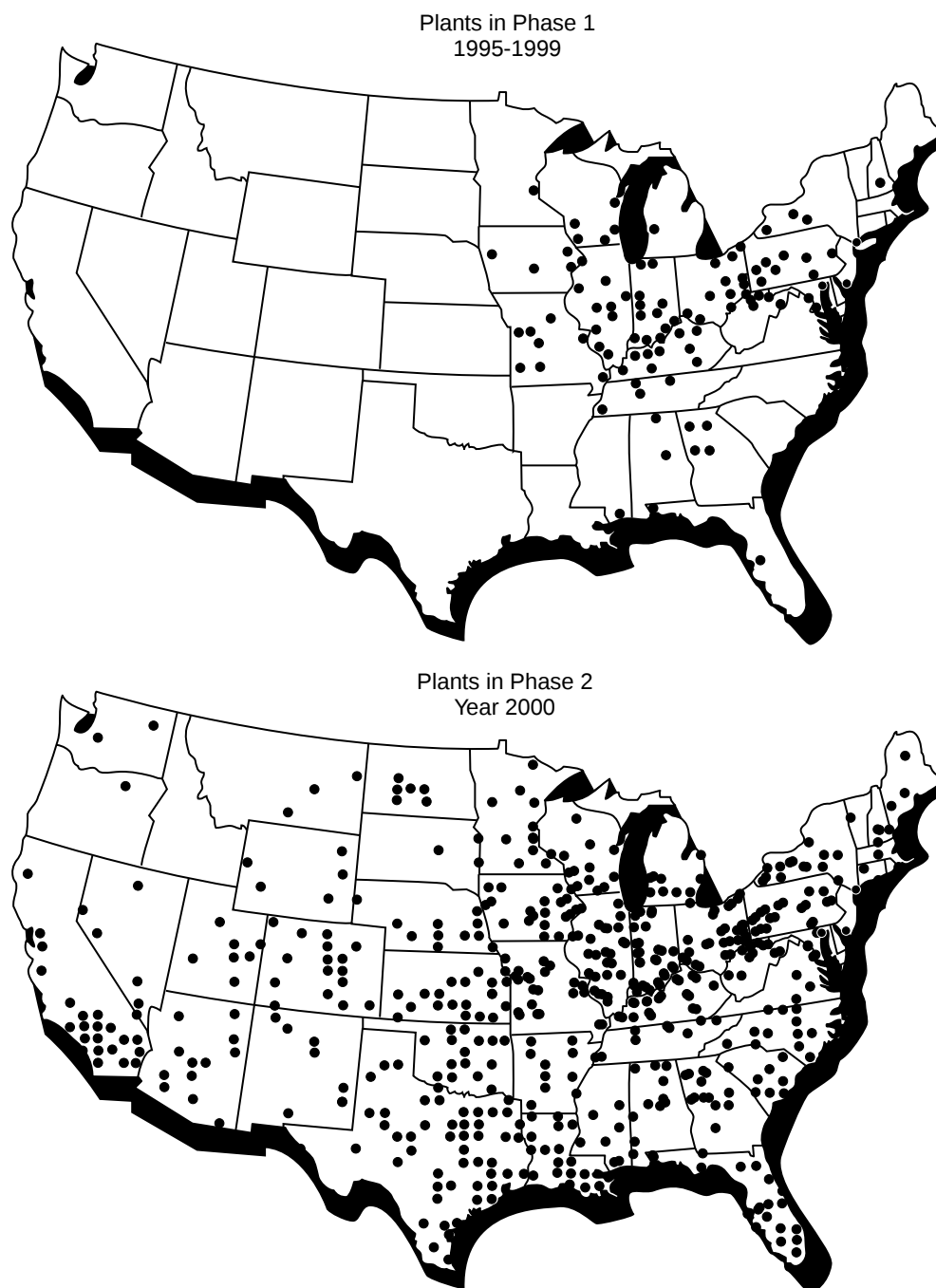
Program's Features Ensure That Environmental Goals Will Be Met

Given the program's design, title IV virtually ensures that the desired amount of emissions reductions will occur, whether or not the emissions trading system functions as expected. The Congress expected the system of marketable allowances to reduce the overall costs of compliance and accommodate growth in the demand for electricity. However, the emissions limits must be met even if the trading system does not function as expected.

Nationwide Emissions Cap

The acid rain control program imposes a nationwide emissions cap, reducing annual SO₂ emissions from utilities by an estimated 8.5 million tons from 1980 levels, beginning January 1, 2000. This reduction is implemented in two phases. Phase 1, beginning January 1, 1995, applies to the 110 highest-emitting utility plants and mandates that annual emissions be reduced by about 3.5 million tons. This phase primarily affects large midwestern coal-fired plants. Phase 2, beginning January 1, 2000, requires an additional annual reduction of about 5 million tons, imposing a nationwide annual emissions cap of 8.95 million tons of SO₂. Phase 2 applies to the Phase 1 plants and virtually all of the approximately 700 remaining utility plants throughout the nation, which are generally cleaner and smaller. Figure 1.3 shows the geographic distribution of the utilities affected in these two phases.

Figure 1.3: Geographic Distribution of Utility Plants Under Phases 1 and 2



Source: GAO's illustration based on EPA's data.

Emissions Allowance System

The program's mechanism for allocating each utility's emissions reductions is an extensive system of permits and emissions allowances. An allowance is a limited authorization to emit a ton of SO₂. Allowances are allocated on the basis of specific formulas contained in the law.⁴ The allowances may be traded or banked for future sale or use. Utilities generally must either reduce emissions or acquire allowances from another utility to make up the shortfall. With certain exceptions, new power plants—those that began operation after title IV's enactment—have to obtain allowances from those already holding allowances. Within the allowance system, incentives are provided for the use of conservation and renewable energy sources and the early use of scrubbers. For example, Phase 1 units that installed scrubbers could have obtained bonus allowances from a reserve of 3.5 million held by EPA. Anyone may trade in allowances—including brokers, environmental groups, and private citizens—and trading can be conducted nationwide with no geographic restrictions. No matter how many allowances a utility holds, it will not be allowed to emit SO₂ levels that violate the national or state health-protection standards for SO₂.

Continuous Emissions Monitoring Equipment

Each utility must install EPA-certified CEM equipment and regularly report its emissions to EPA. This monitoring and reporting requirement ensures that actual emissions are accurately tracked. At the end of the year, EPA grants utilities 30 days to obtain the allowances necessary to cover their actual emissions during the previous year. After this grace period, EPA deducts allowances from a utility's allowance holdings in an amount equal to its recorded emissions. The deduction of allowances, as well as the issuance, transfer, and tracking of allowances, is conducted through EPA's automated allowance tracking system. Operating like a bank, this system tracks the allowances held by utilities and any other companies, organizations, or individuals possessing allowances. The tracking system provides EPA with a way to determine compliance by ensuring that actual emissions do not exceed the available allowances.

Automatic Penalty

Title IV provides that if a utility does not have enough allowances to cover its emissions, it is subject to an automatic penalty of \$2,000 per ton of excess SO₂, indexed yearly to inflation. This amount is several times more than the estimated average cost per ton of reducing SO₂ emissions. A utility

⁴Allowances are allocated to each utility according to its generating capacity and historical emissions during the base period 1985-87. Each combustion unit, or boiler, in a power plant is allocated allowances. A utility can have multiple power plants, and plants can have one or more combustion units.

that does not comply also has its allowance holdings reduced in the next year by one allowance for each excess ton of SO₂ emitted.

Permits and Compliance Plans

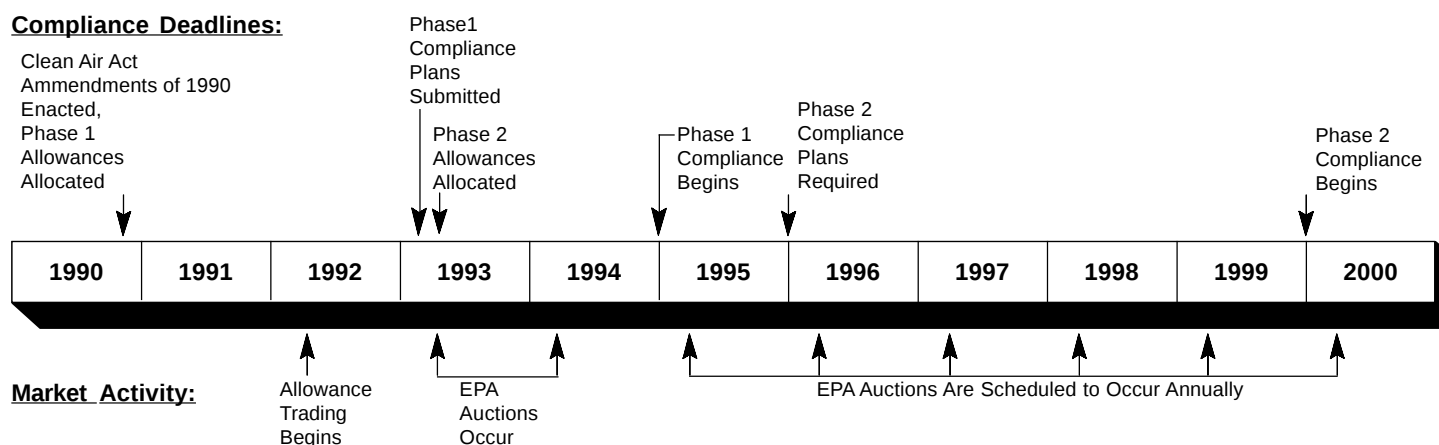
Finally, each utility must file a permit and compliance plan with EPA describing how it will meet its emissions limits. In Phase 1, EPA is responsible for issuing permits and reviewing the utilities' compliance plans; in Phase 2, EPA-approved state or local agencies will issue permits and review the plans. Permit applications and compliance plans for Phase 1 were due on February 15, 1993, and permits and compliance plans for Phase 2 will be required by January 1, 1996. Utilities can reduce emissions by purchasing allowances from other utilities, banking extra allowances for future use, switching from high-sulfur coal to low-sulfur coal or natural gas, installing scrubbers, shifting some electricity production from dirtier plants to cleaner ones, and encouraging more efficient electricity use by customers. Title IV also maintains the authority of state public utility commissions and the Federal Energy Regulatory Commission (FERC) to regulate utilities' electric rates. Generally, state utility commissions regulate all retail transactions of electric power, while FERC has authority over most wholesale transactions, which account for about 10 percent of all the electricity generated.

Trading of Allowances Has Already Begun

Since the passage of the 1990 amendments, EPA has issued rules to implement the program. It also held two allowance auctions intended to stimulate trading.

Many of these rules were required within 18 months of enactment of the legislation. This deadline was tight because the utilities needed time to develop and implement strategies to meet the January 1, 1995, date for complying with Phase 1 requirements. Within 24 months of the statute's enactment, EPA had promulgated all of the major rules governing the SO₂ allowance system, including allowance allocations for over 2,000 Phase 2 utility units, requirements for CEMS, and penalties for noncompliance. Since Phase 1 allowance allocations were listed in title IV, trading was permitted upon passage of the 1990 amendments in November 1990. Figure 1.4 depicts the timetable for trading allowances up through the year 2000.

Figure 1.4: Timetable for Trading Sulfur Dioxide Allowances Through Beginning of Phase 2



To stimulate trading early in the program and ensure the availability of allowances for utilities needing them, title IV required EPA to hold allowance auctions once a year. As mandated by title IV, in both Phase 1 and Phase 2, 2.8 percent of the allowances are withheld from utilities each year for direct sale by EPA and for sale at this auction.⁵ At the auction, EPA initially offers 150,000 allowances for sale; from 1996 to 1999, it will offer 250,000 allowances; thereafter, it will offer 200,000 annually. The first two auctions occurred in March 1993 and 1994.

Anyone can participate in these auctions as a buyer or seller, and private parties selling allowances may specify a minimum sale price.⁶ Under the Clean Air Act, EPA has the authority to delegate the administration of these auctions, and EPA chose the Chicago Board of Trade to administer the auctions until 1996.

⁵Proceeds from the auction are subsequently returned on a pro rata basis to the utilities from which they are withheld. In addition, a separate direct sale of 25,000 allowances is held at a fixed price of \$1,500 each, indexed yearly to inflation. Beginning in Phase 2, 50,000 allowances will be offered annually in this sale. Independent power producers have guaranteed rights to these allowances under certain conditions. To date, no allowances have been sold at these sales; unsold allowances are subsequently offered at the EPA auction.

⁶By statute, EPA does not set a minimum price for its allowances.

Other Emissions Trading Programs Have Been Tried

The use of market approaches to environmental problems is not new.⁷ The concept of the SO₂ allowance trading program grew out of EPA's trading programs for air emissions and lead rights. In addition, after years of failing to meet national air quality goals, several cities and states are considering emissions trading as a way to deal with problems of ground-level ozone, or smog.

EPA introduced limited forms of flexibility in trading emissions into its regulations under the Clean Air Act in the late 1970s. It established certain mechanisms—so-called “bubbles,” offsetting, banking, and netting—for trading air emissions between sources in order to allow flexible or lower-cost compliance with requirements. Under EPA's regulatory scheme, bubbles were created so that adjacent point sources of emissions—for example, several emissions stacks within a single facility—could be managed for compliance purposes as if they were one source. The offset mechanism permitted the siting of new polluting sources or increased pollution at existing sources in areas that did not comply with the ambient air quality standards. Under this mechanism, owners or operators of those sources could offset increased pollution by obtaining reductions in emissions of the same pollutant from other existing sources in the area—usually at a greater than one-to-one ratio. Sources could also “bank” reductions in emissions for later sale or use. Finally, modifications to existing facilities were exempted from requirements for new sources if total emissions did not increase significantly (“netting”).

EPA's lead trading program helped cut down petroleum refiners' costs of compliance with tighter lead standards for gasoline. This program existed from 1982 through 1987. Refiners producing gasoline with less lead than mandated by the stricter standards could sell or bank lead rights. Refiners that incurred higher costs as a result of the tighter standards were able to ease the transition by purchasing lead rights that would allow them to produce gasoline with more lead than they could otherwise have done.

To clean the air while limiting compliance costs, several states and localities are currently considering or implementing market-based approaches to pollution control. For example, Illinois has proposed trading as a way to curb smog in Chicago, and the Northeast Ozone Transport Commission, comprising 12 northeastern and mid-Atlantic states and the District of Columbia, is considering trading for pollutants that cause smog. In addition, the South Coast Air Quality Management

⁷See *A Market Approach To Air Pollution Control Could Reduce Compliance Costs Without Jeopardizing Clean Air Goals* (GAO/PAD-82-15, Mar. 23, 1982).

District, responsible for the city of Los Angeles and the surrounding counties, plans to control smog through a trading program, known as the Regional Clean Air Incentives Market.

After several decades of trying to control its smog, Los Angeles still suffers from the dirtiest air of any urban area in the United States, and pollution must be cut in half to meet federal and state laws on air quality. The Regional Incentives Market program, which the management district adopted in October 1993, requires that overall emissions of two main industrial pollutants, nitrogen oxides and sulfur oxides, be reduced gradually every year. However, facilities may buy and sell emissions rights among themselves, rather than conforming to command-and-control regulation. Nearly 400 businesses in the Los Angeles area are included in this program, and trading has begun, although slowly. Market observers say that trading will probably remain limited until 1996, when tighter emissions limits that are more expensive to achieve increase the demand for emissions rights.

Objectives, Scope, and Methodology

In May 1992, the Chairman of the Environment, Energy, and Natural Resources Subcommittee, House Committee on Government Operations, requested that we review the SO₂ allowance trading program and its potential to curb acid rain at less cost to the nation. On the basis of subsequent discussions with the Chairman's office, we agreed to focus on the following questions:

- What is the extent to which trading is expected to reduce SO₂ emissions and compliance costs, and what is the status of the allowance trading market?
- What are the impediments to increased allowance trading?
- What are the implications for designing a similar approach to curtail carbon dioxide (CO₂) emissions?

To examine the extent to which trading is expected to reduce SO₂ emissions and compliance costs, we contracted with Van Horn Consulting, an economic consulting firm. We did not verify the consultant's calculations because of the confidential nature of the utilities' cost data that the contractor used. However, we discussed the requisite quality control procedures with the team that conducted the analysis. Additional details on the consultant's methodology and results are presented in appendix I.

To evaluate the extent to which trading is expected to reduce SO₂ emissions, the consultant projected annual emissions for power plants located in each state with Phase 1 utilities, using the most recent information available on these utilities' compliance strategies and costs. In addition, we reviewed existing studies by the National Acid Precipitation Assessment Program, ICF Resources, Inc., and the Congressional Research Service to evaluate the probable impact of allowance trading on sensitive regions. We interviewed environmental groups such as the Adirondack Council, the National Resources Defense Council, the Environmental Defense Fund, and the Sierra Club to obtain their views on the program. Using the data on completed trades described below, we mapped the geographic distribution of the trades made to date by state.

To assess the extent to which trading is expected to reduce compliance costs, we examined, based on the results of the contractor's work, the cost reductions resulting from potential trading scenarios at the national, state, and utility levels. We examined data on compliance costs for all the regulated utilities to determine whether sufficient variation in costs exists to warrant trading. After finding that most trading is occurring within utilities rather than between them, the consultant estimated the potential reductions in total costs that would result from increased trading between nonaffiliated utilities. To determine whether trading is reducing the burden in those states where utilities face higher costs of compliance, we estimated the potential cost reductions from trading for each state in the program. Finally, we conducted case studies at utilities that have been trading to evaluate how completed trades have affected their costs.

To determine the status of the allowance trading market, we reviewed all known allowance trades made between utilities through September 1994 and all allowance transactions at the EPA auctions. We monitored EPA's allowance tracking system for trades on the system. For trades not on the system, we interviewed allowance brokers, traders, and market analysts and monitored the electric utility trade press for reports of completed transactions. We analyzed studies on trading prepared by the Electric Power Research Institute, the Department of Energy (DOE), EPA, the National Regulatory Research Institute (NRRI), consulting firms, and environmental groups. We attended industry and regulatory conferences on allowance trading and contacted all utilities believed to have traded allowances to confirm the dates and volume of the transactions.

To learn what factors have impeded trading and identify the implications for designing a similar approach to control CO₂, we conducted case studies

with market participants. For these case studies, we conducted interviews with officials of nine utilities in Illinois, Wisconsin, New York, Georgia, and North Carolina and with each of these states' public utility commission and environmental agencies. In addition, we interviewed officials of EPA, FERC, DOE, and the Internal Revenue Service (IRS). We supplemented the case studies with literature reviews and discussions with emissions trading experts and allowance market observers such as NRRI. We also held extensive discussions with electric utility groups, representatives of the scrubber and coal industries, environmental organizations, market analysts, allowance brokers, and university economists. In addition, we discussed the new Regional Clean Air Incentives Market in Los Angeles, California, with regulatory officials, market observers, and program participants.

We conducted our review between October 1993 and October 1994 in Washington, D.C.; Los Angeles, California; and the five states included in the case studies described above. We performed our work in accordance with generally accepted government auditing standards. We discussed the factual information in the report with the Director and staff of EPA's Acid Rain Division and the Deputy Director and staff of FERC's Office of Electric Power Regulation. Their comments were incorporated where appropriate. As requested, we did not obtain written agency comments on a draft of this report.

Utilities Are Reducing Sulfur Dioxide Emissions at Lower Costs but Have Been Reluctant to Trade Allowances

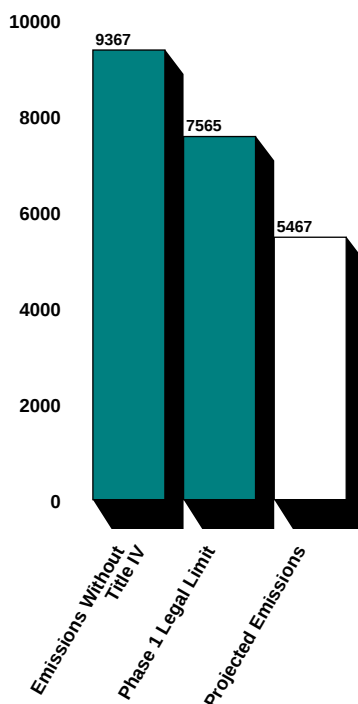
Many utilities are taking advantage of falling compliance costs to reduce SO₂ emissions below the mandated Phase 1 limits. Costs are falling as a result of competition between compliance options spurred by title IV's flexible regulatory approach. Many Phase 1 utilities plan to reduce emissions below allowed levels and, for now, save the surplus allowances for future compliance. Some utilities could reduce their compliance costs even further by purchasing allowances, but few have done so. As a result, the allowance trading market is struggling to develop. Uncertainty among utilities about the price at which they should buy or sell allowances has compounded their reluctance to trade. On the basis of the estimated differences in the costs of reducing SO₂ at electric power plants, trading between utilities could result in substantial cost savings in the future. In addition, these estimates suggest that many states facing higher compliance costs could benefit from the cost reductions possible from more trading.

Sulfur Dioxide Emissions Are Expected to Fall Below Clean Air Act's Limits in Phase 1

According to our consultant's estimates, by 1997 annual SO₂ emissions will be nearly 30 percent less than the Phase 1 annual allowance allocations set by the Clean Air Act. As noted in chapter 1, Phase 1 begins January 1, 1995, and applies to 110 power plants. Many utilities currently plan to save most of these extra emissions reductions as "surplus" allowances for use during Phase 2, beginning January 1, 2000. Figure 2.1 compares the projected annual emissions in Phase 1 with the emissions that would have occurred in the absence of title IV and with the mandated limits.

Figure 2.1: Projected Annual
Emissions in Phase 1

Annual Emissions, in Thousands of Tons



Note: Data are 1997 projections for Phase 1 units only.

Title IV allows utilities to save surplus allowances for future use or sale. Utilities' decisions to reduce SO_2 more than required in Phase 1 are based on estimates that curtailing SO_2 emissions is less costly in Phase 1 than it will be in Phase 2.¹ "Banking" the surplus provides firms with further flexibility. Firms that expect to install costly scrubbers in Phase 2 can delay installation a few years by using their surplus allowances from Phase 1 to comply. Others expect to sell their surplus at higher allowance prices in Phase 2 than in Phase 1. Utilities will use most of the allowances freed up by these extra emissions reductions early in Phase 2, according to an industry projection.

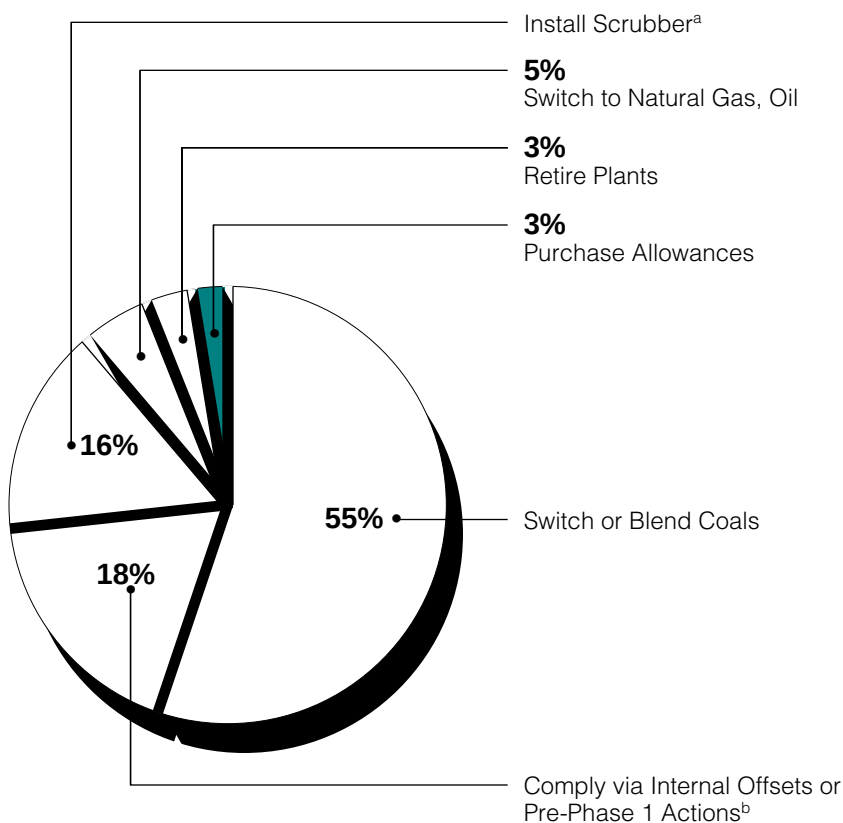
¹Phase 1 limits utilities' emissions to 2.5 pounds of SO_2 per million BTUs (British thermal units) of heat consumption. Phase 2 cuts the emissions rate to 1.2 pounds of SO_2 . Because the costs of reducing emissions tend to rise for each extra pound of SO_2 abated at a facility, meeting Phase 1 limits is less expensive per pound than meeting Phase 2 limits.

Costs Are Falling as Utilities Take Advantage of More Compliance Choices

Utilities are taking advantage of their flexibility under title IV of the Clean Air Act to choose less costly ways to reduce emissions. As described in chapter 1, utilities may now switch to low-sulfur coal, retire an old plant, purchase allowances from other utilities, or install a scrubber, among other options. This gives utilities the flexibility to choose the cheapest measure. A utility system may also lower costs through internal trading, cutting back emissions in one power plant and using the resulting allowances to cover emissions in another plant. The utilities' ability to choose among various compliance measures is resulting in lower prices for low-sulfur coal, scrubbers, and allowances as vendors compete to fulfill utilities' compliance needs.

Phase 1 utilities are selecting a variety of measures to reduce SO₂. However, few are purchasing allowances as their primary means of compliance despite evidence that purchasing allowances could reduce their compliance costs. For instance, on the basis of the estimated costs of reducing SO₂ at their electric power plants, many Phase 1 utilities face costs significantly higher than current allowance prices. (See app. I, fig. I.1.) As shown in figure 2.2, 55 percent of Phase 1 plants plan to switch to low-sulfur coal and 16 percent intend to install scrubbers, but only 3 percent expect to purchase allowances. Only one utility has bought allowances as its primary means of compliance. Others plan to transfer allowances internally; that is, they will use surplus allowances generated by their units with lower costs of reducing emissions to offset emissions from their units with higher costs of pollution abatement.

Figure 2.2: Options Selected for Phase 1 Compliance



^aFour plants are both switching coals and building scrubbers.

^bCompliance is achieved by overcompliance in another unit, or the plant was already in compliance before Phase 1 began.

Source: NRRI's analysis of data from the Electric Power Research Institute.

The flexibility to choose different measures to reduce pollution is leading to greater competition among the options. For instance, according to ICF Resources, Inc., in 1990 most analysts projected prices for low-sulfur coal to reach \$40 per ton by 1995.² Currently, prices are less than \$25. Scrubber vendors also report falling prices, up to 50 percent since 1990. Allowance prices, which reflect the falling costs of using low-sulfur coal and

²This estimate is for central Appalachian compliance coal, an industry benchmark. ICF Resources, Inc., is a consulting firm.

scrubbers, are also much lower than predicted. As discussed below, additional factors may be affecting allowance prices.

Before the passage of the Clean Air Act Amendments of 1990, scrubber vendors expected 35 to 40 scrubber contracts in Phase 1. With utilities' newly acquired flexibility to choose from among competing options, vendors now expect only 13 to 14 scrubber contracts.³ For example, Illinois Power canceled scrubber construction in progress and purchased allowances to meet the lower SO₂ limits. Industry officials also expect fewer scrubbers in Phase 2 because of surplus allowances carried over from Phase 1. Two southeastern utilities, Carolina Power and Light and Duke Power, are purchasing allowances to postpone or eliminate the need for scrubbers in Phase 2. State public utility commissions and utilities we visited stated that other firms have purchased allowances and switched to low-sulfur coal to avoid the added cost of building and operating scrubbers. In response to this decreasing demand for their product, scrubber vendors have introduced innovations to reduce costs, such as larger absorbers, new anticorrosive materials, and processes to eliminate waste streams from scrubbers by converting them into marketable products. The higher SO₂ removal rates of some scrubbers will result in overcompliance and extra allowances for sale, further reducing net costs. To lower utilities' costs, one company is offering to operate and maintain the scrubbers that it sells to utilities, charging a specified fee per ton of SO₂ removed.

The market for low-sulfur coal is getting larger as a result of title IV. Low-sulfur western coal is penetrating midwestern and eastern markets in large quantities. For instance, Georgia Power is purchasing Powder River Basin coal from Wyoming. Railroads have increased their capacity to meet the resulting increased demand for transportation of western coal. In addition, eastern low-sulfur coal is being supplied at lower prices than anticipated as a result of increased mining productivity, lower rail rates, and competition from western coals.

Most Utilities Have Yet to Trade With Other Firms

Although reducing SO₂ emissions costs much more at some utilities than at others, few of the utilities with higher abatement costs have purchased allowances from those with a surplus to avoid incurring these higher costs. Utilities are uncertain about the price at which to buy or sell allowances because of limited and conflicting price information. Few trades have occurred, and most trades are now occurring around the time

³A contract may include one or more scrubber units.

of the annual EPA auctions. While these auctions are providing some information about allowance prices, these prices have been much lower than most analysts predicted and generally lower than the prices of the allowances traded between utilities.

Few Utilities Are Buying Allowances Despite Potential Cost Savings

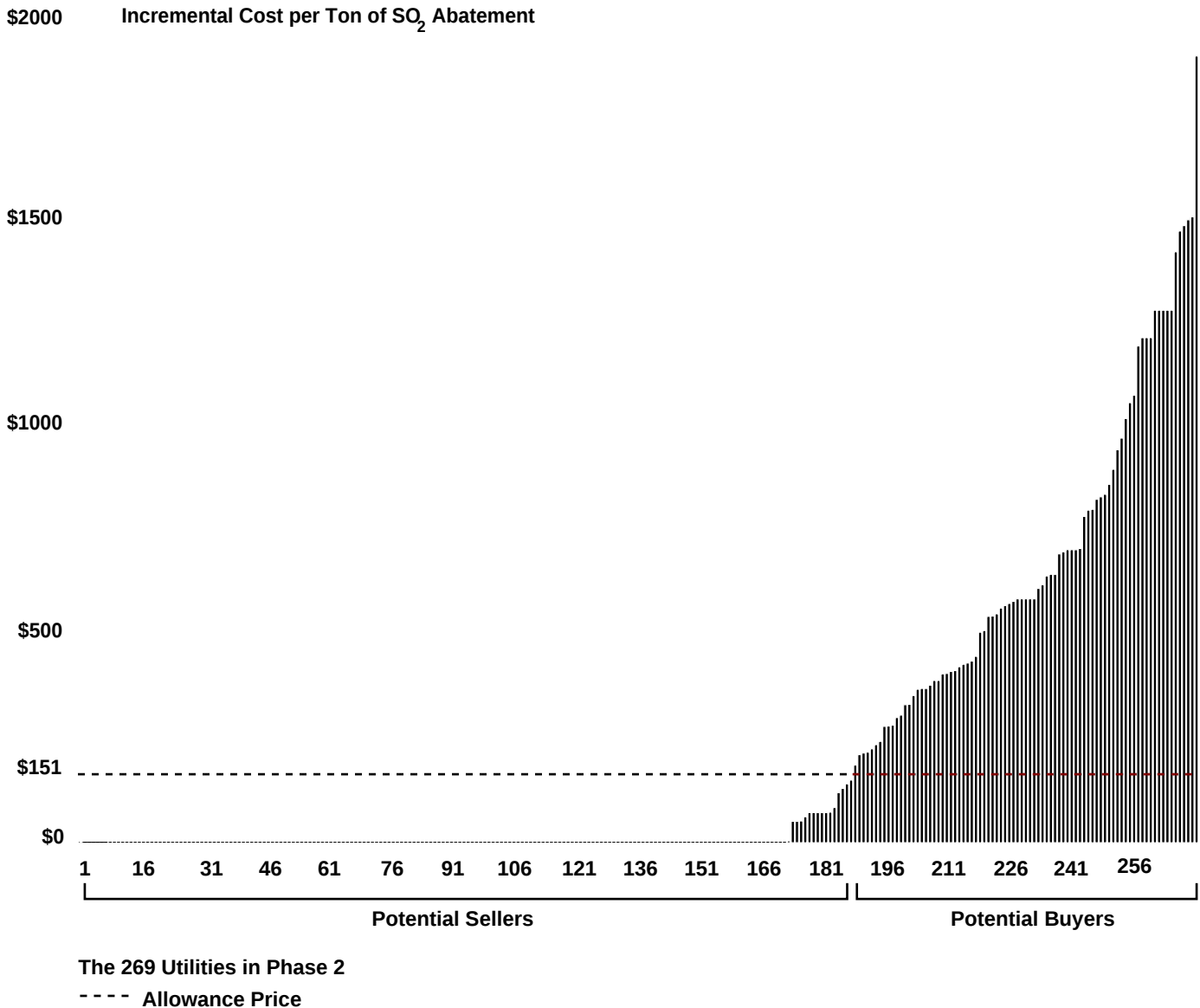
Few utilities are purchasing allowances from other utilities as a compliance strategy, even though potentially large savings are possible. Most of the utilities that can avoid higher abatement costs by purchasing allowances from other firms have not done so. Of 269 utilities that could be trading, only 12 have bought more than 5,000 allowances from another utility. Two firms—Illinois Power and Carolina Power and Light—are responsible for 61 percent of the allowances purchased by utilities from other firms.

Figure 2.3 suggests that many utilities could avoid higher compliance costs by buying allowances from other firms. This figure presents the estimated incremental costs per ton of SO₂ abated for each of the 269 utilities planning compliance strategies for Phase 2.⁴ For instance, approximately 80 utilities—30 percent of the total—have estimated incremental compliance costs above the current allowance price.⁵

⁴The incremental cost is the cost of reducing a ton of SO₂ using the last abatement option required to attain compliance.

⁵Since utilities have already largely determined which compliance measures they will use to meet Phase 1 emissions limits, additional trading is likely to take place to meet Phase 2 limits.

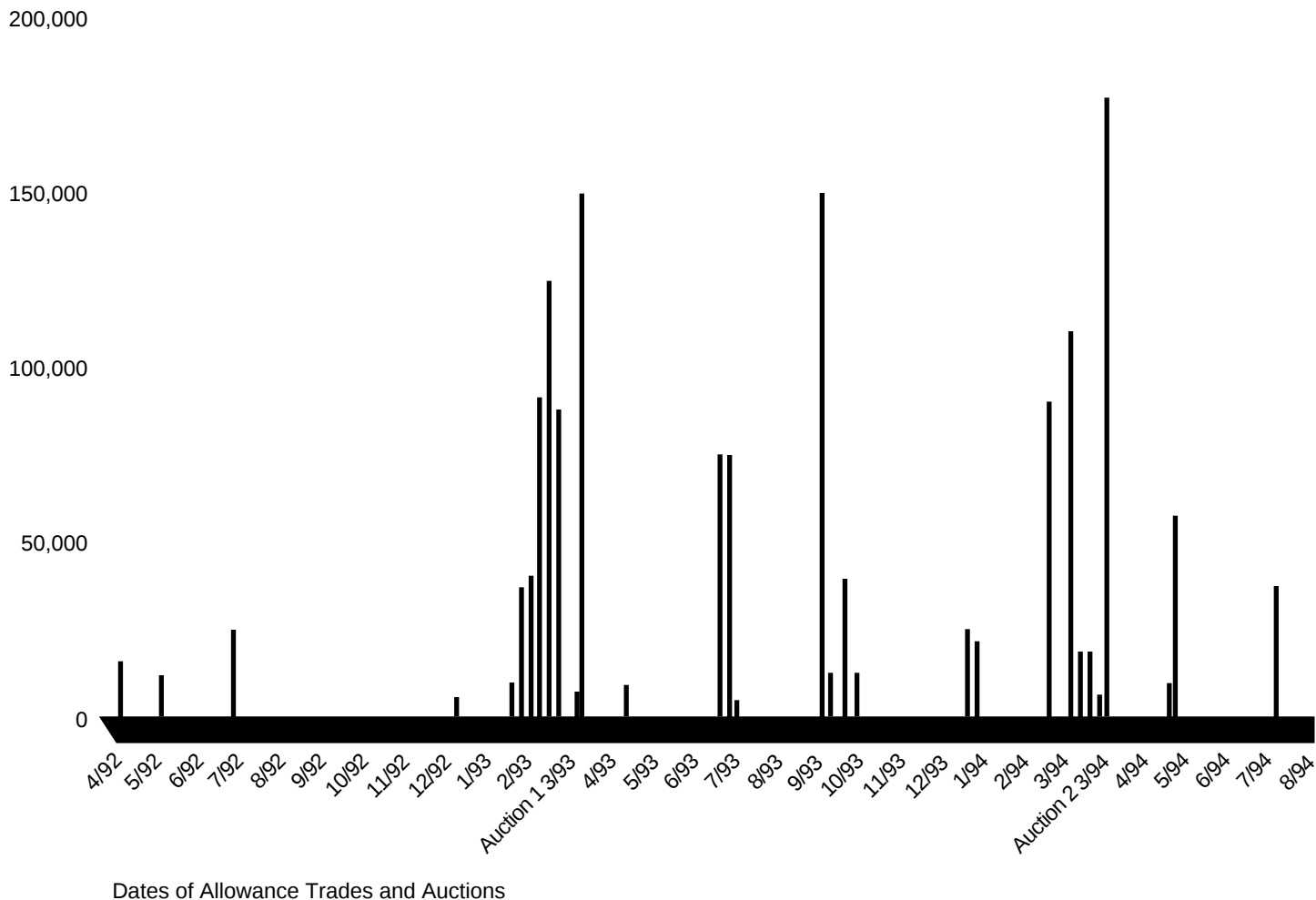
Figure 2.3: Estimated Costs of Abatement Compared With Allowance Price for Utilities in Phase 2



Note: 170 potential sellers have incremental costs at or near zero. Costs are estimated for the year 2002, assuming no interutility trading, and are in 1992 dollars per ton.

Figure 2.4 shows the dates and sizes of trades that have occurred since trading began. Utilities and brokers we interviewed stated that expectations of lower prices at EPA auctions cause more trading near the auctions and few otherwise. For instance, in the period surrounding the last auction, seven trades occurred for approximately 312,000 allowances. Since that time, only one trade has occurred. In total, only 21 trades of 5,000 allowances or more have occurred between utilities.

Figure 2.4: Allowance Trading to Date
Allowances per Trade



Note: Includes interutility trades and sales to brokers and nonutilities. Does not include utilities' internal trades.

In trades that we analyzed in our case studies, utilities projected large cost savings. For example, Central Illinois Public Service stated that it will save \$225 million as a result of allowance trading combined with title IV's flexibility to choose other control options. Illinois Power has reported

saving \$91 million by purchasing allowances instead of installing scrubbers. Similarly, Duke Power projects saving \$300 million, and Wisconsin Electric Power Company estimates saving almost \$90 million by avoiding the installation of scrubbers. Carolina Power and Light expects to reduce its future compliance costs by two-thirds as a result of purchasing allowances.

**Scarce Price Information
and Lower-Than-Expected
Auction Prices Create
Market Uncertainty**

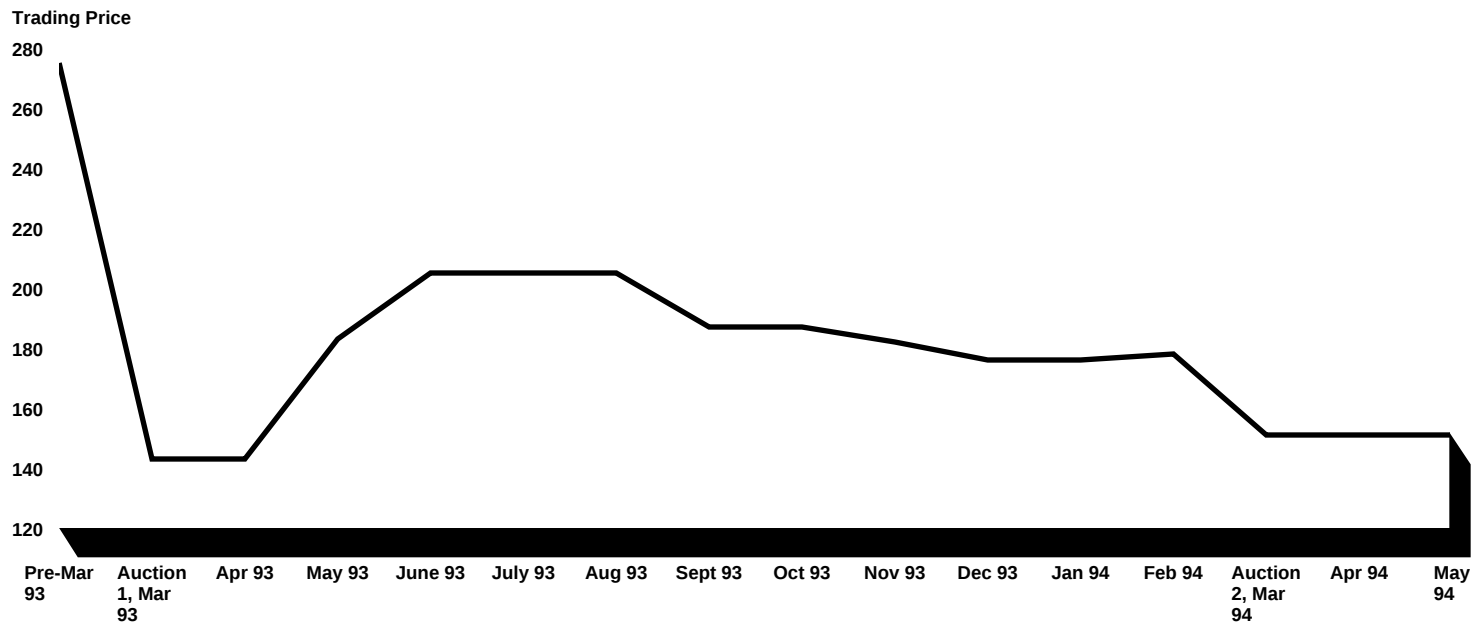
Because few trades have occurred, the amount of reliable information on allowance prices has been limited.⁶ Compounding this problem is the fact that prices on trades completed outside of EPA's auctions have often been withheld from the public. EPA's auctions are intended to accelerate the transition to a "liquid" market—one in which there are many transactions. Such a market provides the most reliable data on the market price of a commodity. However, the two EPA auctions held to date have resulted in allowance prices that were lower than most analysts predicted and lower than the prices of trades between utilities. The result is continuing uncertainty among utilities as to what the allowance price should be.⁷

Prices are determined by trades between firms and by the results of the EPA auctions. As figure 2.5 shows, allowance prices have varied considerably thus far. Higher prices set by trades between firms have been followed by lower prices at each of the two EPA auctions. Prices have also been lower than EPA projected in 1990. As figure 2.6 indicates, EPA auction prices are lower than utilities might have expected on the basis of price information available earlier in the program.

⁶This lack of price information is typical for a "thin" market—one with few transactions.

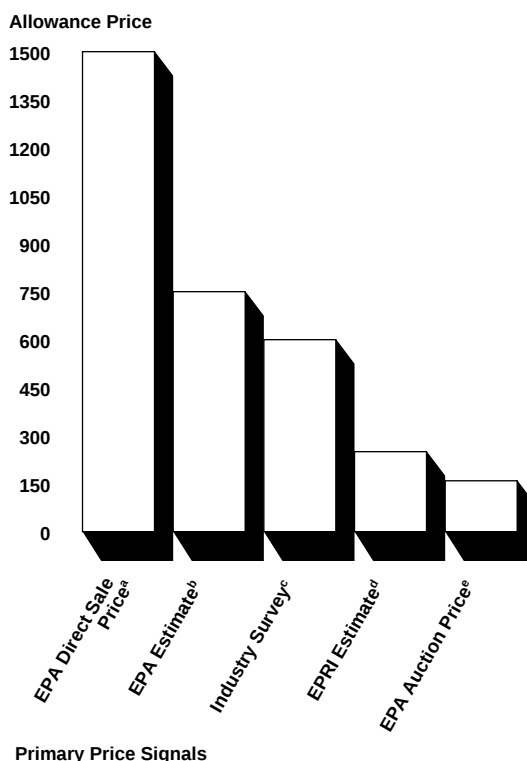
⁷In contrast, utilities can readily obtain the current market price of a scrubber or a ton of low-sulfur coal.

Figure 2.5: Trading Price of Allowances



Source: GAO's illustration based on data from the TERRA Group, Washington, D.C.

Figure 2.6: Allowance Prices and Estimates



^aAs noted in chapter 1, the Clean Air Act requires EPA to offer allowances for direct sale at \$1,500, indexed to inflation.

^bEPA estimated the incremental cost of allowances to be approximately one-half of the direct sale price when trading began.

^cAERX Survey of Utilities.

^dIntegrated Analysis of Fuel, Technology, and Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990, Electric Power Research Institute (EPRI), TR-102510 (Aug. 1993), pp. 5-11, 5-13.

^eThe average winning bids at EPA's two auctions were \$156 (1993) and \$159 (1994).

Our discussions with utility officials and market analysts revealed that buyers and sellers differ widely on what the market price should be. Many believe this difference is largely the result of the design of EPA's auction, which is discussed in chapter 3 of this report. Apparently, many potential buyers are reluctant to pay more than the auction price, while most potential sellers are unwilling to accept the auction price. In fact, less than one-half of 1 percent of allowances offered by private sellers at EPA's two

auctions were sold, as shown in table 2.1. Private sellers—mostly utilities—expect higher prices.

Table 2.1: Allowances Sold by Private Sellers and EPA at the Two Auctions

	Private sellers	EPA
Allowances offered	280,511	325,000
Price range of offers	\$10 - \$1,900	No minimum price
Number sold	1,210	325,000
Percentage of total sold	0.43	100

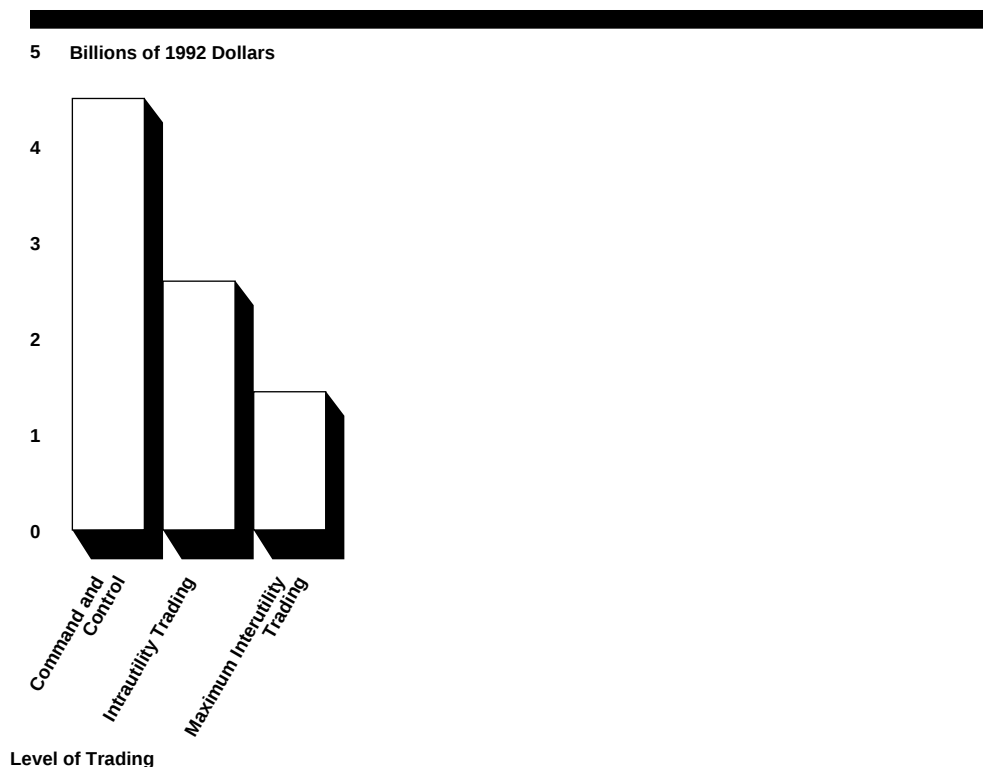
More Trading Could Reduce the Costs of Meeting Sulfur Dioxide Mandates

Projected cost savings depend on the level of trading. In 1992, EPA estimated that the costs of achieving compliance would be up to 50 percent lower than the costs under command and control, depending on how much trading occurred between utilities. Since then, the Electric Power Research Institute has estimated that compliance costs could fall by up to 57 percent. More recent modeling estimates made by our consultant suggest similar possible savings in Phase 2. According to these estimates, for the year 2002, Phase 2 emissions reductions would cost as much as \$4.5 billion per year if utilities were forced to use the types of controls typically prescribed under more traditional regulation. Instead, under title IV's more flexible approach, utilities are estimated to spend about \$2.6 billion per year if they restrict themselves to internal trading. Costs are estimated to fall as low as \$1.4 billion per year if utilities trade with one another until all cost savings opportunities are realized.

Most utilities are planning to trade their allowances internally to reduce compliance costs, and it seems likely that title IV's regulatory flexibility will lead to substantial cost savings. However, as shown in figure 2.7, based on estimates for the year 2002, another \$1.2 billion per year in estimated savings could be possible if maximum interutility trading occurs.⁸

⁸Similarly, our consultant estimated annual cost savings of nearly \$1.1 billion for the year 2009 if utilities move from internal trading to maximum interutility trading.

Figure 2.7: Estimated Annual Cost of Compliance Under Three Trading Scenarios



Note: Costs are estimated for 2002.

More Trading Could Result in Greater Cost Savings for States

Modeling done for GAO suggests that utilities in some states could reduce compliance costs through greater interutility trading. For example, with interutility trading, estimated Phase 2 compliance costs of Pennsylvania plants could be as much as \$135 million lower in the year 2002 than if these plants relied on internal trading alone. Similarly, estimated costs for utility plants in Indiana and New York could be reduced by over \$75 million. Table 2.2 shows which states could benefit most from interutility trading in the year 2002. The estimated cost savings in table 2.2 can occur if utilities with higher estimated costs of reducing SO₂ purchase allowances from utilities with lower estimated costs.⁹ A complete list of the states' costs and potential savings from trading appears in appendix I.

⁹These state estimates assume a national market-clearing price of \$317 per ton.

Table 2.2: States' Estimated Costs and Potential Savings From Trading in the Year 2002

Millions of 1992 dollars			
State	Costs with internal trading	Costs with interutility trading	Potential savings
Pennsylvania	\$270	\$135	\$135
Indiana	319	235	84
New York	32	(46) ^a	78
Florida	135	75	60
Delaware, New Jersey, Maryland, District of Columbia ^b	114	56	58
Illinois	182	132	50
Wisconsin	2	(48) ^a	50
Alabama	127	78	49
North Carolina	107	62	45
Louisiana, Mississippi ^b	59	14	45

Note: Electricity rates in each state may not necessarily be affected as shown because utility service territories cross state boundaries.

^aParentheses indicate opportunities for states to sell enough allowances to offset their costs and make a net profit.

^bStates with few utilities have been aggregated.

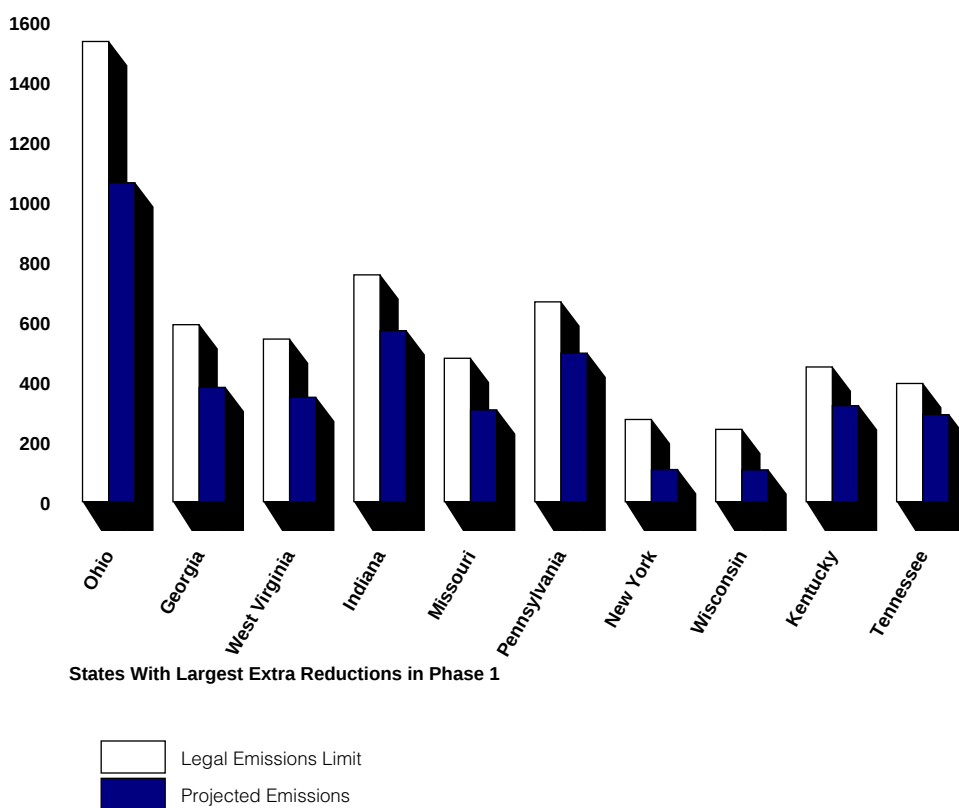
Extra Emissions Reductions in Phase 1 May Benefit Environmentally Sensitive Areas

Our modeling for Phase 1 and analysis of the trades to date suggest that utilities' responses to trading could benefit environmentally sensitive areas in the Northeast. Our projections show that utilities in Phase 1 will reduce SO₂ emissions approximately 2 million tons below annual allowance allocations. In addition, utilities in Ohio, which has the highest emissions of all Phase 1 states, are projected to emit 31 percent less SO₂ than their Phase 1 allocations.¹⁰ Figure 2.8 shows the 10 states with the largest projected extra reductions in tons per year. (See app. I, table I.3, for a complete list of the states' expected reductions in Phase 1.)

¹⁰Power plants in the Ohio Valley, Appalachia, and the Midwest are major sources of SO₂ emissions that may contribute to acid rain in the Northeast.

**Figure 2.8: States With Largest
Projected Extra Emissions Reductions
in Phase 1**

Annual Emissions in Thousands of Tons



Studies on the environmental impact of trading by ICF Resources, Inc., the National Acid Precipitation Assessment Program, and the Congressional Research Service suggest that interutility trading should encourage some midwestern states to be net sellers of allowances.¹¹ Midwestern utilities were considered the most likely to install scrubbers because of their low cost per ton of SO₂ removal.¹² Utilities we contacted believe that regions with higher per-ton scrubbing costs and higher projected growth in electricity demand, such as the Southeast, would be net buyers of

¹¹1990 Integrated Assessment Report, NAPAP (Washington, D.C.: Jan. 1990); Economic Analysis of Title V (Acid Rain Provisions) of the Administration's Proposed Clean Air Act Amendments (H.R. 3030/S. 1490), Prepared for EPA by ICF Resources, Inc. (Fairfax, Va.: Sept. 1989); Acid Rain Control: An Analysis of Title IV of S. 1630, CRS (Washington, D.C.: Jan. 31, 1990).

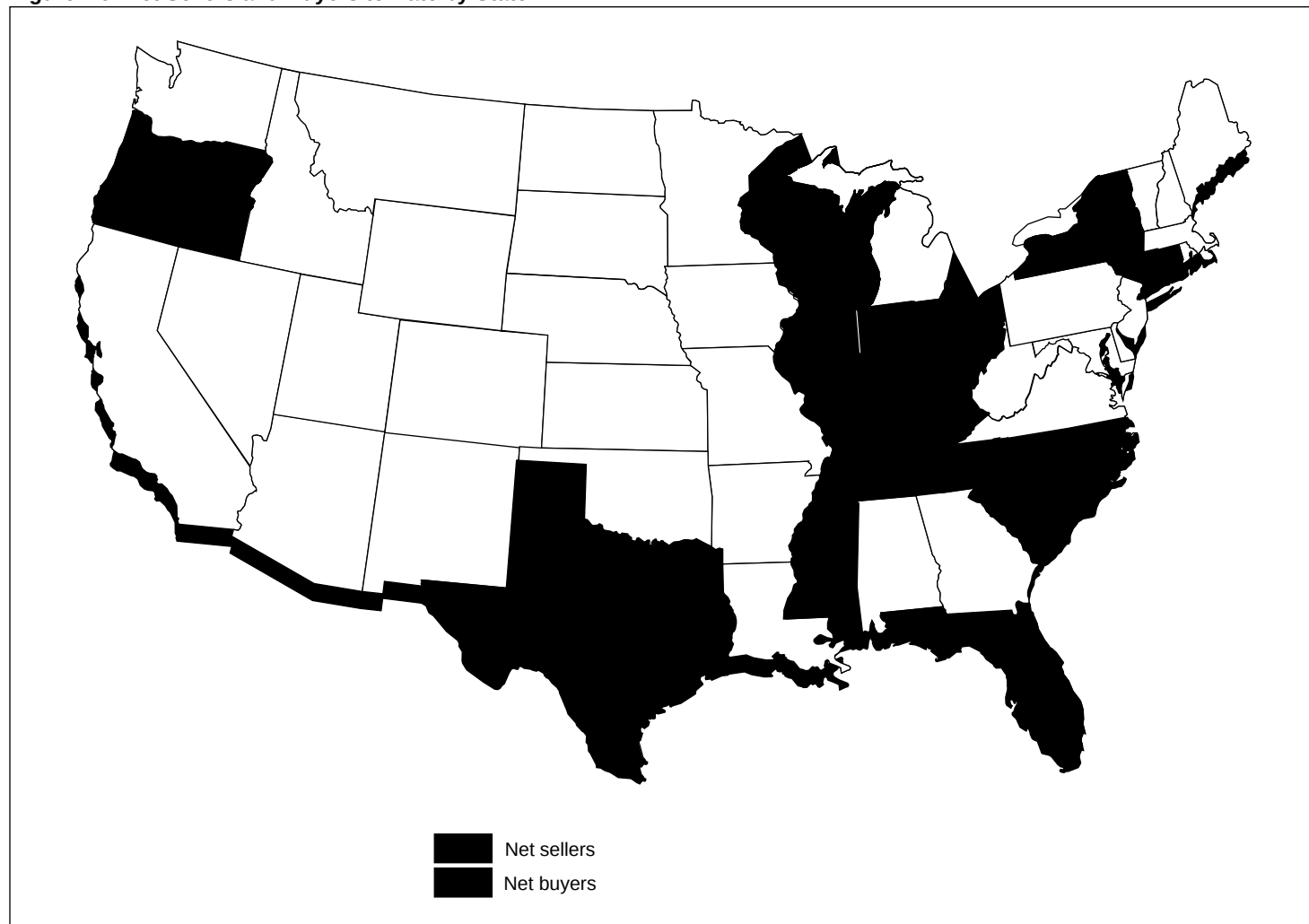
¹²This occurs because the cost per ton of removing SO₂ is lower for a plant burning high-sulfur coal than for a plant burning low-sulfur coal. Midwestern utilities typically burn high-sulfur coal.

allowances. This is consistent with EPA's 1993 base case forecast of emissions by state through the year 2010.¹³

In most cases, as shown in figure 2.9, trades to date appear to support projections that midwestern states will be net sellers and southeastern states net buyers of allowances. Although too few trades have occurred for these data to be conclusive, net sellers have been western, midwestern, and northeastern states. Net buyers have been mostly southeastern states, with the exceptions of Indiana and Illinois. However, allowances are financial assets as well as compliance tools. Purchases may be occurring for various reasons, and current purchases will not necessarily result in future emissions by the buyer. For example, coal suppliers and allowance brokers will probably sell or trade their allowances in the future, and some utilities buying at current low prices may sell them in the future at projected higher prices.

¹³Economic Analysis of The Title IV Requirements of The 1990 Clean Air Act Amendments, prepared for EPA by ICF Resources, Inc. (Fairfax, Va.: Feb. 1994), p. A-3.

Figure 2.9: Net Sellers and Buyers to Date by State



Reluctance to Trade Has Been Due to Various Regulatory, Industry, and Market Factors

Several factors are causing the low level of allowance trading cited in chapter 2. First, phasing in the trading program separated two groups of utilities that might have traded sooner. A second barrier to more trading results from the economic regulation of electric utilities. State public utility commissions and FERC regulate utilities' profitability and recovery of costs, but to date, the commissions have provided limited regulatory guidance on allowances. Without this guidance, many utilities may avoid trading and instead install scrubbers or fuel-switching equipment because the costs for such items are traditionally recouped in utility rates, while the question of whether utilities can recover allowance trading costs remains unresolved. As a result of increased competition in the electric power industry, some utilities and regulators are disposed to trading, but for many others, trading represents a major change from traditional regulation to a more flexible market approach.

In addition to the trading program's structure and the regulatory system, five other factors have been cited by market participants as impeding trading, although the magnitudes of the effects of these factors are unknown. They include problems with the program's auction design, uncertainty regarding EPA's future regulations, possible state restrictions on trading because of lingering environmental concerns, state mandates on coal use, and the Internal Revenue Service's (IRS) tax treatment of allowances.

Phasing in the New Program Has Slowed Market Development

The structure of the allowance market has slowed trading. As noted, in Phase 1 only about 14 percent of the affected power plants in the country are required to reduce emissions; hundreds of other plants are not added to the program until Phase 2, beginning in the year 2000. With limited participation required in Phase 1, the market has not developed rapidly. According to some environmental groups and market participants, the decision to include such a small percentage of the nation's utility plants in Phase 1 meant that trading would begin quite slowly. In addition, 3.5 million allowances were awarded to certain utilities in Phase 1, reducing their need to trade now.

As noted in chapter 1, Phase 1 only applies to the 110 utility plants with the highest levels of emissions, while Phase 2 broadens the program to include over 700 of the cleaner, usually smaller plants. The utilities in Phase 1 generally have lower emissions reduction costs per ton of SO₂ reduced than those added in Phase 2, making them more likely sellers and the Phase 2 utilities more likely buyers. As discussed in chapter 2, many

Phase 1 utilities are projected to surpass their reduction requirements and will have extra allowances for potential sale. On the other hand, the cleaner, smaller utilities added in Phase 2 must reduce emissions by a relatively small amount to be in compliance. Nevertheless, many of these plants are already burning low-sulfur fuel, and additional pollution controls could be costly for the amount of emissions to be reduced. Thus, a cost-effective compliance strategy for many utilities only subject to Phase 2 may be to purchase allowances from Phase 1 utilities that surpassed their reduction requirements and generated extra allowances.

However, the two-step phase-in of emissions reductions created a multiyear gulf between the time that these probable sellers and buyers had to make decisions on compliance strategies. Utilities might have traded allowances sooner if they had all been required to meet a uniform emissions reduction at the same time. Instead, compliance plans for utilities in Phase 1 had to be submitted to EPA by February 15, 1993—less than 4 months after most rules for the program were finalized. Phase 2 utilities do not have to submit their compliance plans until January 1, 1996, and compliance does not begin until 2000. Few Phase 2 utilities, the market's "buyers," have traded allowances; this low level of trading may be due in part to the fact that their deadlines are far in the future. According to EPA and some market observers, the effectiveness of trading cannot be judged until Phase 2, when all affected utilities must comply with the requirements.

One allowance broker noted that a related market development problem has arisen because Phase 1 utilities submitted their compliance plans on the basis of sparse information on allowance prices: In the absence of an active SO₂ allowance market, only price projections were available. As noted in chapter 2, the actual market price of allowances has been considerably less than projections indicated earlier in the program. As a result, some utilities may have adopted compliance strategies in Phase 1 that avoided the use of allowances but were more expensive than necessary.

The 3.5 million extra allowances awarded to certain Phase 1 utilities that installed scrubbers may also explain why many of these utilities have an allowance surplus and are under little pressure to trade. Worth over \$500 million, these extra allowances in essence subsidized scrubbers—regardless of whether they were the least-cost compliance strategy. For example, one midwestern utility originally planned to switch one of its plants to lower-sulfur coals but then decided to install a

scrubber under pressure from the state public utility commission and because of the availability of 750,000 free allowances.

Regulation of Electric Utilities Has Not Encouraged Trading

A number of market analysts have also suggested that the market's slow development is inherent in the nature of the electric utility industry. That is, market-based compliance is new for utilities, requiring them to adjust to a different culture and regulatory approach. For example, a former public utility commission chairman said the following:

The allowance trading system imposed a market-based environmental compliance mechanism on an industry which has long been tightly regulated, strongly averse to risk-taking, for the most part very conservative, and which has long experienced environmental compliance as simply a matter of unit-by-unit command-and-control.¹

State public utility commissions influence a utility's investment decisions through regulations governing, among other things, acceptable rates of return, recoverable costs, and the distribution of financial risks and returns between ratepayers and shareholders. In the absence of regulatory guidance on SO₂ allowance trading, this system of economic regulation reduces a utility's financial incentive to trade. Another aspect of this economic regulation is the risk-averse nature of the industry, which utilities and market observers say discourages electric power companies from trading allowances with one another.

Regulatory Treatment of SO₂ Allowances Is Uncertain

Most state utility commissions lack regulations on allowance trading and the distribution of any resulting gains or losses between ratepayers and shareholders. Under traditional regulation, utilities are allowed a rate of return on capital investments and recovery of their operating expenses. Ratepayers—consumers—pay for these costs through electricity rates. Since passage of the Clean Air Act Amendments of 1990, according to data compiled by the National Regulatory Research Institute (NRRI) and EPA, only 8 of 21 states with utilities subject to Phase 1 have issued rules on the regulatory treatment of allowance transactions, and two states with only Phase 2 utilities have issued guidance. In general, states have addressed utilities' compliance costs and allowance trades on a case-by-case basis. According to a former chairman of a public utility commission, many utilities have waited for signals from their commissions as to how to

¹Hearing on Implementation of Title IV of the Clean Air Act Before the Subcommittee on Air and Nuclear Regulation of the Senate Committee on Environment and Public Works, 103rd Cong., 1st Sess., Oct. 21, 1993, statement of Ashley Brown, Harvard Electricity Policy Group, John F. Kennedy School of Government, Harvard University, p. 2.

proceed. But as he noted, the commissions, more accustomed to a role of passive ratemaking, have usually not signaled their intentions.

Without regulatory direction on allowance trading, many utilities may continue to use other compliance options, such as investments in scrubbers or other fuels, whose costs historically have been approved by state commissions, even though allowances might cost less. Given that issues of cost recovery and rate of return are well established for the costs of scrubbers or switching fuels, many utilities may opt for those choices rather than risk incurring the full cost of an allowance transaction before knowing how commissions will act. As noted in chapter 2, 71 percent of the utilities subject to Phase 1 are complying by switching fuels or scrubbing, while only 3 percent are purchasing allowances. In addition, many Phase 1 utilities are banking allowances for their needs in Phase 2 rather than trading with others.

In most states with guidelines on allowances, according to NRRI, gains from trading are to be distributed to the ratepayer only, which may reduce the utility's incentive to trade. In order to sell extra allowances for a profit, utilities generally must reduce emissions more than they are required to. The state commissions will generally distribute any utility profits from trading to the ratepayer. Similarly, if trading turns out to be less cost-effective than other compliance choices, the commissions may make the shareholders pay. In short, any risk remains with the shareholders and any profits remain with the ratepayers. This asymmetric treatment of risks and rewards may reduce any incentive that utilities might have to reduce emissions more than required and offer the resulting allowances for sale.

Traditional Regulation Encourages Utilities' Aversion to Risk

Historically, public utility commissions have insulated utilities from competition, discouraging them from activities perceived as risky. Electric utilities have been provided with a rate of return without the challenges faced in a competitive market like the SO₂ allowance market, where a company's choices, initiative, and flexibility determine profits and losses. According to several utility officials, a utility may avoid the risk of the SO₂ allowance market in favor of compliance options customarily accepted by commissions and incorporated into rates.

While ratepayers pay for a utility's capital investments and operating costs under traditional rate-of-return regulation, most commissions also apply a "prudent investment" test, which holds that a utility's dishonest, wasteful, or imprudent costs may not be included in rate calculations. Over the past

two decades, utilities' efforts to include certain costs in the rate base have been increasingly denied or delayed. As a result, utilities traditionally avoid novel and untried activities—such as allowance trading—that risk being denied recovery in rates. According to an Argonne National Laboratory study of Phase 1 compliance choices,² utilities will tend to avoid compliance options that do not earn a rate of return, even though such options may be less costly. Electric utilities have been referred to as “risk averse,” prone to take least-risk approaches rather than least-cost approaches to problems.

In exchange for the flexibility of allowance trading, utilities are exposed to risks they did not face when specific technologies or emissions standards were mandated. For example, a utility may purchase allowances when they are the least-cost strategy and then see the price of allowances rise, making them more expensive than other options. In that case, a public utility commission might question whether this purchase was prudent and who should bear the cost of the decision. As a result, utilities may be reluctant to trade without regulatory clarification on these matters. According to an official of a Phase 1 utility that needs allowances for compliance in Phase 2, the company decided to forgo buying allowances now because it perceived doing so as too risky.

Threat of Competition Is Making Utilities and State Regulators More Disposed to Trading

Despite their traditional risk aversion, some utilities are trading allowances. A couple of these utilities note that increasing competition in their industry provided the catalyst for them to trade. With support available from the Department of Energy (DOE), many state utility commissions are also orienting their regulatory approaches to this new competition by requiring utilities to conduct least-cost planning. Least-cost planning can encourage trading by requiring utilities to consider a wider range of compliance options than is traditionally the case. Even so, utilities are still likely to be reluctant to trade if the risk of trading remains with the utility and the profits with the ratepayer. Several market observers believe that utilities will need to be compensated for taking such risks.

Competition Puts Pressure on Utilities to Reduce Costs and Rates

Increasing competition in the utility industry is providing an impetus for some firms to enter the allowance market. These utilities are trading allowances to avoid the higher costs for scrubbers or maintain lower rates

²Examination of Utility Phase 1 Compliance Choices and State Reactions to Title IV of the Clean Air Act Amendments of 1990, Argonne National Laboratory, ANL/DIS/TM-2 (Nov. 1993).

for their customers. For example, even in a state where the utility commission has ruled that all cost savings resulting from trading accrue to the ratepayers, utilities were still in the allowance market to maintain low rates.

As a result of legislative and economic changes over the past decade, increasing amounts of wholesale electricity are being generated by power producers that are independent of regulated utilities, resulting in more industry competition. In a March 1993 report,³ DOE's Energy Information Administration noted that utilities' purchases of electric power from nonutilities have been increasing at an "astonishing" average annual rate of 31 percent since 1986 and that electricity in wholesale transactions now accounts for more than half of the electricity sold to retail customers. According to utilities active in the SO₂ allowances market, allowances provide a major opportunity to remain competitive as a result of lower compliance costs and rates.

For example, one midwestern utility's officials noted that they stopped building a scrubber, after spending about \$30 million, because purchasing allowances was cheaper. Despite a state law guaranteeing recovery of the reasonable costs for the scrubber, officials of this utility explained that purchasing allowances offered compliance without raising rates and that maintaining low rates was necessary to remain competitive.

State Commissions Are Adapting Their Approaches, Which Could Encourage Trading

Like utilities, state utility commissions are adapting their regulatory approaches to the new competition, with DOE's support. The most visible change is the adoption of least-cost planning, which could encourage more trading. Of the 21 states with utilities subject to Phase 1, 18 have requirements for least-cost planning, according to Argonne National Laboratory. Least-cost planning is a way of ensuring beforehand that a utility's decisions are prudent, rather than awaiting completion of a scrubber, for example. According to some of the commissions we met with, least-cost planning encourages utilities to consider a wider range of compliance options than they do under traditional regulatory reviews. By including decisions on allowances in least-cost planning, regulators could also consider how to treat allowances in rates, along with other utility investments.

³The Changing Structure of the Electric Power Industry 1970-1991, Energy Information Administration, DOE/EIA-0562 (Mar. 1993).

For commissions considering least-cost planning, DOE offers support in developing regulations. In October 1993, DOE created the Utility Commission Proceedings Participation Program, made up of technical and policy offices in DOE and EPA. This team participates in commissions' regulatory proceedings on such issues as least-cost planning, energy conservation, and environmental protection. DOE also has an Integrated Resource Planning team, which assists commissions on the technical aspects of least-cost planning. According to DOE officials, both of these teams have provided information to or intervened in proceedings before state commissions to help establish rules on least-cost planning, but to date, they have not addressed allowance trading. However, DOE and EPA officials agreed that in the future, these teams should offer to assist utility commissions in developing rules on trading because both utilities and ratepayers benefit from the lower compliance costs that trading offers.

The effect of incorporating decisions on allowances into least-cost planning is unclear at this point. If a state's least-cost plan specifies how excess allowances owned by the utility will be treated in ratemaking, least-cost planning could reduce this element of uncertainty and encourage trading. Yet most states, as noted earlier, have not specified how allowances will be treated in the ratemaking process. Although the least-cost planning process may focus utilities on least-cost options such as allowances, several utilities stated that they may not actively trade allowances as long as commissions follow traditional ratemaking, in which the risk of trading allowances remains with the utility and the profits remain with the ratepayers.

Incentive Regulation for Allowances Has Been Proposed

Some market observers, such as the Edison Electric Institute and NRRI, have proposed incentive regulation as a means of offsetting the effects of traditional utility regulation. They believe that utilities may forgo cost-effective opportunities in the allowance market as long as all profits flow to the ratepayer and all investment risk to the utility. These groups suggest that utilities will need to be compensated for their risks in the allowance market.

Under such an incentive approach, the commission could set an allowance price cap. If the utility outperforms this benchmark price, either by selling allowances at higher prices or by complying at lower costs, the utility keeps the difference. Conversely, if the compliance costs exceed the preestablished price cap, the utility is able to recover only the benchmark price. According to proponents of incentives, shareholders would obtain

returns from cost-effective trades and consumers would pay lower rates. Because risks and rewards would be more balanced than they are under traditional ratemaking, proponents also believe that incentive regulation would more efficiently encourage least-cost compliance than a lengthy least-cost planning process.

Although, according to NRRI data, no utility commissions have adopted such incentive regulation for their state's utilities, some are taking steps to encourage trading.⁴ One of the five utility commissions we talked with was considering this incentive approach. For many state commission officials, allowance trading is still a new concept. However, NRRI has advocated incentive regulation in numerous workshops for state commissions, and in fact, some are now considering ways to encourage utilities to recognize the potential benefits of trading.

For example, the Georgia Public Service Commission has directed its utilities to monitor the SO₂ market and buy allowances when they cost less than other compliance options. The New York State Public Service Commission is piloting a ratemaking scheme in which a utility's rate of return depends on how well the utility controls various production costs relative to similar utilities. New York officials suggested that allowances could be included as one measure of production costs.

FERC's Regulatory Treatment of Allowances Is Uncertain

Utilities have no guidance from FERC on incorporating allowance costs in the wholesale rates they charge for interstate transactions of electricity. FERC has jurisdiction over these transactions—growing in number—because it regulates interstate commerce in electricity. The importance of guidance from FERC is also underscored by the projection that the nine multistate registered holding companies,⁵ which are subject to FERC's jurisdiction, will hold almost 25 percent of all SO₂ emissions allowances by the year 2000. Some utilities have already asked FERC to address the issues of ratemaking and allowance transactions and of the multistate holding companies' compliance. While these requests are currently pending, FERC has issued no official guidance to date because it does not want to set a precedent before reviewing these specific utility cases and allowing time for the program to develop. FERC has limited itself to revising utilities'

⁴Public utility commissions in both Connecticut and Indiana have adopted an incentive mechanism for one utility in their state.

⁵These nine companies are corporations comprising utilities which operate in different states. For example, the Southern Company, one of the largest holding companies, includes five utilities supplying energy in most of Alabama and Georgia, portions of Florida and Mississippi, as well as in three other states.

accounting rules to include data on allowances.⁶ FERC decided not to require frequent reporting of allowance trades and prices as part of these revised accounting rules—as some state commissions suggested—although it recognized the usefulness of such data to market participants and expressed a willingness to revisit the issue.

The Clean Air Act does not prescribe how allowances should be treated in ratemaking, leaving state commissions and FERC free to determine their own approach. As discussed previously, traditional ratemaking does not encourage allowance trading. Moreover, states may treat allowances differently in ratemaking, and this variation can make compliance planning difficult for multistate utility systems. One multistate holding company official told us that his company would rather trade allowances through a private allowance broker than trade between two of the firm's utilities, which would require getting approval of proposed plans and costs from two state commissions.

Some market participants and analysts have urged FERC to be more active in setting a ratemaking framework for allowances. In the absence of direction from FERC, multistate holding companies and wholesale electricity buyers and sellers cannot be certain how allowances will be treated in their transactions and compliance plans. According to several utility officials and other market analysts we talked with, policy guidance from FERC could help to remove this uncertainty.

Issues of how to assign a value to allowances in wholesale transactions and how multistate holding companies can manage allowances among their individual utilities are currently pending before FERC. For example, the Allegheny Power System has submitted an allowance management plan dealing with these issues for FERC's review. The plan describes how Allegheny Power's subsidiary utilities will manage their allowances in the wholesale electricity market. FERC officials have stated that earlier action on their part would have set a precedent for the trading program before FERC could review utilities' specific requests. FERC officials noted that they preferred to allow utilities to come forward with their particular cases rather than issue guidance and establish a precedent that must generally be followed by all utilities. They also wanted to provide EPA, state commissions, and utilities with time to make the program work as efficiently as possible.

⁶FERC's Order No. 552 (Mar. 31, 1993); 58 Fed. Reg. 17982, 18007 (Apr. 7, 1993).

Despite its intentions not to do so, FERC has influenced how allowances are treated in ratemaking by issuing accounting rules for allowances. Several market analysts suggest that ratemaking issues should have been addressed first, followed by accounting rules consistent with this ratemaking framework. Although FERC stressed that its accounting rules did not prescribe how allowances should be treated in ratemaking, NRRI notes that some states have incorporated aspects of these rules into their ratemaking. For example, because FERC's accounting rules value allowances at their historical cost, several state commissions have also chosen to use the historical cost of allowances for ratemaking purposes. As a result, the allowances originally allocated by EPA are valued at zero by these commissions, since the utility is not charged anything for them. However, NRRI cautions that allowances are valuable assets and should not be valued at zero for ratemaking purposes.⁷

In adopting its accounting rules, FERC decided to collect data on allowance transactions in the annual reports that electric utilities file with FERC on, among other things, their income, earnings, and production costs. However, several state commissions suggested in public comments on the rules that more frequent reporting of allowance trades could reduce uncertainty about prices. Some utilities proposed making the collection of allowance data conform to FERC Form 423's reporting requirement. Form 423 is a monthly report filed by electric utilities on the cost and quality of their fuels. Data from Form 423 are published monthly and serve as the primary source of information on prices and the availability of utility fuels. However, FERC believed that more frequent reporting was unnecessary, stating that data on allowances available from EPA auctions and other sources might fill the need for price information. In adopting the annual reporting requirement, FERC noted that this issue might need to be revisited, depending on how information on the market developed. As noted in chapter 2, allowance price data are currently scarce and conflicting, and according to EPA officials, a more frequent reporting requirement by FERC on the number and prices of allowances traded would be helpful.

Although FERC is more accustomed to a role of passive ratemaking, responding to utility cases as a judicial body, FERC has taken active positions on some emerging issues. In 1988, according to FERC officials, FERC issued notices of proposed rulemaking describing its position on a more competitive wholesale electricity market. The officials noted that in

⁷Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances, The National Regulatory Research Institute, NRRI/93-16 (Dec. 1993).

subsequent decisions on rate cases, FERC carried out some of the ideas in the notices to encourage this market. Similarly, FERC recently issued a policy statement allowing electric utilities to submit rate proposals based on incentive regulation. Although states had used such regulation to cut costs, FERC did not have a history of using incentives to do so. Some of FERC's commissioners noted that the policy statement would provide a framework for FERC's review of incentive proposals.

Other Factors Have Been Cited as Additional Impediments to Trading

Five other market and regulatory factors have been cited by market participants as impeding trading. These other factors include problems with the design of EPA's auction, uncertainty about EPA's future regulations, lingering environmental concerns, state mandates on coal use, and the tax treatment of allowances.

Auction Design Contributes to Lower Prices and Uncertainty

Certain features of EPA's auction are contributing to a range of unexpectedly low allowance prices and creating confusion about what the market price should be. This confusion, in turn, may discourage trading. EPA officials have indicated a willingness to reconsider aspects of the current auction design consistent with language in the Clean Air Act Amendments of 1990.

EPA designed the auction as a "price-discriminating" auction, meaning that bidders pay what they bid. EPA's auction is distinguished by three features. First, as directed by the Clean Air Act, EPA, the largest seller of allowances in the auctions to date, has no minimum asking price. In essence, EPA must offer its allowances at \$0.⁸ Second, since winning bidders in the EPA auction pay the amount that they actually bid, the auction generates a range of winning prices. In contrast, many other auctions, such as trading on the New York Stock Exchange or auctions for securities, have a single, market-clearing price paid by all winning bidders and received by all sellers.⁹ Third, allowances are auctioned off by matching the lowest-priced offers to the highest-priced bids. For example, since EPA offers allowances at \$0, these allowances are matched with the highest bids submitted.

⁸As noted in ch. 1, EPA offered a total of 325,000 allowances for sale in the two auctions held to date; these allowances come from a reserve of allowances established by reducing utilities' allocations by 2.8 percent. Proceeds are returned to each utility on a pro rata basis. Other entities can offer allowances at any specified price, and these allowances are sold after those held by EPA.

⁹T. N. Cason, "Seller Incentive Properties of EPA's Emission Trading Auction," Journal of Environmental Economics and Management, No. 25 (1993), pp. 177-195.

These features, in combination, encourage certain strategic behaviors on the part of both sellers and bidders, resulting in lower prices for the allowances. Sellers have an incentive to place offers as low as possible in order to obtain the highest price. Meanwhile, buyers bid lower, knowing that most allowances offered will be very cheap, particularly EPA's zero-priced allowances. At the two auctions held so far, allowance prices have been up to a third below the prices reported for trades taking place outside the auction. According to utilities active in the market, the prices paid at the auction discourage potential trades or unnecessarily delay allowance transactions because buyers want to obtain allowances at the low prices reflected in the auction, while sellers find those prices unrealistic and below their costs of reducing emissions.

In addition, since the auction does not produce only one winning price, utilities find the range of winning prices confusing as an indicator of the actual market price. Officials of state utility commissions told us that they expect utilities to compare the price of allowances with the price of other options when developing compliance plans. Some noted that EPA's auction could be an indicator of price, but they believe that auction prices have been confusing and artificially low. According to several utilities, market analysts, and some economic research, an auction resulting in a single, market-clearing price, such as the one that occurs on the New York Stock Exchange, would provide more accurate prices.

According to EPA officials, language in the Clean Air Act Amendments of 1990 and discussions during debate on the 1990 Amendments suggest that the Congress believed a price-discriminating auction would maximize the proceeds paid to utilities for their allowances, since successful bidders pay what they bid. Although the Clean Air Act does not specifically mandate a price-discriminating auction, the statute requires that the auction allocate and sell allowances on the basis of the prices bid. When EPA designed the auction, some market analysts suggested in comments to EPA that while a discriminative auction met the statutory requirement, a single-price auction also met this test because the bidders' prices determine the price at which allowances are sold.

When EPA adopted the current auction design, it said it would monitor the auctions and identify any necessary changes to the design "that may be required to assure an orderly and competitive market."¹⁰ In addition, several EPA officials told us that EPA is willing to reconsider the issue, and the Deputy Assistant Administrator for Policy, Planning, and Evaluation

¹⁰56 Fed. Reg. 65592, 65596 (Dec. 17, 1991).

noted that it would be useful for EPA to have the flexibility to choose an auction design. We believe that an auction at which allowances are sold at a single price is consistent with the Clean Air Act's statutory language and the congressional goals for the auction expressed in the legislative history. A single-price auction could result in at least the same, if not higher, total proceeds to the extent that the incentive to submit lower bids present in the price-discriminating design would be removed.

Unresolved EPA Rules Create Uncertainty in the Allowance Market

Utilities, state officials, and market analysts praised EPA's efforts to get broad input and build consensus on rulemaking without trying to direct the allowance market's development. Many also commended EPA's attempts to educate commissions and utilities about allowance trading and encourage trading through visits and workshops. However, they did cite several problems that have added to uncertainty in the market and may hinder trading.

Most problematic is EPA's future regulation of other pollutants, such as toxic air emissions and nitrogen oxides. For example, a utility might choose an option to control SO₂ that precludes using the least-cost way of controlling these other pollutants. Alternatively, a utility might choose the least-cost option to control SO₂ as well as the other pollutants, but the public utility commission may not allow a utility to recover from ratepayers the costs of controlling other pollutants that are not currently regulated. EPA hopes to resolve many of these regulatory uncertainties before Phase 2 compliance plans are due in 1996. However, some utilities doubt that EPA will do so, given its history of missing deadlines. As noted in chapter 2, many utilities are simply banking allowances and not trading.

In July 1993, EPA announced that one of its rules could result in up to 1 million more allowances being available than intended. Under a plant substitution rule in Phase 1, utilities could substitute a unit slated for emissions reductions during Phase 2 for a unit slated for reductions during Phase 1, as long as equivalent emissions reductions were achieved. However, EPA subsequently found that this rule could permit the substitution of Phase 2 units for Phase 1 units with few resulting reductions—instead creating extra allowances. The allowances were considered extra because they were tied to emissions reductions that occurred before passage of the Clean Air Act Amendments of 1990. As a stop-gap measure, while EPA rewrote the rule, it approved—for one year only—compliance plans that the utilities had already submitted. Some utilities worried that further changes in rules could ensue, causing

uncertainty and discouraging trades. Other market analysts viewed this rule change as an isolated action, with little impact on trading. In May 1994, EPA signed a settlement agreement with utilities and environmental groups to close the loophole but allow a transition into the new rules.

EPA may have also impeded trading by deploying behind schedule the system it uses to track allowances. Although EPA issued a rule in January 1993 describing how the allowance tracking system would work, the computer software to run the system was not finished until March 1994. EPA officials stated that the delay occurred because of budget constraints and the complexity of developing a sophisticated automated system with adequate internal controls. According to utilities and allowance brokers, the delay impeded trading because the system was essential for establishing ownership of the allowances, recording trades, and conveying this information to the market. However, trading activity has not markedly changed since the creation of the tracking system, and other market participants stated that its delay was only a minor deterrent to trading.

Lingering Environmental Concerns May Hinder Trading

The trading program targets SO₂ emissions rather than the deposition of acid rain. While overall emissions will decline in the United States, New York State officials and the Adirondack Council, an environmental group, are concerned that trading does not ensure significantly less deposition in New York's Adirondack Mountains, an area seriously damaged by acid rain. Accordingly, they want to place restrictions on the sales of allowances to emissions sources located in the Midwest, upwind of New York.

Others believe, however, that talk of restrictions on trading is unnecessary and dampens market activity. The Environmental Defense Fund states that many of the dirtiest utilities upwind of New York are reducing emissions more than required in Phase 1 because of the economic incentives offered by trading. As noted in chapter 2, many utilities plan to attain significant extra emissions reductions in Phase 1. According to EPA, restrictions are not needed for environmental protection because most individual trades will not be large enough to cause measurable impacts on the environment. EPA also notes that New York's restrictions on utilities' allowance trades would not prevent emissions in upwind states. If a New York utility sold allowances to a downwind utility not affecting the Adirondacks, the downwind utility could, in turn, sell these allowances to an upwind utility.

According to some midwestern and New York utilities, New York State's discussion of trading restrictions has dissuaded them from trades with one another. They fear that such trades could be overturned by future restrictions.

The Clean Air Act required EPA to study the environmental impact of trading on sensitive areas such as the Adirondacks and to assess the need for corrective action. EPA has not completed this study, which was due November 15, 1993. Responding to a lawsuit filed by New York State and the Adirondack Council, EPA said that the report will be done by January 1995. Scientists at EPA and state environmental agencies note that long-term monitoring of acid rain—well into Phase 2—will be necessary to determine whether conditions improve in sensitive areas. According to the Deputy Director of EPA's Office of Modeling, Monitoring Systems and Quality Assurance, EPA's budget projections anticipate continued funding for such monitoring.

State Actions to Continue Use of Local Coal Limit Trading

Several states have passed laws to encourage their utilities to continue using coal mined within the state. These laws include incentives and mandates to use scrubbers and tax credits for local coal use. By limiting compliance choices, the laws discourage utilities from buying and selling allowances in some cases, even when doing so might be less costly. None of the state mandates refer to allowance trading as a compliance option.

As noted in chapter 2, over half of all Phase 1 compliance plans involve switching to lower-sulfur coal. Illinois, Indiana, Kentucky, Ohio, and Pennsylvania, with large high-sulfur coal reserves, have passed laws to protect coal mining jobs and prevent such switching. Ohio and Pennsylvania provided tax credits for the use of in-state coal, and Illinois required two of its utilities to use scrubbers. However, federal courts struck down the Illinois law and a similar one in Oklahoma as unconstitutional restrictions on interstate commerce. A similar court challenge is currently pending in Indiana.

IRS's Tax Treatment of Allowances May Discourage Trading

In 1992, the IRS issued guidance requiring the use of the historical cost of SO₂ allowances for purposes of tax calculation.¹¹ The IRS also said that EPA's allocations of allowances to utilities would not be taxable. In effect, these allocated allowances would be treated as having no value. If the allowances are sold by the utility receiving them, almost one-third of their

¹¹Revenue Ruling 92-16 and Revenue Procedure 92-91, IRS.

sale price would be taxed as a capital gain. According to some industry officials, this approach results in more favorable tax treatment of allowances not sold because internal uses of allowances are not subject to taxation. They say that utilities will be reluctant to sell their allocated allowances when almost one-third of the sale price is taxed.

However, other utilities and market analysts do not believe that this tax treatment is a major impediment to trading. They think that allowance sellers will consider these tax consequences and simply ask higher prices. In addition, they note that generating excess allowances for sale entails investing in scrubbers or fuel-switching equipment that can be capitalized and depreciated to yield tax benefits. According to one utility official, public utility commissions adjust electricity rates to allow utilities to recoup the taxes they pay. Thus, any taxes paid on the sale of allowances could be recovered in rates.

Conclusions

EPA's acid rain program is projected to reduce emissions and save billions of dollars a year over traditional approaches to pollution control, but the program could achieve substantial additional cost savings if utilities were trading allowances more actively. However, various obstacles are deterring more allowance trading. Some, such as the way the program was phased in and lingering environmental concerns, may become less significant as compliance deadlines approach and reductions in emissions occur. Others, such as the influence of EPA's auction or the way public utility commissions treat allowances in rates, may prove less tractable. Although it is unlikely that removing one particular obstacle could dramatically increase trading, federal action could lessen the effects of some of these impediments.

Reliable allowance prices would make trading easier by providing potential buyers and sellers better data on the price at which to trade. Although EPA's auction provides price information, it has resulted in multiple prices rather than a single price and lower prices than expected. Under the Clean Air Act, EPA can change this auction design to one that produces a single and more accurate price for all the allowances auctioned. In addition, FERC, which requires utilities to report allowance prices only once a year, has expressed a willingness to consider more frequent reporting. FERC currently collects data monthly from utilities on their fuel costs, and these data serve as a public source of information.

FERC, EPA, and DOE can also help resolve the impediment to trading created by the current lack of guidance on how allowances will be treated in ratemaking. FERC has been reluctant to issue guidance for fear of prematurely setting a precedent, but recent requests from utilities pending before FERC may now offer a vehicle for providing guidance. FERC also has taken positions on some previous emerging issues through policy statements or notices of proposed rulemaking. Moreover, through DOE's Utility Commission Proceedings Participation Program and Integrated Resource Planning team, EPA and DOE believe that they could help public utility commissions craft ratemaking that encourages the cost-effective use of allowance trading.

Many of the obstacles discussed in this chapter are not unique to SO₂ trading. As we discuss in chapter 4, similar or closely related issues are likely to confront a trading program to control CO₂ emissions.

Recommendations

To improve price information from EPA auctions and help clarify the regulatory treatment of allowances, the EPA Administrator should

- change the design of the auction so that it is a single-price auction and
- work with DOE's Utility Commission Proceedings Participation Program and Integrated Resource Planning teams to help state utility commissions and FERC decide how to treat allowances in ratemaking.

In addition, the Chair of FERC should

- require more frequent reporting of the number and prices of allowances traded and
- issue guidance on how FERC will treat allowances in ratemaking through a policy statement, notice of proposed rulemaking, or a ruling in one of the multistate utility cases on allowances currently before the Commission.

Agency Comments

As requested, we did not obtain written agency comments on a draft of this report. However, we discussed the factual information in the report with the Director and staff of EPA's Acid Rain Division and the Deputy Director and staff of FERC's Office of Electric Power Regulation. EPA generally agreed with the facts presented. FERC officials believe that it would have been counterproductive to issue generic guidance in advance of specific utility requests and before the trading program could develop. However, they agreed that utility cases currently before FERC may now

Chapter 3
Reluctance to Trade Has Been Due to
Various Regulatory, Industry, and Market
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offer a vehicle for providing guidance and encouraging trading. In addition, although FERC officials felt that other market entities might fill the need for price information, they indicated a willingness to consider more frequent reporting of allowance prices and transactions.

Experience With Sulfur Dioxide Trading Is Relevant in Designing a Domestic Trading Program in Carbon Dioxide Allowances

Experience with the SO₂ allowance trading program indicates that some of the program's features would be effective components in a trading program for the United States to reduce CO₂ emissions that may contribute to global climate change. Other features would be useful only if modified. For example, the SO₂ trading program ensures environmental protection by mandating an overall reduction in emissions, tracking compliance with emissions monitors, and imposing high enough penalties to deter noncompliance. A CO₂ program could be designed to include these features. However, as noted in chapters 2 and 3, certain features in the SO₂ program, by impeding trading, have prevented utilities from achieving the fullest potential cost savings in selecting options for complying with the required reductions in emissions. These features bear modification in any new program.

Under the two-phased approach of the SO₂ program, many potential sellers of allowances had to achieve emissions reductions before potential buyers of any allowances needed them. In the absence of this time gap in the requirements for emissions reductions, potential buyers and sellers of allowances would be more disposed to trade at the same time. In addition, having an allowance auction that results in a single, market-clearing price would send clearer price signals than the current SO₂ auction design allows for, making it easier for all buyers and sellers to agree on price.

A number of other issues are relevant in designing a CO₂ trading program. For example, how state public utility commissions and FERC carry out their mandates can encourage or discourage trading. Deciding what sources of CO₂ emissions to include in an allowance trading program is a more important consideration than it is for SO₂ because the sources of CO₂ are more varied. Finally, allowing trading across national boundaries, while going beyond the scope of a domestic trading program, offers potentially greater cost savings, but a program that included this component would also be much more difficult to implement.

Several Features of the Sulfur Dioxide Trading Program Would Be Effective in a Carbon Dioxide Trading Program

The SO₂ trading program has built-in safeguards to ensure that environmental protection is achieved regardless of how much or how little allowance trading occurs. These same features could serve as environmental safeguards in a CO₂ trading program for the United States.

**Mandating an Overall
Emissions Reduction
Helps Ensure
Environmental Protection**

Stipulating a fixed amount of emissions to be reduced nationwide by a specific date would help to make it clear that environmental protection is the primary goal of a CO₂ trading program. Separating the overriding environmental objective from the means of achieving it helps address concerns about whether trading will ensure meeting the environmental goal. Thus, mandated emissions reductions will occur regardless of how much trading takes place.

In the SO₂ program, choosing average 1985-87 emissions as the baseline against which to measure the reductions required to begin in 1995 and 2000 reduced utilities' incentive to maintain higher emissions for the express purpose of receiving larger initial allocations of allowances. It is more difficult for a utility to attempt such a strategy when the span of time is long between the baseline period and the date by which reductions have to be achieved. In addition, choosing an average of emissions over several years rather than singling out one year reduces the chance that the emissions baseline chosen does not represent normal economic activity.¹

**Reliable Monitoring
Facilitates Compliance**

The ability to continuously monitor emissions as part of a CO₂ trading program has both environmental and economic benefits that facilitate trading. For SO₂, title IV requires all utilities to install CEMS, which provide utilities and environmental regulators with timely information on SO₂ emissions. This information makes it easier for utilities to make sure they are complying with the law and for EPA and state regulators to detect noncompliance. CEMS help ensure that the flexibility to choose among compliance measures in a trading program does not jeopardize environmental goals.

CEMS can also play an important role in certifying allowances, which is critical to the smooth operation of a market. In addition, the continual flow of information on SO₂ emissions can provide utilities with an indicator of how well their production process is functioning.

The CEMS installed by utilities for the SO₂ program can also be used to measure CO₂ emissions. In fact, the Director of EPA's Acid Rain Division told us that EPA is currently receiving measures of CO₂ emissions from most sources of emissions covered by title IV.² He also stated that this

¹For instance, in an economic recession, emissions are typically lower. As a result, a smaller reduction is needed to meet a given emissions level.

²Section 821 of the Clean Air Act requires all affected sources subject to title IV to report either measured or estimated CO₂ emissions to EPA.

technology can apply to other large combustion sources. In addition, EPA can use available data on energy use and type of fuel to estimate the CO₂ emissions that result from the use of fossil fuels.³

Large Penalties Offset the Benefits of Noncompliance

Together with monitoring, large penalties can deter noncompliance. Under title IV, a utility can incur a penalty of \$2,000, indexed to inflation, for each ton of SO₂ emitted in violation of the law, which is far more costly than purchasing an allowance at today's prices. In addition, EPA reduces the noncomplying utility's allotment of SO₂ allowances for the following year. The purpose of these strictures is to eliminate any benefit from violating the law. These penalties also encourage trading to the extent that they prevent any dilution in the market value of allowances from trading or otherwise using counterfeit allowances.

A Carbon Dioxide Program Could Achieve Greater Savings If Trading Is Not Impeded

Some features of the SO₂ program have impeded trading. Modifying these features in a CO₂ program could result in greater savings by stimulating more trading earlier in the program.

Requiring All Sources to Meet Emissions Reductions at the Same Time Encourages Trading

If all regulated sources of CO₂ must comply with common emissions-reduction requirements at the same time, more potential sellers and buyers are likely to consider trading opportunities with the same urgency. Including all sources at the trading table is also likely to mean larger differences in compliance costs among the prospective traders, simply because there are more firms. In turn, more opportunities would occur to realize greater cost savings from trading.

The two-phased approach of SO₂ allowance trading under title IV has not encouraged trading because it requires many potential sellers of allowances to reduce emissions several years before many potential buyers have to do so. As a result, potential buyers have not felt the same urgency to reduce compliance costs as have potential sellers.⁴

³CEMs may be too costly for some sources that might be controlled under a CO₂ trading program.

⁴Buyers subject to Phase 2 of the SO₂ program can contract with sellers subject to Phase 1 for future delivery of allowances.

If phasing in CO₂ emissions reductions is desirable to contain compliance costs, all regulated sources could reduce their emissions according to a predetermined time schedule. This approach is likely to stimulate more trading than the system used in the SO₂ program, in which many potential sellers are separated from buyers in terms of when they have to decide about trading.

Special Allowance Pools
Affect Cost Savings From
Trading

The way allowances are allocated at the beginning of a CO₂ program can also affect the cost-saving potential of trading. Tying allowance allocations to the use of a specific pollution control measure or a specific activity such as energy conservation may result in lower cost savings.

In the SO₂ program, special allowance allocations, especially the bonus allowances awarded for using scrubbers in Phase 1, reduced the incentive to choose the lowest-cost option. Utilities were rewarded for installing scrubbers regardless of whether that was the least-cost compliance strategy.

Single-Price Auction Could
Result in More Trading

An auction that results in a single, market-clearing price for all sellers and buyers is likely to reduce price uncertainty and thereby encourage trading. In addition, EPA can offer any allowances it is holding for sale at prices that reflect the best available information on what they are worth. EPA can determine the price at which it offers its allowances with the assistance of market experts, in much the same way that a privately held company arranges the price for its initial offering of stock with a “market maker” or expert.

The auction design in the SO₂ program has resulted in allowances’ being sold at multiple prices, causing uncertainty about what constitutes a fair market price for allowances. This uncertainty is likely to discourage trading because it makes it more difficult for two trading parties to come to agreement about price. By contrast, a single-price auction results in one price that matches buyers’ and sellers’ needs.

If EPA were not constrained to offer allowances with no minimum asking price, it could price them according to their estimated market value. A market maker, such as an allowance broker or other market expert, could assist EPA. The purpose would be to ensure that EPA’s asking prices were not so low as to encourage potential buyers to bid less than they would in a competitive market.

Financing EPA's Allowance Tracking System and Reporting Prices Could Assist Program Development

If EPA could charge fees to help cover the costs of developing and administering an allowance tracking system, recording of trades of CO₂ allowances would be more rapid. In turn, faster tracking would not only enhance EPA's ability to monitor environmental compliance but would also reassure market participants, who view the tracking system as the official means to record their emissions allowances. To the extent that better tracking protects an ownership claim, it can facilitate trading.

EPA has cited limited budget and staffing resources and the need to add internal controls and auditing capability as reasons for delays in developing the tracking system for the SO₂ program. Also because of these constraints, the transactions must currently be entered in the tracking computer system "by hand" rather than electronically. EPA allows itself up to 5 days to record trades in SO₂ allowances. Although EPA has taken less than 5 days to record trades to date, it set this time period to handle the heavy trades expected near the end of each year.

The SO₂ allowance tracking system does not require utilities to report allowance prices because, according to EPA officials, doing so is not necessary to determine whether utilities are in compliance. Nor does EPA require utilities to report every allowance trade. However, to help reduce uncertainty about the price of CO₂ allowances, EPA could require utilities to report such prices, along with the number of allowances they traded to the tracking system. Alternatively, FERC could gather information on prices and volumes of allowances traded and could report trends as it does now for other commodities, such as coal, that utilities use to generate electricity.

Designing a Carbon Dioxide Trading Program Requires Consideration of Other Important Issues

Several other issues have implications for the effectiveness of a CO₂ trading program. As in the case of SO₂, the way state public utility commissions and FERC regulate public utilities can encourage or discourage trading of CO₂ allowances. However, sources of CO₂ emissions are much more varied than they are for SO₂, so decisions about what sources to include in a CO₂ allowance trading program are more critical. Whether to allow and how to implement trading across national boundaries are also important considerations.

Economic Regulation of Public Utilities Is Important

A CO₂ trading program, like the SO₂ program, would involve the nation's electric utilities. As the SO₂ program matures, state public utility commissions and FERC may develop regulations that do not discourage

trading in SO₂ allowances. To the extent that this happens, a CO₂ trading program could also proceed more smoothly.

Varied Sources of Emissions Could Mean Extending CO₂ Allowance Trading Beyond Electric Utilities

Utilities account for 70 percent of SO₂ emissions in the United States but only 36 percent of CO₂ emissions. CO₂ emissions from sources besides utilities may thus have to be reduced. As a logical first step, CO₂ allowance trading could be extended to industrial plants suited to allowance allocation and monitoring in much the same way as utilities are. According to one study by an official of EPA's Acid Rain Division,⁵ possible candidates include manufacturers of aluminum, cement, and lime. However, mobile sources, such as automobiles, trucks, and airplanes, which account for 32 percent of CO₂ emissions, might require another approach.

One option for controlling CO₂ emissions from mobile sources could be to regulate the carbon content of fuels. Instead of individually monitoring the emissions of millions of automobiles, trucks, and airplanes, refineries that produce these fuels would be allocated allowances consistent with the desired reductions of CO₂ emissions from mobile sources. Trading would determine the price of allowances, and refineries would share the cost of allowances with consumers through increased fuel prices.

Designing a system that includes other activities that contribute to overall CO₂ levels is considerably more complex because it is difficult to estimate and monitor the contribution of these activities to CO₂ emissions levels. For example, several types of land use lead to CO₂ emissions, such as forest clearing for agriculture or urban and industrial projects, and logging. In addition, soil and forest degradation lead to higher levels of CO₂. Conversely, reforestation can lead to reductions in CO₂. However, data on releases of CO₂ by forest degradation through logging, shifting cultivation, erosion, lowering of groundwater tables, and desertification are of poor quality or unavailable. In addition, tracking the impact of industrial and residential development on CO₂ emissions would be daunting. For this reason, including these sources of CO₂ in a carbon trading program could make it unworkable.

International Trading Could Increase Cost Savings

Unlike SO₂, which can lead to regional problems of acid rain, CO₂ poses a global environmental threat. Monitoring and enforcing emissions reductions would be less difficult in a domestic CO₂ trading program than

⁵B. D. Solomon, Global CO₂ Emissions Trading: Early Lessons From the U.S. Acid Rain Program, EPA, Acid Rain Division (Aug. 1994), p. 25.

in an international trading program, but the potential cost savings from trading are much larger if CO₂ trading is extended across national borders.

CO₂'s climate-warming potential is independent of where it is emitted. As a result, the geographic location where CO₂ emissions and reductions occur is not an issue in protecting against the threat of climate warming. This fact facilitates trading because it enhances the fungibility of CO₂ allowances; that is, an allowance to emit CO₂ in one place is equivalent to an allowance to emit in any other place.

Extending the trading of CO₂ allowances across national borders raises a number of important issues. Developing nations might resist an initial distribution of CO₂ allowances based on historical emissions levels because of concerns that such a distribution could impede their economic growth. On the other hand, industrialized countries might regard requirements to reduce emissions from their current levels as unfair, given past investments that they have made to reduce pollution.

Implementing effective monitoring and enforcement would also be a problem. Many countries have not invested as many resources in environmental protection as the United States has. As a result, the quality of data on global emissions is often poor, or the data are nonexistent. Nonetheless, the potential cost savings are greater if trading is extended across borders because many nations use older and more polluting production technologies than the United States. To the extent that reducing CO₂ is cheaper in these other countries, they would be net sellers of CO₂ allowances to the United States. In addition, a decision by the United States to reduce its CO₂ emissions unilaterally could result in exporting and increasing CO₂ emissions abroad. This "slippage" in a domestic trading program might lead to much smaller reductions in CO₂ worldwide than expected.

One way to extend the scope of a domestic CO₂ trading program is through bilateral trading between the United States and another country. An experiment in bilateral trading could make it easier to determine how to make trading in CO₂ allowances feasible across national borders. And, if successful, it could serve as a catalyst for other bilateral or multilateral arrangements.

Restricting CO₂ Emissions
Could Affect the Market
for SO₂ Allowances

One of the challenges of developing a trading program to comply with lower CO₂ emissions limits is doing so without disrupting the ongoing SO₂ program. A program to reduce CO₂ emissions could reduce the demand for

SO₂ allowances enough to derail the market in SO₂ allowances. For instance, depending on the size of the CO₂ reduction mandated, coal-fired utilities might have to switch to natural gas to comply. Because the combustion of natural gas produces no SO₂, utilities would no longer need SO₂ allowances, thereby reducing their value. Utilities that bought large numbers of SO₂ allowances to comply with title IV could see the value of their allowances diminish. Similarly, large investments in scrubbers built to reduce SO₂ could be wasted if utilities switched to natural gas, because scrubbers cannot remove CO₂. To the extent that companies anticipated these investment losses, their enthusiasm for participating in such trading programs could wane, possibly resulting in squandered opportunities to protect the environment at less cost.

Modeling Analysis of Three Allowance Trading Scenarios

In this appendix, we present the results and methodology of our consultant's modeling analysis. Our consultant analyzed three allowance trading scenarios for Phases 1 and 2. The purpose of the analysis was to use the most recent data available to estimate (1) the economic potential for trading among affected utilities, (2) the economic impact of reduced trading on the nation, and (3) the economic impact of reduced trading on each state. To do so, our consultant estimated the costs of mandated SO₂ reductions under three trading scenarios:

- traditional "command-and-control" compliance with no trading,
- trading within utilities only,¹ and
- increased allowance trading between utilities.

These estimates as well as projected impacts of trading for each state are presented below. In addition, the extra emissions reductions expected in each state in Phase 1 are listed. We contracted with a consulting firm, Van Horn Consulting of Orinda, California, to conduct this modeling analysis.

Description of the Modeling Exercise

Utilities' strategies and costs for meeting the SO₂ emissions reductions set by the Clean Air Act Amendments of 1990 were projected for Phase 1 (1997), early Phase 2 (2002), and later Phase 2 (2009). The decisions of utility systems on how they would comply were simulated using data at the unit level and on utility systems' requirements for over 200 utility systems. Detailed information on all existing and announced coal- and oil-fired generating units over 25 megawatts was used. Projections of compliance costs under command and control, internal trading, and interutility trading are based on simulations of the operating characteristics of the plants and utility systems.

Modeling Approach and Data

The analysis begins with data and calculations for each individual generating unit and results in projections of emissions, generation, operating characteristics, and costs for each unit and its utility system. The information describing each unit included on-line and retirement dates; net generating capability; heat rates, generation levels, and emissions; existing emissions control equipment; emissions limits before the Clean Air Act Amendments of 1990 and the number of allowances allocated under the act; and the composition and costs of alternative fuels. Fuel-related costs included site-specific fuel transportation costs, projected fuel prices excluding transportation, unit-specific costs, and

¹This scenario also includes trades between utilities that have already been announced.

penalties for fuel switching. Information characterizing historical and current unit operations was derived largely from data provided by the North American Reliability Council, the Federal Energy Regulatory Commission (FERC), and the Department of Energy (DOE). Other data, such as projected capacity factors for different time horizons, have been developed through additional analyses and evaluation of forecasts, such as those provided by the North American Reliability Council regions, DOE's Energy Information Administration, and various analysts.

Estimation Procedures

The objective of modeling each power plant unit in detail is to characterize each unit—including its fuel, control technologies, and costs—under each of several levels of potential emissions reductions. The model selects the most economical combination of fuel and control technology meeting each progressive emissions reduction, typically by examining different fuels and fuel blends along with the retrofit of different emissions control technologies required to achieve each emissions reduction. The model then selects each utility's overall compliance strategies from among the numerous alternatives available at all of the utility's individual units. A wide variety of unit-specific and general constraints on what compliance measures are required, allowed, or prohibited can be specified, as can varied constraints on allowance trading among units and among systems. The model also assumes that compliance measures, such as Phase 1 scrubber retrofits that utilities have already announced, occur.

Under the command-and-control scenario, the model assumes that each unit selects the least-cost alternative for reducing emissions that would comply with that unit's SO₂ allowance allocation, without any allowance trading. Under the internal trading scenario, the model assumes allowance trading only among units within each utility system, and each utility selects the lowest marginal cost measures among all the available alternatives at the different units within its own system to meet its systemwide allocation of emission allowances. However, the model assumes that interutility trades and allowance transfers that utilities have announced to date occur. Under maximum interutility trading, the model derives the lowest marginal cost measures on a nationwide basis, regardless of who owned the units, to meet the total allowance allocation or cap at the lowest cost. The model balances the resulting undercontrol and overcontrol of emissions by different utility systems relative to their individual total allowance allocations with the net allowance purchases and sales, respectively, for those systems.

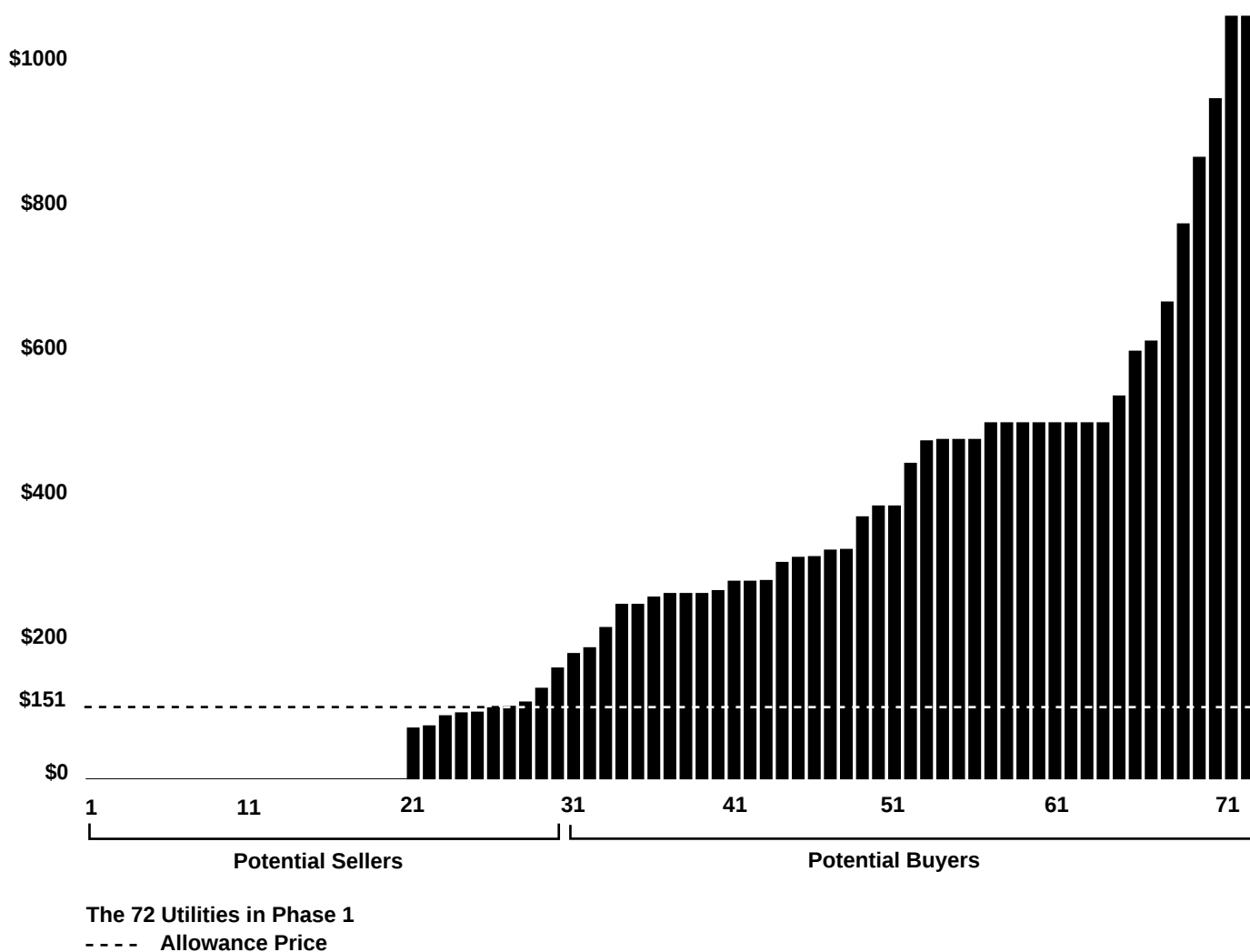
Results of the Modeling
Exercise

Our consultant's modeling results suggest that the economic basis for more trading exists. Estimated differences among utilities' marginal compliance costs appear sufficient to warrant trading in both Phase 1 and Phase 2.² Figure I.1 shows a large variance in utilities' estimated compliance costs during Phase 1. Figure 2.3, in chapter 2, shows a similar variation in marginal costs during Phase 2.

²Marginal cost refers to incremental cost.

Figure I.1: Estimated Costs of Reducing Emissions Compared With Allowance Price for Phase 1 Utilities

\$1200 Incremental Cost per Ton of SO₂ Abatement



Note: Nineteen potential sellers have incremental costs at or near zero. Costs are in 1992 dollars per ton.

Costs and Emissions Under Three Trading Scenarios

Our consultant used the most recent data available to estimate the costs of attaining mandated SO₂ reductions. Annual costs were estimated for 3 years in the program: 1997 (Phase 1), 2002 (Phase 2), and 2009 (late Phase

2). For each trading scenario, table I.1 presents these cost estimates and projections of SO₂ emissions as utilities draw down the stock of allowances saved from Phase 1 and use them for compliance in Phase 2.

Table I.1: Projected Annual Costs and Emissions

Millions of 1992 dollars

Year	Command and control		Internal trading		Interutility trading	
	Cost	SO ₂	Cost	SO ₂	Cost	SO ₂
1997	\$1,310	11,185	\$1,080	11,471	^a	^a
2002	4,495	7,492	2,592	8,933	\$1,440	10,419
2009	4,913	7,405	3,076	8,213	1,997	9,352

Note: SO₂ emissions are in thousands of tons.

^aThe projection for internal trading in 1997 represents a likely scenario given utilities' current compliance strategies. The impacts of interutility trading were not estimated for Phase 1 because most utilities had already committed to other strategies.

Estimated Cost Savings Among States From Greater Trading

Our consultant's modeling suggests that more trading could reduce utility compliance costs in many states. Table I.2 compares the projected annual savings from greater trading with current levels of internal trading.

Table I.2: States' Estimated Annual Costs and Potential Savings From Trading

Millions of 1992 dollars

State in which plant is located	Costs with command and control	Costs with internal trading	Costs with interutility trading	Potential savings ^a
PA	429	270	135	135
IN	454	318	235	83
NY	88	32	(46) ^b	78
FL	187	135	75	60
DE/NJ/MD/DC ^c	191	114	56	58
IL	254	182	132	50
WI	61	2	(48)	50
AL	196	127	78	49
NC	209	107	62	45
LA/MS	57	59	14	45
TX	71	4	(38)	42
KY	187	140	101	39
OH	648	399	360	39
SD/ND	26	24	(11)	35

(continued)

Appendix I
Modeling Analysis of Three Allowance
Trading Scenarios

Millions of 1992 dollars

State in which plant is located	Costs with command and control	Costs with internal trading	Costs with interutility trading	Potential savings ^a
CA/NV	1	1	(32)	33
AR	28	28	(4)	32
AZ/NM	13	1	(28)	29
UT/WY	19	0	(29)	29
CT/MA	28	22	(6)	28
MI	37	0	(24)	24
MO	151	64	41	23
OK	47	18	(4)	22
SC	95	46	24	22
MN	13	0	(19)	19
TN	214	192	175	17
VA	114	39	22	17
KS	0	0	(13)	13
IA	56	25	15	10
GA	155	31	21	10
NE	12	0	(7)	7
CO	41	0	(5)	5
WV	361	204	201	3
ME/NH/RI	35	6	5	1
OR/WA/MT	17	2	2	0
Total	4,495	2,592	1,440	1,152

Note: Estimates for the year 2002.

^aThe column "potential savings" compares internal trading only with maximum interutility trading.

^bParentheses indicate opportunities for states to sell enough allowances to offset their costs and make a net profit.

^cStates with few utilities have been aggregated.

Projected Annual
Emissions in Phase 1

Based on the compliance strategies currently being chosen, projections for Phase 1 suggest that utilities in many states will attain extra reductions in emissions, as shown in table I.3.

Appendix I
Modeling Analysis of Three Allowance
Trading Scenarios

Table I.3: Projected Extra Emissions Reductions in Phase 1 by State

State	Legal limit ^a	Projected emissions	Extra reduction ^b	Percent extra reduction
OH	1,534	1,063	471	30.70%
GA	590	381	209	35.42
WV	542	348	194	35.79
IN	756	570	186	24.60
MO	478	306	172	35.98
PA	666	495	171	25.68
NY	274	107	167	60.95
WI	241	106	135	56.02
KY	449	320	129	28.73
TN	394	290	104	26.40
AL	228	183	45	19.74
MI	148	108	40	27.03
MN	78	50	28	35.90
ME/NH/RI ^c	52	35	17	32.69
IA	52	46	6	11.54
CT/MA	11	6	5	45.45
FL	177	173	4	2.26
IL	602	598	4	0.66
LA/MS	66	62	4	6.06
DC/DE/MD/NJ	212	209	3	1.42
NC	3	0	3	100.00
KS	4	2	2	50.00
VA	10	9	1	10.00

Note: Data are for 1997 and in thousands of tons per year. Only utilities affected by Phase 1 are included in state data, except for utilities only affected by Phase 2 that have purchased allowances for future use, like those in North Carolina.

^aThe category "legal limit" includes initial annual coal and oil allowance allocations plus scrubber bonus pool allowances, projected substitution unit allowances, auction purchases, internal utility allocations across state lines, and net trades.

^bExtra reduction below limits set by title IV.

^cStates with few utilities have been aggregated.

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