EMISSIONS TRADING

UNDER THE U.S. ACID RAIN PROGRAM:

EVALUATION OF COMPLIANCE COSTS

AND

ALLOWANCE MARKET PERFORMANCE

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I. EXECUTIVE SUMMARY

Title IV of the 1990 Clean Air Act Amendments introduced the world's first large-scale, public policy experiment in the use of tradable permits to achieve an environmental goal. Title IV, sometimes known as the U.S. Acid Rain Program, mandates that electric utility sources achieve a 50% reduction from their 1980 levels of acid-rain precursor emissions—both sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The major part of the reduction, which concerns SO_2, is to be achieved entirely by marketable emission permits. The initial limitation of SO_2 emissions took effect in 1995, when major generating units with relatively high emission levels were issued permits, or "allowances," requiring an intermediate aggregate reduction of emissions during a five-year "Phase I" period. The full reduction will be implemented in Phase II: in the year 2000, all electricity-generating units will be issued allowances limiting SO_2 emissions nationally to about 9 million tons—roughly 50% of their 1980 emissions.

This "cap and trade" approach to emissions control establishes an aggregate emissions limit, distributes to individual sources a number of permits equal to this limit according to certain criteria, and allows individual sources to trade permits with other parties or to bank unused permits for later use. No further emission or technology requirements are imposed; sources are required only to have a valid permit for each ton of SO_2 emitted.

The year Title IV took effect was marked by significant overcompliance. A total 8.70 million allowances were issued to 72 operating utilities to cover emissions at 445 electricity-generating units having a total capacity of 130 GW^e. These units had emitted 10.68 million tons of SO_2 in 1985; their 1995 emissions, however, were only 5.30 million tons—about 3.9 million less than would have been expected without Title IV, and 3.4 million below the "cap." The 1995 emissions reduction is the more remarkable in that the cap required only a slight reduction beyond that achieved through 1994, because emissions had already declined significantly prior to 1995—largely due to railroad deregulation's effects on the competitiveness of western low-sulfur coal in the Midwest, where local high-sulfur coal had traditionally been used. The 1995 reduction in SO_2 emissions was achieved about equally by retrofitting equipment (*e.g.*, installing "scrubbers") to desulfurize flue gas, and by switching to lower-sulfur coal. Despite fears that "hot spots" would result from emissions permit trading, significant 1995 emissions reductions occurred in the upper Ohio River Valley, where emissions from high-sulfur coal use have caused particular concern.

A viable market for allowances has developed, despite considerable early doubt, providing current information on the value of additional abatement as well as more opportunities to reduce compliance costs. In the first years after allowances were issued, few allowances were traded outside of a mandated EPA auction; in 1994, however, the volume of private trades increased notably, and various indicators of market price converged to a relatively tight range of values for allowances. Furthermore, derivative instruments—options, swaps, forwards, and futures—have emerged and are being used increasingly.

As this private market for allowances has developed, the mandated EPA auction has receded in importance from its original roles of providing early, transparent indicators of allowances' market value and stimulating the development of a functioning allowance market.

Electric utilities' use of allowances also does not appear to have been restricted significantly by state regulations. Allowances were transferred in all 24 states containing Phase I-affected units, as well as in ten of the 23 states that have only Phase II-affected units.

The total cost of achieving the 3.9-million-ton reduction in SO_2 emissions in 1995 was at the lower bound of earlier predictions. We estimate the appropriately annualized total cost to have been approximately $725 million, in 1995 dollars—an average total cost of $187 or $210 per ton of SO_2 removed, depending on whether 425,000 tons of apparently costless emissions reductions are included. Earlier studies of compliance costs for Title IV predicted an early Phase I emissions reduction of 3.1–4.4 million tons, at an average total cost ranging from $180 to $307 per ton of SO_2 removed.

On a total-cost basis, scrubbing (though its cost has been much lower than predicted) has proved to be a more expensive means of compliance than switching fuel. On average, retrofitted scrubbers achieved emissions reductions in 1995 at an average cost of $265/ton SO_2, compared to $153/ton for fuel switching—in marked contrast to earlier studies that estimated average total costs for scrubbing to be $450–500/ton. Most of the difference between predicted and actual scrubbing costs has been due to lower-than-predicted operating costs and to greater-than-expected utilization rates of scrubbers that spread the initial fixed cost over more tons of SO_2 removed.

While the average total cost of achieving Title IV's mandated reduction in SO_2 emissions has been at the low end of early estimates, the price of allowances, at about $100 (equivalently, $100 per ton of SO_2 removed), has been well below earlier predictions of Phase I allowance prices, which ranged from $250 to $400. The explanation for this disparity is two-fold: first, the price of allowances reflects short-run, marginal cost—not necessarily long-run, average total emission control cost; and, second, mistaken expectations concerning the value of allowances led to overinvestment in compliance during Phase I. Most decisions to invest in scrubbers were made early—before the first EPA auction, when expected allowance prices were well above the values that later materialized—or in response to explicit incentives in Title IV and state regulations to encourage such investment during Phase I. Though the total cost per ton for scrubbing is relatively high, the ongoing operating cost is low. Once an investment in scrubbers is made, the capital cost is sunk, and the only cost affecting operating decisions is the variable cost—which is generally below even the surprisingly low allowance prices. In addition, expectations of a run-up in low-sulfur coal prices led many utilities to contract early for low-sulfur coal, which resulted in an even larger current supply of allowances. The price that emerged in the allowance market reflected a short-run equilibrium of current supply of and demand for allowances (or, equivalently, the current value of additional abatement), given past investment in scrubbers and current contract commitments to low-sulfur coal. The 1995 prices are almost certainly below the long-run marginal cost of emissions control.

The promise of "emissions trading"—the reason it has been advocated as a means for achieving environmental goals—lies in the lower overall cost of compliance possible as participants with lower-cost emissions-reduction possibilities abate more to sell allowances to those who can avoid more costly emissions reductions by acquiring additional allowances. All earlier studies of Title IV compliance costs predicted significant cost savings from emissions trading, though judgments of how much trading would occur differed considerably. In actuality, 45% of allowances issued for 1995 were used in a manner that implied emissions trading either among units or through time. Additionally, cost-saving behavior is indicated by the extremely heterogeneous response of generating units to the new SO_2 emission requirements. Ninety-eight of the 445 affected units acquired a total of 540,000 additional allowances to cover emissions greater than would have been "permitted" by allowances issued to them. Another 200 units reduced emissions in 1995 more than required to meet their allowance issuance, in order to compensate for the 540,000 tons of emissions reductions avoided by the aforementioned 98 units, and to bank an additional 3.4 million allowances, which will defer for several years more expensive emissions

reductions required in Phase II. Cost-saving behavior is also indicated by the 50% decline in the premium paid for low-sulfur coals in the primary coal-producing region of Central Appalachia in early 1995. This premium fell because bundling higher-sulfur coal with allowances was cheaper than purchasing lower-sulfur coal at the premium prevailing prior to the onset of Phase I.

Estimation of 1995 cost savings from emissions trading is fraught with conceptual and empirical difficulties that prevent us from offering a firm figure. For one thing, the hypothetical alternative program from which savings are to be calculated is not obvious. Nevertheless, we believe cost savings have been achieved relative to plausible alternatives, as uniformly predicted by earlier studies, although those savings are probably less than would be implied by simple extrapolation of the earlier predictions. Our rough estimate of the cost savings attributable to emissions trading in 1995 lies between $225 and $375 million, in current dollars, which implies that the cost of compliance with Title IV would have been one-third to one-half again as costly had electric utilities simply reduced emissions without taking advantage of the emissions-trading provisions.

Definitive conclusions cannot be drawn from one year's experience, but a few tentative findings do emerge. In particular, Title IV—while holding its share of surprises—has demonstrated that large-scale emissions-trading programs can work more or less as described in textbooks, without offsetting environmental costs. Judging from 1995 results, utilities did take advantage of the cost-saving flexibility provided by emissions trading—to a surprising extent, given the conservative nature of the electric utility industry and uniformly low expectations for emissions trading among analysts. Experience with Title IV has also shown that efficient, competitive private markets for tradable permits can develop. As in any real-life program, some features of program design by public parties and of implementation by private parties could, in retrospect, have been done better, though these defects have proved to be more the exception than the rule. All in all, this market-based alternative to conventional command-and-control approaches to environmental regulation has offered a refreshingly positive experience. That being said, it bears emphasizing that neither textbook perfection in market performance nor major technological breakthroughs in the cost of controlling SO_2 emissions have yet been achieved. Nor should they be expected. While experience with Title IV supports the contention that market-based approaches to environmental regulation cost less than approaches which ignore markets, it does not obviate the necessity of carefully weighing the benefits against the still positive, albeit lower, costs of the environmental goal to be achieved.

II. INTRODUCTION TO TITLE IV

A. Significance of the Program

Title IV of the 1990 Clean Air Act Amendments (1990 CAAA), also known as the U.S. Acid Rain Program, mandated a 10-million-ton (or 50%) reduction from 1980 levels of acid-rain precursor emissions from electric utilities. Although both sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions are affected by Title IV, the major part of the reduction concerns SO_2, abatement of which is being achieved entirely by fully tradable emission permits, or "allowances."[1] As such, the reduction of SO_2 emissions under Title IV is the world's first large-scale application of these market-based instruments in a public policy to achieve an environmental goal.

The basic approach to emissions control in Title IV is simple: an aggregate annual cap on national SO_2 emissions defines the number of emission allowances available for allocation to electricity-generating units each year. To emit SO_2 legally during a given year, an affected unit (*i.e.*, one subject to Title IV's SO_2 constraint) must have enough allowances valid for use that year to cover all its emissions. Title IV also requires each affected generating unit to have a continuous emissions-monitoring system (CEMS) on each exhaust stack, or flue, to measure actual SO_2 emissions, and report those emissions to the Environmental Protection Agency (EPA). At the end of the year, each source must have enough allowances in an account maintained by the EPA to cover all its recorded emissions, or be subject to significant penalties.

Allowances are fully tradable: utilities may acquire additional allowances by purchase or transfer to "cover" emissions in excess of their units' allocations in a given year ("spatial trading"). Alternatively, utilities may reduce emissions to less than the allowance allocation to some units in order to sell the unused allowances, or transfer them to other units for use that year, or it may "bank" the allowances for future use. Utilities cannot, however, "borrow" from future allocations to cover current emissions.

This emission-reduction and trading program marks a fundamental departure from the regulatory framework that has governed SO_2 emissions since the early 1970s. The first significant federal air-pollution legislation, the 1970 Clean Air Act Amendments, led to source-specific emission *rate* limitations on existing plants and the imposition of a *uniform rate* limitation on emissions from all new sources (*i.e.*, units). The 1977 Amendments altered this uniform new source performance standard (NSPS) by requiring a "percent reduction" that effectively mandated flue gas desulfurization—"scrubbing"—even if a new unit could meet the 1970 NSPS rate limit of 1.2 lb SO_2 per million Btus of heat input (hereafter #/mmBtu) without scrubbing. The regulatory framework governing SO_2 emissions prior to 1990 is generally described as "command-and-control": air pollution regulation focused on *individual* sources, their emission *rates*, and the application of specific *control technologies* to sources with certain attributes. In contrast, Title IV mandates no technology, offering electric utilities instead the

[1] The NO_x part of Title IV, which does not become effective until the beginning of 1996, permits only limited intra-utility trading among sources.

flexibility to choose whether and how to reduce emissions at any specific source.[2] Unlike the earlier regulatory structure, Title IV places an absolute limit on *aggregate* national SO_2 emissions only. Individual sources' flexibility in compliance arises from the tradability of emissions permits: sources for which reduction would be most costly can essentially pay other sources that can reduce emissions less expensively, to do so on their behalf. The result is lower-cost achievement of the environmental objective.[3]

This report evaluates the effectiveness and cost of Title IV in 1995, the year these provisions became binding. The underlying research was funded by the National Acid Precipitation Assessment Program in support of its Quadrennial Report to Congress, as required by the 1990 CAAA, and was conducted by the Center for Energy and Environmental Policy Research (CEEPR) at the Massachusetts Institute of Technology. This report serves as a summary only; discussions of theory and methodology, detailed data, and supporting econometric work can be found as published in CEEPR working papers (referenced herein), more of which are forthcoming.

In contrast to earlier studies of compliance with Title IV, this report has the advantage of hindsight. The focus here is on what actually happened in 1995, using data now available concerning emissions, investments in compliance, and fuel deliveries at affected units. While data on emissions and fuel deliveries are publicly available, information on investment cost is contained mostly in trade-press reports, particularly from earlier compliance studies by the Electric Power Research Institute (EPRI). To supplement such readily available data, CEEPR conducted a survey of affected electric utilities, for which confidentiality of individual responses was promised, concerning compliance actions, costs, and emissions trading in 1995.[4] We have also benefited significantly from innumerable discussions and comments from

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[2] The emission rate constraints imposed by earlier legislation and regulation remain in effect, so that sources are free to adjust emission rates only within what is permitted by the applicable State Implementation Plan. In practice, emission rates for many sources have been well below these limits.

[3] A simple example illustrates the benefits of a tradable permit program. Imagine a world with two generating plants, and suppose the environmental goal is to reduce SO_2 emissions by two tons from current levels. Plant 1 can reduce SO_2 emissions at a cost of $25 per ton. Plant 2 can do so at a cost of $100 per ton. One command-and-control approach to achieving the goal would be to mandate that each plant reduce emissions by one ton—at a cost of $25 for Plant 1 and $100 for Plant 2 (total cost $125). The tradable permits approach is to issue each plant allowances equal to the plant's current emissions minus one ton. If Plant 1 can sell an allowance to Plant 2 for $30, Plant 1 has incentive to make an additional one-ton reduction and sell Plant 2 the unused allowance, generating for Plant 1 a $5 profit (cost to reduce for Plant 1 = $25; revenue from selling an allowance to Plant 2 = $30). Plant 2 is happy to purchase an allowance from Plant 1 for $30 because it would cost Plant 2 $100 to reduce one ton itself . The cost of this approach is $20 for Plant 1 (($25x2) –$30) and $30 for Plant 2, for a total cost of $50. With tradable permits, each plant is better off than under command-and-control (Plant 1: $20<$25; Plant 2: $30<$100) and total costs are lower ($50<$125).

[4] Several electric utilities responded to our questionnaire, representing 37% of the aggregate affected capacity in Phase I, or 42% of aggregate 1990 SO_2 emissions from affected units. These and a few other utilities provided additional information by phone, enabling us to contrast and complement publicly available data to obtain a more reliable appraisal of actual compliance.

those most involved in Title IV compliance, at electric utilities, allowance trading firms, and U.S. government agencies.[5]

B. Specific Requirements

A tradable permits program involves specification of an emissions ceiling, the issuance of permits ("allowances") for emissions that are *de facto* property rights, and the ability to trade these allowances.[6] In Title IV, the emissions ceiling, or cap, applies to SO_2 emissions from electric generating plants in the 48 contiguous United States, set at about 9 million tons per year, effective from the year 2000. This cap is to be achieved in two phases:

- During Phase I (1995–99), an intermediate aggregate limit on SO_2 emissions is placed on the 263 generating units listed in Table A of the legislation.[7] These units, totaling 88 GW^e of electric-generating capacity, are located in 110 power plants owned by 61 operating utilities. They are targeted by the legislation because their emission rates in 1985 exceeded 2.5 #/mmBtu and their capacities exceeded 100 MW^e.
- In Phase II, which begins in the year 2000, virtually all fossil-fuel-fired electric-generating units will be included under the final 9-million-ton national cap on aggregate annual utility SO_2 emissions.

The Phase I and Phase II caps are enforced through the annual issuance of tradable emission allowances, each of which permits the holder to emit one ton of SO_2 in the year issued or later.

A total of 8.69 million allowances were issued for emissions in 1995; 5.55 million of these are being allocated to the 263 Table A units every year of Phase I according to a basic formula by which each unit receives an amount equal to an emission rate of 2.5 #/mmBtu multiplied by the unit's average heat input during the baseline period, 1985-87.[8] The remaining three million allowances issued for 1995 resulted from special legislative provisions for Phase I "extension" units (1.35 million allowances), "substitution"

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[5] The list of those to whom we are indebted is too long to cite in its entirety, but certain institutions deserve special mention. Our report would not have been possible without the data and background unstintingly provided by the Acid Rain Division of the Environmental Protection Agency and the Energy Information Administration of the Department of Energy. Cantor Fitzgerald Environmental Brokerage Services provided a continual stream of information and replies to questions on allowance pricing and transactions. The electric utilities which responded to our questionnaire greatly assisted our interpretation of publicly available data. Finally, we are indebted to colleagues at Resources for the Future and the Electric Power Research Institute for stimulating and continuing exchanges of views on Title IV.

[6] See Tietenberg (1985) for a complete analysis of emissions trading programs. For a more rigorous theoretical analysis, see Montgomery (1972).

[7] Table A of Title IV (see CAA §404(a)(1)) became Table 1 in the implementing regulations, and is sometimes referred to as such.

[8] See Kete (1992) and Joskow and Schmalensee (1997) for a full discussion of permit allocation for Phases I and II, and the many departures from the basic allocation rule, particularly in Phase II.

and "compensation" units (1.33 million allowances), an amount auctioned by the EPA annually (150,000), and 314,000 early-reduction credits for certain units.

The Phase I "extension" provisions offer 3.5 million additional allowances, total, throughout Phase I (roughly 1.3 million for each of 1995 and 1996, and 300,000 for each of the next three years) to utilities that propose to reduce emissions via flue gas desulfurization. These provisions, which offer an explicit incentive for scrubbing,[9] provide extra allowances that effectively delay the onset of Phase I for Table A units retrofitted with a scrubber by January 1, 1997, ostensibly to cover the construction period for retrofitting. Extension allowances have been received by 12 of the 16 utilities (for 18 of the 26 generating units) retrofitted with scrubbers.

The "substitution" and "compensation" provisions provide further flexibility for meeting Phase I emission requirements by permitting electric utilities to substitute other units for those designated in Table A, or to reduce generation at Table A units below the baseline level:

- Under the *substitution* provision, an electric utility can nominate one or more non-Table A units to make reductions in lieu of a commonly owned or operated Table A unit. Those non-Table A units then receive allocations of allowances approximately equal to their respective historic emissions and, for all intents and purposes, become Phase I-affected units.
- Under the *compensation* provision, an electric utility can reduce emissions at a Table A unit by reducing electricity generation at that unit below its baseline levels; the source of any compensating generation must be designated, however, and, when that compensating unit is sulfur-emitting, an allocation of allowances is made to it based on its historical usage, so that it essentially becomes a Phase I-affected unit, as well.

The response to these special legislative provisions was substantial: 42 operating electric utilities used the voluntary compliance program to bring 182 Phase II units, representing 41.6 GW^e of power (47% more capacity), under Phase I requirements, almost all (175) as substitution units.[10] In contrast, similar provisions under which industrial sources could voluntarily opt-in were little used because of the high transaction costs.[11]

In Phase II, every fossil-fuel-generating unit exceeding 25 MW^e in electric-generating capacity will receive an allocation from 9.4 million allowances available annually from the year 2000 until 2009, and 8.95 million available annually thereafter. Phase II allowances will be issued according to a complex set of provisions based, generally, on multiplying an emission rate of 1.2 #/mmBtu by the unit's baseline (average 1985–87) heat input.

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[9] SO_2 emissions can alternatively be reduced by switching to a fuel with lower sulfur content—generally coal, but potentially also natural gas or petroleum products.

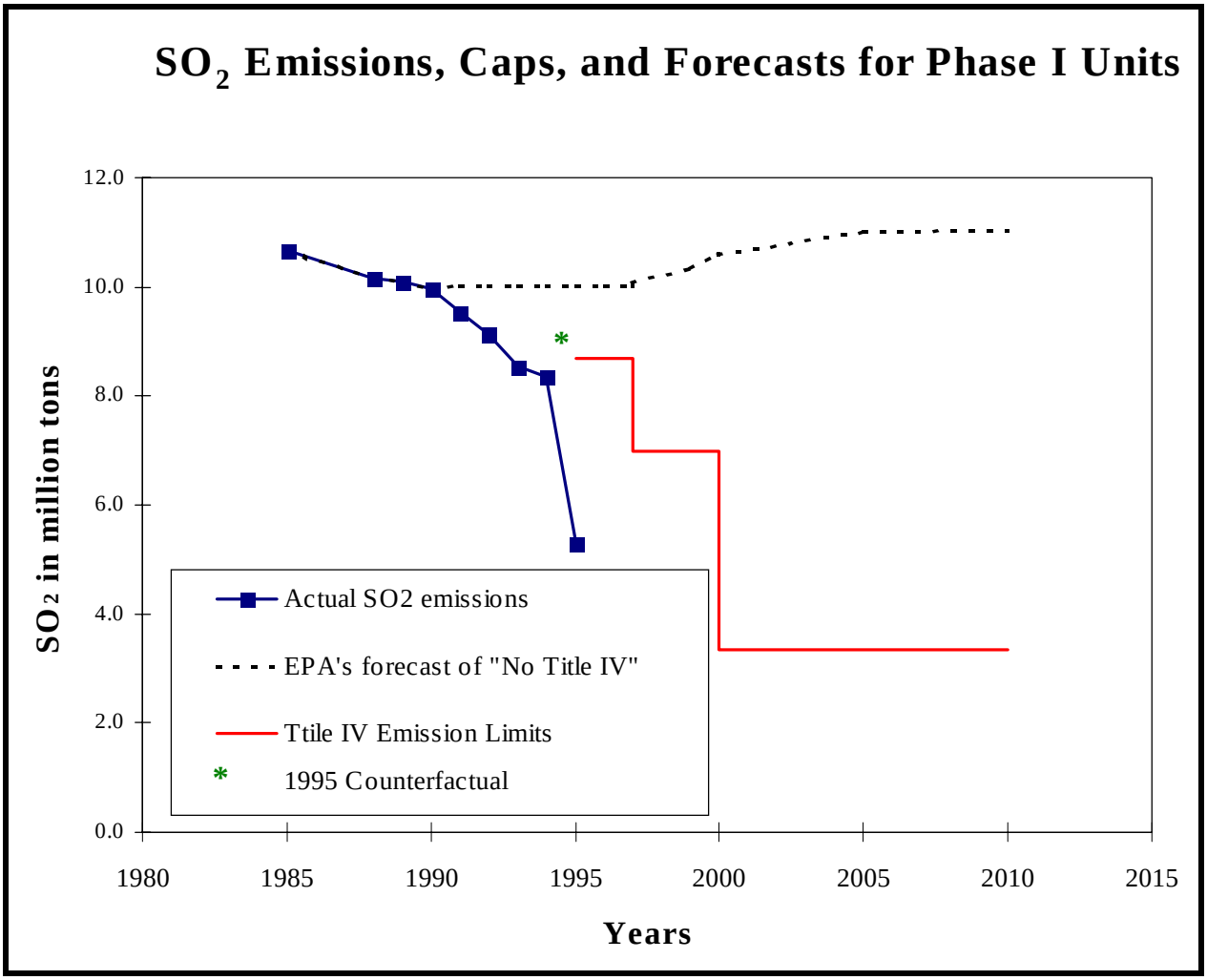
[10] See Montero (1997a) for a thorough description and analysis of the effect of these provisions.

[11] Atkeson (1997) provides an analysis of the reasons for the low participation rate by industrial sources.

III. REDUCTION OF SO_2 EMISSIONS THROUGH 1995

The most significant fact about Title IV compliance in 1995 is the magnitude of *over*compliance. The aggregate cap required that SO_2 emissions from Phase I-affected units be no greater than 8.7 million tons in 1995. In fact, emissions from those units that year totaled 5.3 million tons—3.4 million tons, or 40%, less than the aggregate limit.

Figure 1



Source: Derived from Pechan (1995), EPA's EMS and ATS, and EPA (1996b).

The essential statistical details of compliance are presented in **Figure 1** and **Table 1**. Figure 1 compares actual aggregate emissions from all Phase I-affected units in 1995 and earlier years with the Title IV-mandated caps in 1995 and subsequent years, and with earlier expectations of emissions trends in the absence of Title IV.[12] More detailed statistics concerning emissions at Phase I-affected units are presented in Table 1, which further distinguishes between those units mandated to be part of Phase I by Table A and those that voluntarily became subject to Phase I as a result of the substitution and

Table 1. Statistics of Phase I Units

Variables	Table A Units	Substitution Units[a]	Total Phase I
# Units	263	182	445
Total Capacity (MW)	88,007	41,643	129,650
Coal-Fired Units	257	154	411
Units with Scrubbers before 1990	1	25	26
Units with Title IV Scrubbers	26	0	26
Permanently Retired Units	7	6	13
Baseline8587 (10^{12} Btu)	4,365	1,740	6,105
Total Heat Input 93 (10^{12} Btu)	4,396	1,719	6,115
Total Heat Input 95 (10^{12} Btu)	4,708	1,932	6,640
SO2 Emissions 1985 (mm)	9.30	1.38	10.68
SO2 Emissions 1993 (mm)	7.58	0.97	8.55
SO2 Emissions 1995 (mm)	4.45	0.85	5.30
Average SO_2 Rate 1985 (#/mmBtu)	4.24	1.58	3.48
Average SO_2 Rate 1993 (#/mmBtu)	3.45	1.13	2.80
Average SO_2 Rate 1995 (#/mmBtu)	1.89	0.88	1.60
Basic Allowances (10^6)	5.55	0	-
Extension Allowances (10^6)	1.35	0	-
Early Reduction Credits (10^6)	0.31	0	-
Substitution and Compensating (10^6)	0	1.33	-
Total 1995 Allowances (10^6)	7.22	1.33	8.55
1995 Auction (10^6)	-	-	0.15

a. Includes 7 compensating units.
Source: Pechan (1995), EPA's Emissions Monitoring System (EMS) and Allowance Tracking System (ATS).

[12] There exists no forecast from 1990 of emissions from what would become the 445 Phase I-affected units in 1995. The illustrative forecast in Figure 1 is obtained by scaling an earlier EPA forecast (Pechan, 1995) concerned all electric utility generating sources to the proportion of emissions attributable to the 445 Phase I-affected units in 1990.

compensation provisions. The sharp reduction of SO_2 emissions in 1995 to a level well below the newly instituted cap is not the only notable feature about SO_2 emission trends since the passage of Title IV in 1990. Sulfur dioxide emissions did not rise after 1990 as had been predicted at the time the legislation was passed. By 1993–94, SO_2 emissions from generating units that would become subject to the 1995 cap approximated that limit. While less dramatic than the drop in emissions during 1995, the still unexpected emissions reduction prior to the onset of Phase I raises the important question of whether it resulted from the Title IV enactment or from other independent factors.

A. Pre-Phase I Reduction in Emissions[13]

The pre-1995 reduction in SO_2 emissions is particularly interesting because few Table A units were required by other regulation to reduce emissions prior to 1995, and no cost-minimizing firm would be expected to incur the additional expense associated with such a reduction unless required to do so.[14] Since SO_2 emissions from electric utilities had been declining throughout the 1980s despite rising coal use, it is possible this trend continued into the 1990s, though emission forecasts circa 1990 predicted otherwise. The pre-1995 reduction might also be explained by early compliance if regulated electric utilities were assured of cost recovery for the additional expenditures required by Title IV. In fact, this explanation is suggested by the fact that all SO_2 emissions reduction between 1990 and 1993[15] occurred at Table A units; this statement, however, is equally valid for the reduction in emissions observed between 1985 and 1990—before Table A was created for the Title IV enactment. A distinct pattern is also observed in the geography of emissions reductions between 1985 and 1993: almost all occurred in Midwestern power plants 600–1000 miles from a remarkable low-sulfur-coal-producing district, the Powder River Basin (PRB), located in the northeastern corner of Wyoming and adjacent counties of Montana. Most coal-fired power plants in this 600–1000-mile zone are Table A units. That similarly located non-Table A units also reduced emissions, while Table A units located further east did not, suggests that early compliance does not explain a significant amount of the pre-1995 emission decline.

The key to the real explanation for the phenomenon is the effect of railroad deregulation on access to this exceptional coal-producing province by Midwestern utilities. Coal from the PRB enjoys the lowest production cost and lowest sulfur content of any coal in America: extraordinary geology permits the mining of coal with a sulfur content ranging from 0.5 to 1.2 #/mmBtu for less than $0.25/mmBtu

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[13] This section summarizes Ellerman and Montero (1996), to which the reader is referred for a more complete discussion.

[14] Several states passed legislation requiring some form of early compliance, and a few units became subject to revisions in State Implementation Plan (SIP) limits; however, very little of the two-million-ton, pre-1995 reduction observed at Table A units occurred in these states or in units subject to SIP revisions.

[15] The year 1993 is a more appropriate reference point for gauging the pre-Phase I reduction than 1994 because fuel choice (and thus emissions) in 1994 were affected by preparations for compliance with Title IV.

(equivalent to $1.50 per barrel of crude oil). The astonishingly low cost and low sulfur content would be a winning combination except for geography: the northeastern corner of Wyoming offers little demand for coal, and the major potential markets lie far away. The cost of transporting PRB coals to major markets in the Midwest or Texas significantly erodes the mine-mouth cost advantage: the delivered coal price can be three to five times its mine-mouth price, depending on distance and transportation arrangements.

Railroad deregulation during the 1980s introduced competition into the haulage of coal from the PRB, and also led to significant productivity improvements in rail transportation. The result has been continually lower rail rates that have made distant western coals, primarily from the PRB, more competitive in Midwestern markets solely on a Btu basis, without regard to the significant difference in sulfur content.[16] As a result, the frontier for western, low-sulfur coals has advanced steadily eastward to the disadvantage of local, higher-sulfur Midwestern coals. Long-term supply contracts signed in the 1970s and early 1980s have delayed the switch to PRB coals; however, as these contracts have expired and economics have become more compelling, the share of PRB coals in the Midwest has increased steadily. One consequence has been reduced SO_2 emissions as the economic frontier for lower-sulfur western coals has penetrated regions in which many Table A units are serendipitously located.

B. Counterfactual Emissions

Evaluation of the effect and cost of Title IV requires some estimate of what SO_2 emissions would have been in 1995 had Title IV never been passed. Such a reference point is called a "counterfactual"—a concept very different from actual emissions in some earlier year. For instance, SO_2 emissions from Phase I-affected units declined by 3.25 million tons in 1995 from the 1994 level, so this might be considered one measure of the emissions reduction that could be attributed to Title IV. Yet, demand for sulfur-emitting fuels to generate electricity increased between 1994 and 1995, so such a measure would understate the true magnitude of the emissions reduction effected by Title IV. Conversely, the effect of Title IV would be overstated to the extent that SO_2 emissions declined for other reasons, such as increased reliance on non- or lower-sulfur-emitting fuels, or because of other regulatory requirements. Clearly, if the reduction in emissions attributable to Title IV is to be measured properly, a reference level of emissions is needed that takes non-Title IV-related factors into account.

One reasonable, though imperfect, counterfactual estimate can be formed by summing the products of the 1993 emission rate and 1995 heat input for every Phase I-affected unit. The 1993 emission rate reflects changes in SO_2 emissions not related to Title IV, while the 1995 heat input reflects actual demand for SO_2-emitting fuels in 1995. In effect, this estimate assumes that 1) unit emission rates would not have changed between 1993 and 1995 in the absence of Title IV, and 2) Title IV did not affect unit-specific heat input. Under these assumptions, SO_2 emissions would have increased as a result of the increase in demand for coal-generated electricity. This estimate of the counterfactual is indicated in Figure 1 by the single star that lies 540,000 tons above the 1995 emissions limit.

As with any estimate, potential for error exists. This counterfactual may be a little high because it assumes no units would switch to PRB coals after 1993 for reasons unrelated to Title IV, such as contract expirations and continuing reductions in rail rates; it also errs on the low side, however, by ignoring that

[16] The positive effects of railroad deregulation on costs and productivity are studied by Wilson (1997). The sharp decline of railroad coal transportation rates from PRB is reported in EIA (1995).

portion of the pre-Phase I emissions reduction in 1993 that can be attributed to Title IV.[17] A detailed simulation model of the electric-utility and fuel-supply sectors might provide a better estimate of emissions without Title IV; lacking that, however, we believe the errors in this expedient but transparent approach offset one another.

The assumption that heat inputs at Phase I-affected units were not influenced by the onset of Phase I is another potentially serious source of error. Surprisingly, there does not appear to have been any shifting of load to units not affected by Phase I. The 8.57% aggregate increase in heat input at Phase I-affected units between 1993 and 1995 was comparable to the 8.29% increase during the same time period for all electricity-generating units (including those not yet subject to Title IV limits), and statistical tests of data at the unit level did not indicate a significant difference between the utilization of Phase I-affected units and others in 1995 as compared to 1993.[18]

A clear difference exists, however, between heat input at units subject to Title IV that employed scrubbers and those that switched fuels: heat input at the Table A "scrubbed" units was 21.5% greater in 1995 than in 1993—well above the corresponding 5.5% increase for "switched" units.[19] The difference in heat input at scrubbed and nonscrubbed Phase I-affected units suggests that our estimation of counterfactual emissions could be incorrect, at least at the unit level, because Title IV appears to have influenced heat input among affected units, if not between affected and non-affected units. The most obvious alternative counterfactual assumption—that heat input would have increased in proportion with the 8.57% increase in heat input at all Phase I-affected units—is only 50,000 tons (0.5%) higher than the counterfactual we are using.

The reason scrubbed and unscrubbed units differed so markedly in their utilization during 1995 appears to be scrubbed units' lower *variable* cost of complying with Title IV. Unscrubbed units pay the cost of an allowance *and* the equivalent coal premium for lower sulfur content, while scrubbed units incur *only* the operating cost of scrubbing—which has been (and, we believe, always will be) lower than the cost of allowances. The differential impact of compliance with Title IV on utilization may also explain the absence of a shift in load dispatch to generating units not affected by Phase I. Units that could be expected to benefit from a shift in dispatch away from affected units are located in the same regions as the affected units, and, based on the criteria for selection of Table A units, these "non-Phase I-affected" units use lower-sulfur coal than Table A units have, historically. To the extent that the onset of Phase I created a premium for the lower-sulfur coal that non-Phase I-affected units burn, and that these units were prevented by state implementation plan (SIP) limits or locational costs from switching to cheaper, higher-

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[17] Ellerman and Montero (1996) estimate that about 20% of the pre-Phase I reduction is attributable to Title IV-related causes such as state acid rain laws and Clean Coal Technology projects that led to the early retrofitting of several Table A units.

[18] Utilization of Phase I-affected units was one question posed in the MIT/CEEPR questionnaire; the only responses given were "about the same" and "greater utilization."

[19] This disparity is not the result of some peculiarity in the 1993 utilization of the comparatively small number of units that were retrofitted with scrubbers for Phase I. Heat input to these 26 units in 1995 was 27% higher than average heat input at the same units for the years 1988–94, while the increase in 1995 heat input over the 1988–94 average for nonscrubbed Table A units was 3%.

sulfur coals, their fuel cost was increased by Title IV, and the relative merit of dispatching to them diminished.

C. The 1995 Reduction in Emissions

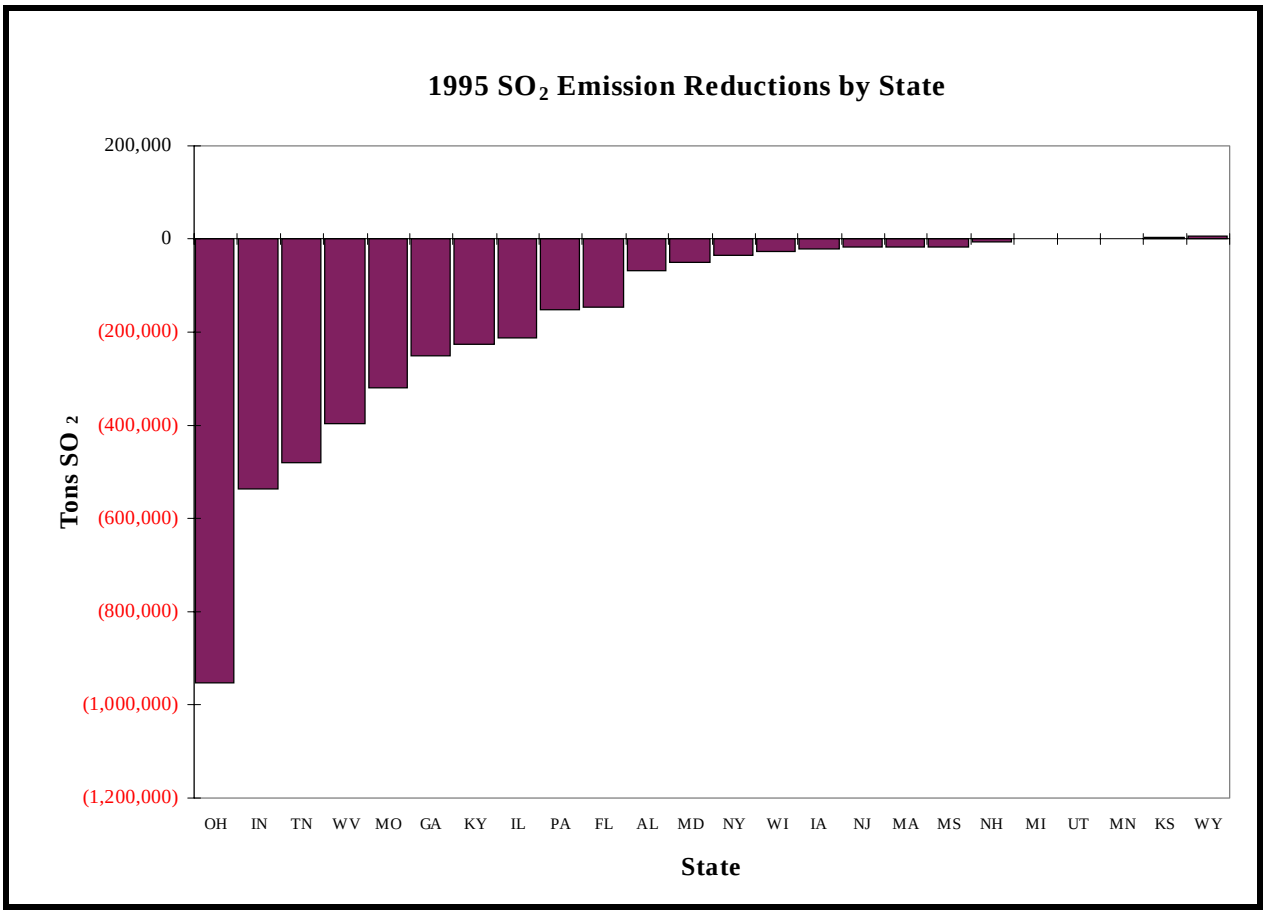
The aggregate emissions level attributable to Phase I-affected units in 1995 was 3.89 million tons less than the counterfactual for these units. This is more than the reduction in emissions observed between 1994 and 1995 due to the increase in aggregate heat input at these 445 units, but considerably less than would be indicated if the pre-Phase I reduction in emissions could be credited fully to Title IV. Whatever accounted for the pre-1995 reduction in emission rates, the 1995 reduction was significant and clearly attributable to Title IV.

TABLE 2. 1995 SO_2 REDUCTION AT PHASE I UNITS

Method/Region	Tons SO_2 Removed ($x10^3$)	% of Total
Scrubbing Total	***1,754***[a]	***45.1%***
New Title IV Scrubbers	1,734	44.6%
Other Scrubbers	21	0.5%
Switching Total	***2,133***	***54.9%***
Northern Appalachia	205	5.3%
Central Appalachia	756	19.5%
Southern Appalachia	60	1.5%
Midwestern	406	10.4%
Powder River Basin	518	13.3%
Other western coal	146	3.8%
Imported coal	22	0.6%
Natural gas	20	0.5%
TOTAL	**3,887**	**100.0%**

Source: Derived from EPA Emissions Monitoring System (EMS), EPA (1996b), Pechan (1993 and 1995), Federal Energy Regulatory Commission (FERC) Form 423, and Fieldston (1994).

Figure 2



Source: Derived from Pechan (1995), EPA's EMS and ATS, and EPA (1996b)

Much of the interest surrounding Title IV emissions reduction concerns the choice of abatement technique. **Table 2** attributes the reduction in SO_2 emissions at Phase I-affected units to the method used: scrubbing or fuel switching. In cases where fuel was switched, the source of the lower-sulfur fuel is indicated. Sulfur dioxide emissions can also be reduced through improved heat rates, conservation measures, or shifts in load to lower-sulfur- or non-sulfur-emitting generating units. Our method for measuring the reduction in sulfur emissions would not capture the effects of improved heat rates and conservation measures; however, the comparison of heat input at affected and nonaffected units suggests that these effects were negligible, as was load-shifting.

In aggregate, the 1995 emissions reduction was about evenly split between scrubbing and fuel switching, but the scrubbing contribution came from many fewer units. Only 26 of the 263 Table A units installed

scrubbers, though these account for 45% of the total reduction.[20] Two-thirds of the contribution from these 26 units, or 1.14 million tons, came from only seven units, at three big plants: Cumberland, Gavin, and Harrison.[21] These few units, totaling 7,200 MW^e, or slightly more than 5% of total affected capacity, account for almost a third of the 1995 emissions reduction from all sources throughout the country.

Powder River Basin coals continued to play an important role in reducing SO_2 emissions in 1995, but the main contribution to emissions reduction by fuel switching that year came from the bituminous coal-producing regions, particularly Central Appalachia. Notable among emissions reductions due to fuel switching is the contribution from units in the predominantly high-sulfur coal producing regions of the Midwest and North Appalachia that switched not to the 1.2 #/mmBtu coals available from such regions as Central Appalachia or the PRB, but rather to more local mid- or even high-sulfur coals that nevertheless contained less sulfur than the coal previously used.[22]

Geographically, the reduction occasioned by Title IV concentrated in the heavy coal-burning states of the Midwest. **Figure 2** shows 1995 reductions for the 24 states having Phase I-affected units. One quarter of the entire reduction occurred in Ohio; 90% occurred in the nine states extending from Pennsylvania and West Virginia west to Missouri and south to Tennessee and Georgia. There is also a decidedly more eastern cast to the 1995 reduction in SO_2 emissions compared to pre-1995 reductions. The states of Ohio, West Virginia, and Pennsylvania account for 40% of the 1995 reduction, whereas they accounted for none of the pre-Phase I emissions reduction, largely because they were then still east of the eastern frontier for western coals' effective market penetration.

The contribution of substitution units to the 1995 emissions reduction was small, despite their large number and the significant increase in generating capacity subject to Phase I restrictions. These 182 units account for only about 5%, or 213,000 tons, of the 3.89-million-ton reduction in 1995, though they represent almost a third of the generating capacity of Phase I-affected units. Although significant in number and aggregate capacity, their contribution to the 1995 emissions reduction was small because these units were less intensively used than Table A units, SO_2 emission rates at these units were lower initially (1.13 *vs.* 3.45 #/mmBtu for Table A units), and their reduction per unit of heat input was less (0.25 *vs.* 1.56 #/mmBtu for Table A units). More importantly, many of these units had already made emissions reductions relative to the reference year for the calculation of their allowance allocations—usually 1989–90.[23] As a result, substitution and compensation units received, in the aggregate, 243,000 allowances in excess of our estimate of counterfactual emissions for them.

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[20] Twenty-five units with scrubbers installed to meet new source performance standards (NSPS) became subject to Phase I as a result of the substitution provisions; their contribution to emissions reduction was small, however.

[21] These plants, located in Tennessee, Ohio, and West Virginia, are owned by the Tennessee Valley Authority, American Electric Power, and Allegheny Power, respectively.

[22] No definition of low-, mid-, or high-sulfur coal is universally accepted. In practice, any coal of 1.2#/mmBtu or less is considered low-sulfur, while any above 3.5#/mmBtu is high-sulfur. Mid-sulfur coals lie between these extremes.

[23] Allowances are issued to substitution units according to complicated and heavily litigated rules whereby average 1985–87 heat input for a unit is multiplied by the least of three emission rates for that unit: (1) the lower of the actual or allowable 1985 SO_2 emissions rate, (2) the greater of the 1989 or 1990 actual emission rate, or (3) the most stringent Federal or State allowable SO_2 emissions rate applicable in 1995–99, as of November 15, 1990.

From the standpoint of fuel suppliers and others (particularly in coal-supplying regions) whose livelihoods depend on the delivery of fuel to Phase I units, the number of tons of SO_2 reduced is of less interest than the change in the number of tons of coal delivered. It is noteworthy that the share of heat input from coal at Phase I-affected units was virtually unchanged (96.9% in 1995 *vs.* 96.6% in 1993). Although natural gas use at these units increased by 93 Bcf, this increase was entirely at the expense of oil, which declined by the equivalent of 123 Bcf. Coal use increased by 30 million tons, or the Btu equivalent of 530 Bcf. **Table 3** shows 1993 and 1995 coal deliveries from various coal-producing regions to Phase I-affected plants.[24]

TABLE 3. COAL DELIVERIES TO PHASE I PLANTS

(million short tons)

Coal Region	1993	1995	Change
Appalachia	**145.3**	**146.1**	**+ 0.8**
Northern	78.0	72.3	- 5.7
Central	63.0	69.7	+ 6.7
Southern	4.2	4.1	- 0.1
Midwest	**77.7**	**71.8**	**- 5.9**
Powder River Basin	**43.7**	**73.1**	**+ 29.4**
Other western	**15.5**	**20.4**	**+ 4.9**
Imported coal	**1.6**	**2.6**	**+ 1.0**
TOTAL	**283.8**	**314.0**	**+ 30.2**

Source: Derived from FERC Form 423.

Though virtually all of the increase in coal delivered to Phase I-affected plants came from the PRB, fuel-switching among the bituminous coal regions was also apparent. Deliveries from the predominantly high-sulfur regions of Northern Appalachia and the Midwest declined by 11.66 million tons from 1993 to 1995, or about 7.5%, while the lower-sulfur Central Appalachia and western bituminous regions

Originally, substitution units were to receive allowances based only on the 1985 emission rate; however, environmental groups brought suit against EPA to prevent issuance of "excess" allowances. This litigation led to the addition of the references to 1989–90 emission rates and other pre-Title IV limitations on 1995-99 emission rates, and effectively prevented issuance of allowances for reductions in the emission rate achieved between 1985 and 1989–90, as well as for any 1995–99 reductions otherwise required.

[24] A Phase I-affected plant is the site of at least one Phase I-affected unit.

experienced an increase of equal magnitude, 11.55 million tons. Since much of the 1995 reduction in emissions resulted from switching to lower-sulfur bituminous coals, these figures indicate that most of the reduction from switching among bituminous coals occurred within the same coal-producing region. To illustrate, if every switch from a high-sulfur to a low-sulfur bituminous region resulted in an average 2.0 #/mmBtu reduction in emissions, a net change of 12 million tons in coal deliveries in favor of the two low-sulfur regions would account for slightly less than 300,000 tons of SO_2 reduction. The total reduction in SO_2 emissions attributable to switching to bituminous coals is 1.6 million tons. The remaining 1.3 million tons reflects switching to lower-sulfur coals within the same supply region; of this amount, almost 45% took place within the high-sulfur regions of North Appalachia and the Midwest, and the remaining 55% was accomplished by units supplied by coals from Central and Southern Appalachia.

IV. SO_2 EMISSIONS TRADING UNDER TITLE IV

As noted earlier, the truly distinguishing feature of Title IV is its utilization of tradable emissions permits, or allowances, to achieve a 50% reduction in SO_2 emissions. Tradable permits and other market-based instruments have long been advocated as cost-effective means for achieving environmental goals, but the limited experience with emissions trading prior to 1990 was not particularly encouraging.[25] Consequently, it is not surprising there was considerable doubt whether this feature of Title IV would meet with any greater success than had earlier experiments with emissions trading.

Title IV embraces emissions trading with remarkably few restrictions. Allowances can be traded nationally, though the environmental problem being addressed is regional. No review or prior approval of trades is required so that, at least in theory, emissions trading could lead to regional patterns of emissions reduction that would exacerbate the problem being addressed (*i.e.*, create "hot spots"). The purchase and holding of allowances is not restricted to the utilities for whom these permits would become a necessary input for the generation of electricity from oil or coal. All sources receiving allowance allocations, as well as third parties, such as brokers and individuals, are free to buy or sell allowances with any other party. Neither the frequency nor the mechanisms for trading allowances are limited. Finally, a small fraction of the allowances to be issued to utilities (2.8%) are withheld and sold at an annual revenue-neutral, EPA-administered auction.

The boldness of Title IV's emissions-trading provisions offered little assurance to observers that this experiment would work. Some opposed the concept of emissions trading as wrong-headed, if not immoral.[26] The national press labeled the first publicly announced trades as the buying and selling of the "right to pollute."[27] Among those more favorably disposed, concerns focused not only on the effects of misinformed publicity, but also on the regulatory framework within which electric utilities operated: regulation, it was feared, would not provide utility managers with the incentive, or even the ability, to pursue cost-saving opportunities possible with emissions trading.[28] After the first EPA-administered auction in March 1993, the design and role of the auction joined the list of suspects responsible for too little trading and for allowance prices that were considered to be too low.[29]

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[25] See Hahn (1989) and Hahn and Hester (1989) for a review of the limited results as of 1989**.** The relatively small-scale programs employing tradable permits to phase-out lead and CFCs were successful, however, as discussed in NERA (1994).

[26] For instance, a cartoon titled "Tom the Dancing Bug," reprinted in the *New York University Law Review*, parodied emissions trading as equivalent to the issuance and exchange of licenses to murder. The cartoon originally appeared in *Funny Times*, September 1992, p. 23, published by Rubin Bolling.

[27] See, for instance, the *Wall Street Journal*, May 11, 1992, or the *New York Times*, May 12, 1992. A premature but typically pessimistic appraisal of the effect of the initial press coverage of the first publicly announced trade can be found in Malec (1993).

[28] Bohi and Burtraw (1991 and 1992).

[27] See GAO (1994), Cason (1993), and Cason and Plott (1996) for expressions of these concerns.

Before we turn to these concerns, it bears emphasis that no critical volume of allowance trading indicates a well-functioning market. Trading is necessary to realize the potential savings in compliance costs, but the theoretically optimal amount of trading depends on how the government initially allocates permits. If, by chance, permits were distributed such that the marginal costs of compliance at all units would be equal when their emissions were reduced to the amount permitted by allowances issued to each unit, no cost savings would be possible and there would be no reason to trade. The more allowances' allocation departs from such a distribution, the greater the cost savings possible by emissions trading, and the more trading is desirable. Furthermore, the optimal amount of trading will vary over time as the economics of dispatch and fuel supply alter marginal compliance cost at individual units.

A. Development of the Allowance Market[30]

One way to assess market development is by observing prices and trading volume. When transactions are few and information poor, prices show considerable dispersion, whereas, in a reasonably competitive market with good information, transactions are sufficient in number and frequency for a readily recognizable "market price" to become established, around which bids and offers cluster. **Figure 3** displays the pricing of "current vintage"[31] allowances from May 1992, when the first trade of an allowance was reported, through the March 1997 auction. These data were compiled from three sources: (1) trade press reports of prices at which some private trades took place, (2) cash, spot-market price indices for current vintage allowances, from three private market-making organizations, and (3) clearing prices from EPA's annual March auctions, from 1993 through 1997.

Few trades occurred before the first EPA auction in March 1993. Reports of parties actively seeking buyers and sellers for SO_2 allowances appeared in the trade press as early as 1991,[32] but not until May and July 1992 were the first bilateral trades reported—at prices of $265 and $300 per allowance.[33] The trade press reported other bilateral trading, but no additional price information for private transactions appeared before the first auction. Allowance prices in the May and July 1992 transactions approximated the estimates of Phase I allowance prices ($250-$350)[34] that served as buyers' and sellers' primary information prior to the auction.

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[30] This section draws heavily on Joskow, Schmalensee, and Bailey (1997), to which the reader is referred for more complete exposition of the arguments summarized here.

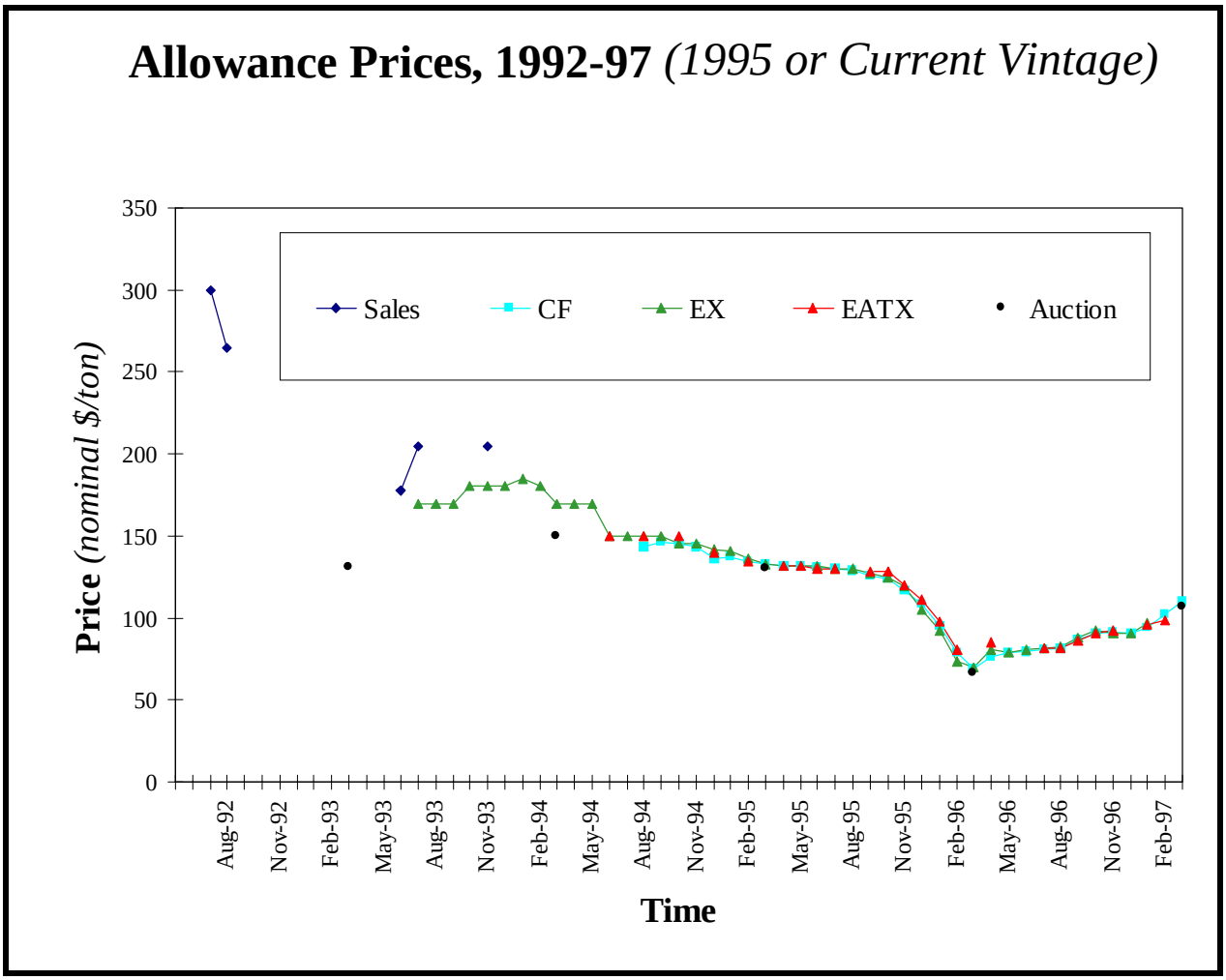
[31] The current vintage can be defined as those allowances that can be used to cover current emissions. The current vintage would have been 1995 through the first year of compliance, 1995. In 1996, the current vintage would be the 1996 vintage plus all banked 1995 vintage allowances.

[32] *Energy Daily*, May 15, 1991.

[33] Early reports of trades can be found in the *Wall Street Journal* (May 11, 1992, and July 1, 1992), the *New York Times* (May 12, 1992), *Energy Daily* (May 13, 1992 and July 1, 1992) and *Compliance Strategies Review* (various issues 1992–93).

[34] Prices for allowances in Phase II were projected in the $500-$700 range. See, for instance, ICF (1990) and Braine (1991).

Figure 3



Sources: Allowance Price Indications, 1993-97* - Cantor Fitzgerald Environmental Brokerage, NY, NY.
Compliance Strategy Review, 1992-97* - Fieldston, Washington, DC.
Exchange Value, 1993-97* Emission Exchange Corp., Escandido, CA.
*Selected Issues

Results of the first EPA-administered auction generated some controversy about allowance prices and the adequacy of emissions trading. Contemporaneous trade-press reports suggested utilities and intermediaries were surprised by the low prices: $131 for vintage 1995 allowances and $122 for vintage 2000 allowances. One utility characterized its purchase of allowances in that auction as "quite a bargain." [35] At the same time,

[35] Hoske, Mark T. (1993), "SO_2 Allowance Cost Falls to $122/ton in First EPA Auction," *Electric Power and Light*, 71(5), p. 3.

critics began to assert that shortcomings in the auction's design were biasing allowance prices downward.[36] The few private transactions reported subsequently, in 1993, appeared to support this criticism. In mid-1993, the Emissions Exchange (EX) began to report vintage 1995 allowance prices gathered confidentially from private parties; these prices remained at or slightly above $170 for the remainder of the year. A few more private transactions were reported, at prices of $178 and $205, during the summer of 1993, and the last newsworthy private trade was reported in November 1993, at a price of $205—significantly above both the EX price and the earlier auction price.

At the end of 1993, a clear, uniform market price would have been difficult to define from information then available; between mid-1994 and early 1995, however, various indicators of the market price for allowances converged. At the second EPA auction, in March 1994, clearing prices were $150 for 1995 vintage allowances and $140 for vintage 2000 and 2001 allowances. These prices were higher than the 1993 auction prices, but lower than prevailing EX prices—and still far below earlier projections of Phase I allowance prices. Soon after, in mid-1994, the EX price fell to the level established by the recent auction. At about the same time, two other third parties, Fieldston (EATX) and Cantor Fitzgerald (CF), began publishing allowance price information based on confidential private transactions. As Figure 3 makes evident, the prices reported by these three organizations were close. By the March 1995 EPA auction, convergence was complete: the auction clearing prices virtually matched what all three of these intermediaries were reporting as the private market price for allowances. The 1996 and 1997 auction clearing prices are also well in line with contemporaneous private spot-market transactions.

At the same time market price indicators for allowances were converging, trade activity was increasing significantly. No source reports the precise quantity of allowances traded privately, but a conservative estimate of arms-length, commercial trades can be made from the recorded movement of allowances between accounts in the EPA's Allowance Tracking System (ATS). The first two columns of **Table 4** report the number of private allowance trades recorded in the ATS for the twelve-month period preceding each auction, and the total number of allowances sold in that auction.[37] Although little private trading of allowances took place prior to the second EPA auction in March 1994, the volume of such trades increased greatly during the following two years. As of March 1997, about 11.8 million allowances had been traded privately, according to the ATS, compared to 1.1 million through EPA auctions.

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[36] See, for example, Cason (1993, 1995) and Cason and Plott (1996). The feature most criticized was the discriminatory price mechanism, whereby each successful bidder buys at his bid price rather than at the lowest winning bid price. The central argument for why the EPA auction mechanism would generate a downward bias in prices is that voluntary sellers have an incentive to set an artificially low reservation price, thus dragging down the auction clearing price. The validity of this line of reasoning rests on the absence of an efficient private market outside of the auction.

[37] To eliminate noncommercial transactions, all allowance transfers associated with special allocations (*e.g.*, bonus allowances made available for scrubbers) and trades involving generating units or accounts with common ownership were removed. Because there is no obligation to record trades until the holder desires to use allowances for compliance purposes, not all private trades are recorded in the ATS. Discussions with market participants lead us to believe that prompt recording of private trades was the rule in the early years, but increasingly, as the private allowance market has developed, allowances have not been moved into buyers' accounts until needed for compliance. Furthermore, there has been enormous growth in options, forwards, and other derivative trading, which would be invisible to the ATS until exercised so allowances are deposited in buyers' accounts.

TABLE 4. ALLOWANCES SOLD IN EPA AUCTIONS AND IN THE PRIVATE MARKET

	Number of Allowances Sold in EPA Auction	Number of Allowances Sold in the Private Market*	Total Allowances Sold
Through March 1993	150,010	130,000	280,010
April 1993-March 1994	176,200	226,384	402,584
April 1994-March 1995	176,400	1,466,996	1,643,396
April 1995-March 1996	275,000	4,917,560	5,292,560
April 1996-March 1997	300,000	5,105,924	5,405,924
Total:	**1,077,610**	**11,846,864**	**12,924,474**

* The number of allowances sold in the private market includes inter-utility trades, trades between utilities and third parties, and trades between two non-utility parties. This number excludes intra-utility trades (including intra-holding company trades), reallocations, and options to trade which have not been exercised.

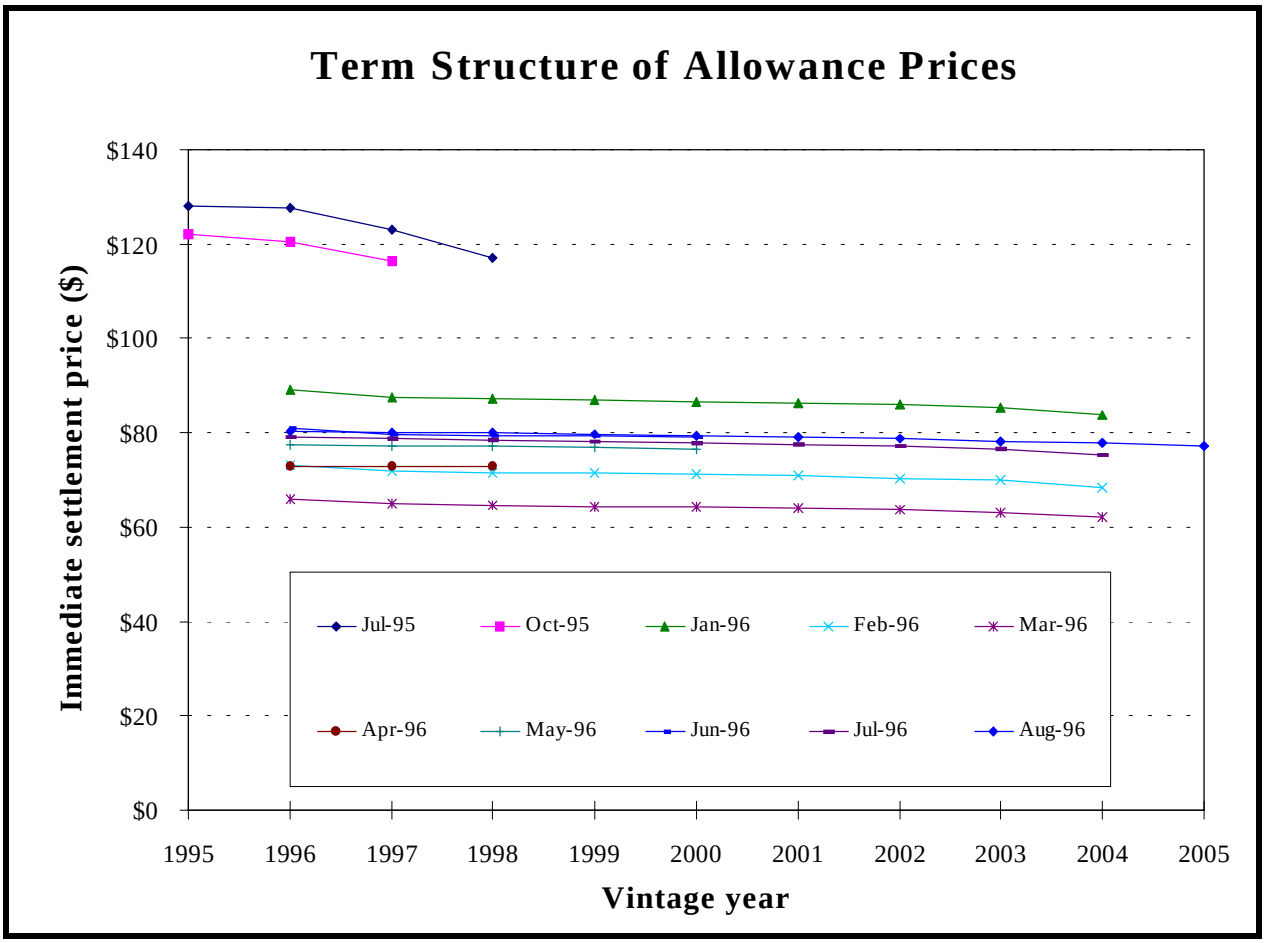
Source: Compiled by MIT/CEEPR from EPA's Allowance Trading System.

Since SO_2 abatement strategies generally involve investment and contracting decisions that affect emissions for many years, a futures market for allowances could be expected to emerge if utilities take advantage of opportunities for intertemporal cost savings made possible by the banking provisions of Title IV. In fact, this has happened, and the term structure of prices for current and future vintages suggests that the market for SO_2 allowances is liquid and effective. **Figure 4** presents the term structure of immediate settlement (not future delivery) prices for allowances of successive vintages from summer 1995 through early 1997. This pricing structure is "weakly backwardated," *i.e.*, current prices for immediate delivery of future vintage allowances are lower than the spot-market price for current vintage allowances.

Several reasons follow, from theory and the observation of other markets, to explain this pattern. Assuming banking across all relevant periods, in a world of certainty with no transaction costs, arbitrage between current and expected future compliance costs and between allowances of differing vintages would cause the immediate settlement prices for allowances of differing vintages to be equal, so the plots in Figure 4 would be flat.[38] In reality, uncertainty about the value of future vintage allowances imparts option value to currently usable vintages, and brokerage commissions add value (commonly termed the "convenience yield," in related contexts) to holding an allowance rather than selling one today and purchasing another tomorrow. Thus, in real markets with banking, where both uncertainty and transaction costs occur, the current vintage will cost more than future vintages—a difference in value

[38] In all periods, an individual holder of allowances chooses a level of SO_2 abatement such that the current marginal cost of abating in that period equals the current price of a spot-market allowance ($P_t = MC_t$). Across any two periods with banking, the individual will abate so that the discounted marginal cost of abatement is equal ($MC_t = MC_{t+1}$). Since the discounted marginal cost of abatement is equal across periods ($MC_t = MC_{t+1}$) and current marginal cost of abatement is equal to the current allowance price in every period ($P_t = MC_t$, $P_{t+1} = MC_{t+1}$), the immediate settlement prices for allowances of differing vintages would be equal ($P_t = P_{t+1}$). This also implies that the nominal price of an allowance should grow at the discount rate when banking occurs between period t and period t+1, *ceteris paribus*.

Figure 4



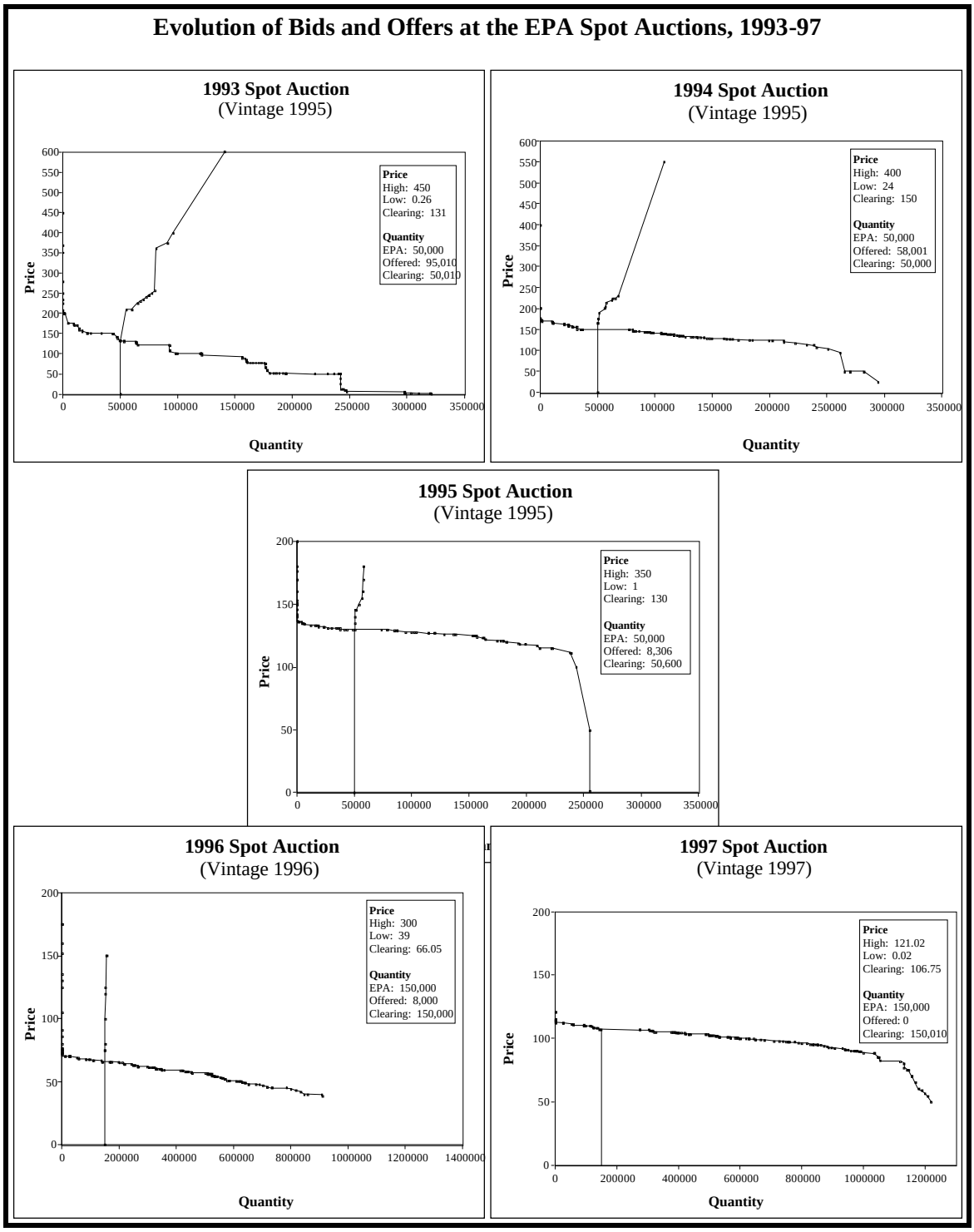
Source: Cantor Fitzgerald Allowance Price Indications, selected issues (1993-97). Cantor Fitzgerald Environmental Brokerage Services. NY, NY.

reflected by a weakly backwardated structure. Figure 4 demonstrates that the degree of backwardation diminished between the summers of 1995 and 1996. This flattening of the term structure may reflect the reduction in transaction costs,[39] increasing confidence in the value of future vintages, improved efficiency of spatial and intertemporal arbitrage as the allowance market has developed, or a combination of all three factors.

The development of an effective private market for allowances can also be seen in the dispersion of bid and offer prices in EPA auctions since 1993. In a well-functioning market with low transaction and

[39] As noted in Joskow, Schmalensee, and Bailey (1997), brokerage fees—one example of a transaction cost—fell from around $1.75 per allowance in 1994 to about $1.00 per allowance in August 1996, for each side of the transaction.

Figure 5


Evolution of Bids and Offers at the EPA Spot Auctions, 1993-97
1993 Spot Auction
(Vintage 1995)
Price
High: 450
Low: 0.26
Clearing: 131
Quantity
EPA: 50,000
Offered: 95,010
Clearing: 50,010
Price
Quantity
1994 Spot Auction
(Vintage 1995)
Price
High: 400
Low: 24
Clearing: 150
Quantity
EPA: 50,000
Offered: 58,001
Clearing: 50,000
Price
Quantity
1995 Spot Auction
(Vintage 1995)
Price
High: 350
Low: 1
Clearing: 130
Quantity
EPA: 50,000
Offered: 8,306
Clearing: 50,600
Price
1996 Spot Auction
(Vintage 1996)
Price
High: 300
Low: 39
Clearing: 66.05
Quantity
EPA: 150,000
Offered: 8,000
Clearing: 150,000
Price
Quantity
1997 Spot Auction
(Vintage 1997)
Price
High: 121.02
Low: 0.02
Clearing: 106.75
Quantity
EPA: 150,000
Offered: 0
Clearing: 150,010
Price
Quantity

information costs, little dispersion of bid and offer prices should be observed in auction, since there would be no point in bidding above—and it would be futile to bid below—the market price. **Figure 5** presents the supply and demand curves for 1995 or current-year allowances in EPA auctions from 1993 through 1997.[40] For the March 1993 auction, the buyers' offer curve shows considerable dispersion: a significant volume of allowances traded at prices well above the "market-clearing price" (*i.e.*, the lowest price paid), and a large number of "low-ball" bids are observed. The bid curve for 1994 is much flatter, and the number of allowance sales at prices significantly higher than the auction clearing price declined considerably. Finally, in 1995, 1996, and 1997, the buyers' offer curves are quite flat: few allowances have been traded at prices much above the market clearing price, and offers at very low prices are similarly few. The same narrowing in dispersion of auction bids is shown quantitatively by **Table 5,** which presents the percentage difference between the market-clearing price and the average price paid in each auction. While it would be hard to argue that bidders in the 1993 auctions had a good idea of the market-clearing price, it would be easier to make this argument for the 1994 auctions, despite the small number of private trades before March 1994. By the 1995, 1996, and 1997 auctions, a well-functioning allowance market had developed, so that prices bid in EPA auctions were determined by the outside, private market.

Table 5. Percentage Differences Between Average Winning Bids and Lowest Winning Bids in EPA Auctions

Year	Spot Auction	6-Year Advance Auction	7-Year Advance Auction
1993	20.6	-	11.5
1994	6.0	5.7	6.4
1995	1.5	2.3	1.6
1996	3.2	1.9	1.9
1997	3.4	0.3	2

Source: MIT/CEEPR based on EPA auction data.

Although the EPA auction was designed to stimulate development of a private market for allowances and to provide a source of allowances for new entrants, should no allowances be available through private

[40] The *demand* (or *buyers' offer) curve* is constructed by drawing, at a height corresponding to each bid price, a horizontal line with length corresponding to the associated bid quantity, starting with the highest bid price and working down to the lowest. On the supply side, the number of allowances offered for sale in the mandatory auction is represented by a vertical line at the relevant quantity on the horizontal axis. Since voluntary offers to sell in the EPA auction do not get matched with offers to buy until the mandatory offering is fully sold, the *sellers' offer curve* is completed by drawing horizontal lines at heights corresponding to the reservation prices for these voluntary offers and with lengths corresponding to the quantities offered at those prices, beginning with the lowest reservation price and working up to the highest. The intersection of the buyers' offer curve and the sellers' offer curve defines the market-clearing price, the lowest bid price at which allowances were purchased. Note that dots frequently appear on the vertical axis. These represent bids for very small numbers of allowances (often only one) submitted by individuals, environmental groups, law schools, and other noncommercial organizations.

transactions, the auctions' most important role may have been to establish visible market values. Buyers and sellers had little information about allowance prices when utilities were first planning for Title IV implementation, and the first EPA auctions provided important, if controversial, early data points concerning allowance values. At the time, it was thought that the discriminatory price feature of the annual auction might be creating a misleading downward bias, but later allowance prices in the private market and the auctions indicate otherwise. The expansion of trading volume, the convergence of price indicators, and the flattening of the buyers' offer curve in more recent auctions show that these later prices reflect a relatively robust market. Whatever the shortcomings in design of the annual EPA allowance auction, they did not adversely affected development of the market for SO_2 allowances. In fact, the EPA auction may have helped to form this market by providing a reliable indicator of market value at an early date. By establishing a structured, highly visible mechanism for revealing market value, the early EPA auctions provided a reliable and, as it turned out, more correct indication of allowance values than the few early trades and then-existing consensus among pundits. It is at least as plausible to argue that the few observed early non-auction prices were unduly influenced by consensus projections of allowance values that were too high as it is to argue that the early auctions created a permanent downward bias in allowance prices.

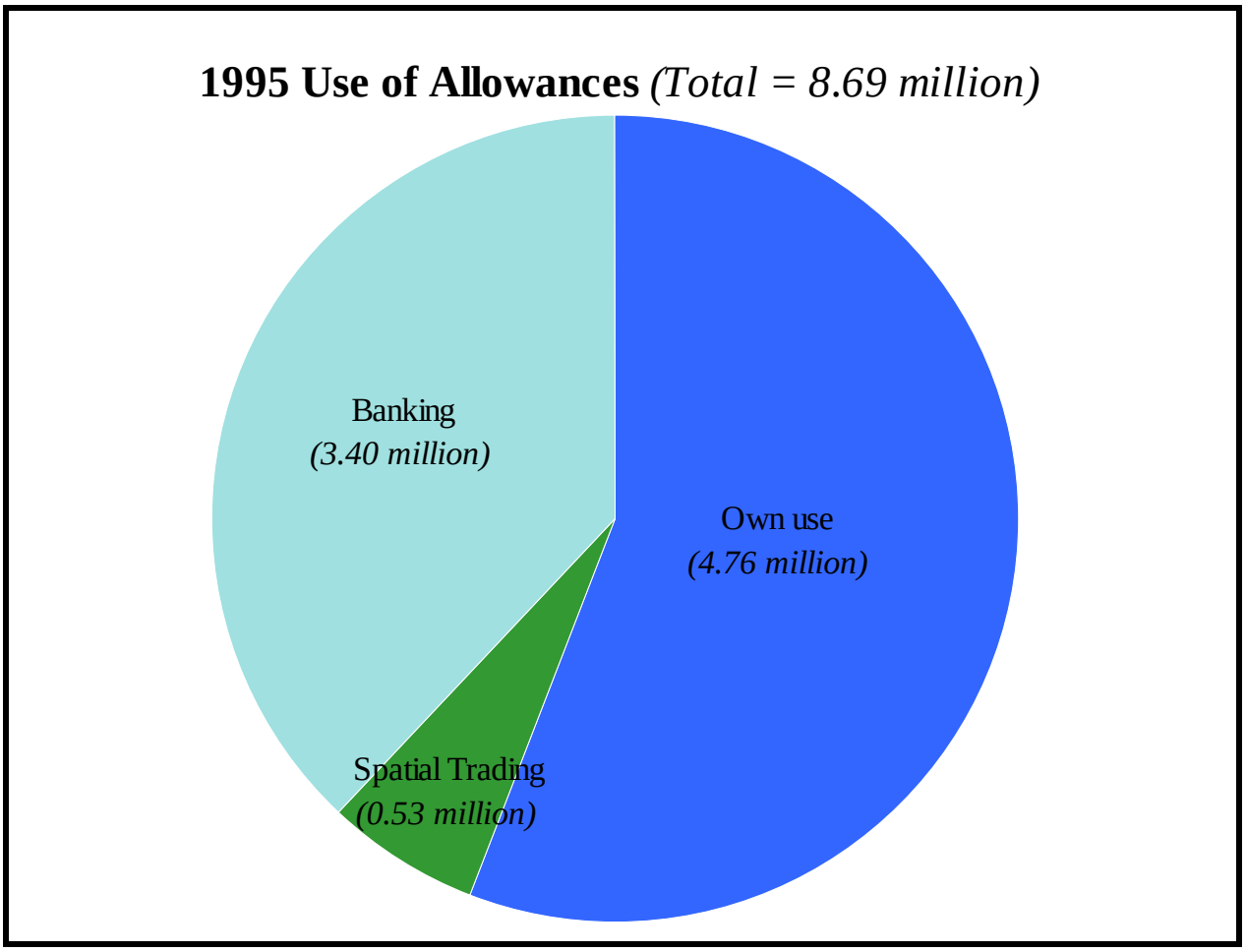
B. Use of Allowances by Electric Utilities

The cost savings possible with emissions trading are not limited to the arms-length commercial trading of allowances discussed in the preceding section. Utilities that reallocate allowances internally to shift compliance from affected units where abatement costs are high to units where abatement costs are low should be presumed to be saving costs as surely as if they were purchasing or selling allowances with third parties. Both forms of emissions trading—intra-utility as well as interutility—must be considered to assess the extent to which utilities have taken advantage of the flexibility afforded by Title IV to reduce compliance costs.

The use of allowances for compliance in 1995 provides a readily observable measure of the extent to which cost savings from emissions trading have been pursued. Of course, units whose 1995 emissions equalled the allowance allocation did not trade, and therefore showed no cost savings from emissions trading. Units whose 1995 emissions exceeded their allowance allocation obtained allowances from other accounts by internal transfer or by purchase from third parties. The number of allowances so obtained indicates the tons of emissions reduction avoided by emissions trading—presumably because any reduction would cost more than the allowances surrendered. Conversely, units whose 1995 emissions were less than the allowances issued to them had allowances available to transfer or sell to others or, alternatively, to bank for later use, transfer, or sale. The number of such allowances indicates the tons of emissions reduction incurred, presumably to free up allowances to sell or to avoid current or future emissions reductions.

Three basic uses for the 8.69 million allowances issued for 1995 are shown in **Figure 6**. The number of allowances used to cover emissions equal to or less than the initial allowance allocation to the 445 Phase I-affected units was 4.77 million, most of which were probably initially issued to those units. The wedge labeled "spatial trading" represents 534,000 allowances acquired by transfer or purchase to cover 1995 emissions greater than the allowance allocation at 98 Phase I-affected generating units owned by half

Figure 6



Source: Derived from EPA's EMS and ATS, and EPA (1996b).

(34) of the operating utilities with Phase I-affected units, located in 18 of the 24 Phase I-affected states. The wedge labeled "banking" represents 3.40 million allowances not used to cover emissions at any unit in 1995, but reserved instead for future compliance. Most of these (2.91 million) were retained by Phase I-affected utilities, but 0.29 million were sold to utilities not affected until Phase II, and 0.22 million were held in accounts maintained by third-party intermediaries—mostly brokers, but also fuel suppliers. In all, 3.95 million, or 45%, of all 1995 vintage allowances were used to reduce current or expected costs of compliance.

Early fears about the effect of state public utility commission (PUC) regulation on emissions trading focused on the extent to which state PUCs would allow utilities under their jurisdiction to transfer allowances to other utilities—particularly to those in other states. The effect of PUC regulation can be

Table 6. Allowance Transaction Activity by State, 1992-95 (All Vintage Years, Utility Accounts Only)

State	Allowances Purchased	Allowances Sold	Net Balance of Transactions
Alabama	63856	63260	596
Arizona	1901430	2248126	-346696
California	350084	130628	219456
Florida	689095	171715	517380
Georgia	2221010	2873109	-652099
Illinois	324290	173581	150709
Indiana	1170311	971824	198487
Iowa	3511	1725	1786
Kansas	29834	7038	22796
Kentucky	607594	620170	-12576
Massachusetts	12500	53000	-40500
Maryland	527621	215839	311782
Michigan	24500	16234	8266
Minnesota	15	15	0
Missouri	321579	389113	-67534
Mississippi	50859	23295	27564
Nevada	0	139636	-139636
New Hampshire	16378	8378	8000
New Jersey	555195	120626	434569
New Mexico	0	170738	-170738
New York	68777	190865	-122088
North Carolina	518153	35000	483153
North Dakota	6400	0	6400
Ohio	1499917	1994548	-494631
Oregon	299788	332930	-33142
Pennsylvania	9976742	5192210	4784532
South Carolina	348162	130674	217488
Tennessee	684964	870258	-185294
Texas	1604	102104	-100500
Utah	769126	75028	694098
Virginia	149841	114645	35196
Wisconsin	162514	227466	-64952
West Virginia	527918	5888305	-5360387
Wyoming	19340	611761	-592421
Total:	**23902908**	**24163844**	**-260936***

***This column does not sum to zero because the table only covers itself with purchases and sales by utilities. Purchases and sales made by brokers and other third parties are not included, nor is the sale side of the EPA auction transactions. The negative total net balance of transactions means that, on balance, utilities sold 260,936 allowances to third parties.

Source: Derived from EPA Allowance Tracking System

TABLE 7. NET ALLOWANCE TRANSFERS BY STATE

	States with Phase I Utilities	States With Only Phase II Utilities	Total
"Buyer"	13	5	18
No Net Change	1	13	14
"Seller"	10	5	15
Total	**24**	**23**	**47**

Source: Derived from EPA Allowance Tracking System.

assessed by examining the transfer of allowances in and out of accounts in the Allowance Tracking System and determining whether the pattern is affected by state regulatory procedures. [41] **Table 6** presents allowance transfers, by state, for all vintages between 1992 and 1995, and **Table 7** summarizes these data for the 47 Phase I and Phase II states, according to whether the net balance of transfers resulted in an increase ("buyer") or decrease ("seller") of allowances available to the state. [42]

Allowances were transferred among accounts in all states containing Phase I-affected units. The net effect ranged from zero for Minnesota to 4.78 million allowances acquired from out of state by utilities in Pennsylvania, and 5.36 million sold or otherwise transferred out of West Virginia. Transfer activity was observed in ten of the 23 states with only Phase II utilities, with a net effect evenly split between "sellers" and "buyers"; in the aggregate, however, utilities in states with only Phase II units have been net "buyers" (960,000 allowances "purchased" vs. 792,000 "sold"). Some of these transfers are known (through press report or auction result) to have been commercial transactions.

As discussed more fully in Bailey (1996), there is little evidence that state public utility commission regulation—or the lack thereof—has adversely affected electric utilities' decisions to trade. As of January 1996, only 15 state PUCs (of the 34 where allowance transfers have occurred) had explicitly addressed the treatment of allowances through issuance of a formal generic order and/or informal guideline, and in these states, PUC guidance is associated with a higher volume of transfer activity. More significantly, transfers have not been deterred in the 19 states where state commissions have yet to concern themselves with rate-making treatment for allowances. Queries to commission staff in all states without a generic order or informal guideline indicate that no guidance had been issued because no request for such had been received from utilities under their jurisdiction. While such response is an imperfect, and perhaps biased,

[41] Following the classifications and terminology developed by Bailey (1996), three broad types of allowance transfers can be identified: 1) administrative reallocations to conform the initial issuance of allowances to ownership and operating agreements concerning specific units, 2) economically motivated transfers among units owned by the same utility, and 3) arms-length commercial transactions among utilities. As we use the term, emissions trading encompasses the last two categories.

[42] Alaska and Hawaii are exempt from Title IV, and there is no sulfur-generating electricity production in the state of Idaho.

measure of the need for regulatory rulings, it does suggest that some utilities are comfortable trading without formal rules specifying how allowances will be treated for rate-making purposes. Increasing competitive pressures to cut costs, as well as regulatory lag and several incentive features that affect all operating costs, are likely stimulating cost-reducing emissions trading.

V. COST OF COMPLIANCE WITH TITLE IV

The evidence presented above does not suggest widespread reluctance on the part of electric utilities to avail themselves of the cost-saving flexibility afforded by the emissions-trading provisions of Title IV. In this section, we present an estimate of the cost to make the 3.9-million-ton reduction of SO_2 emissions in 1995, and compare that estimate with earlier predictions of compliance cost in 1995. We also examine the largest cost component—scrubbing—in more detail. Finally, we note an important ancillary cost of tradable permits: monitoring—specifically, the installation of continuous emissions monitors.

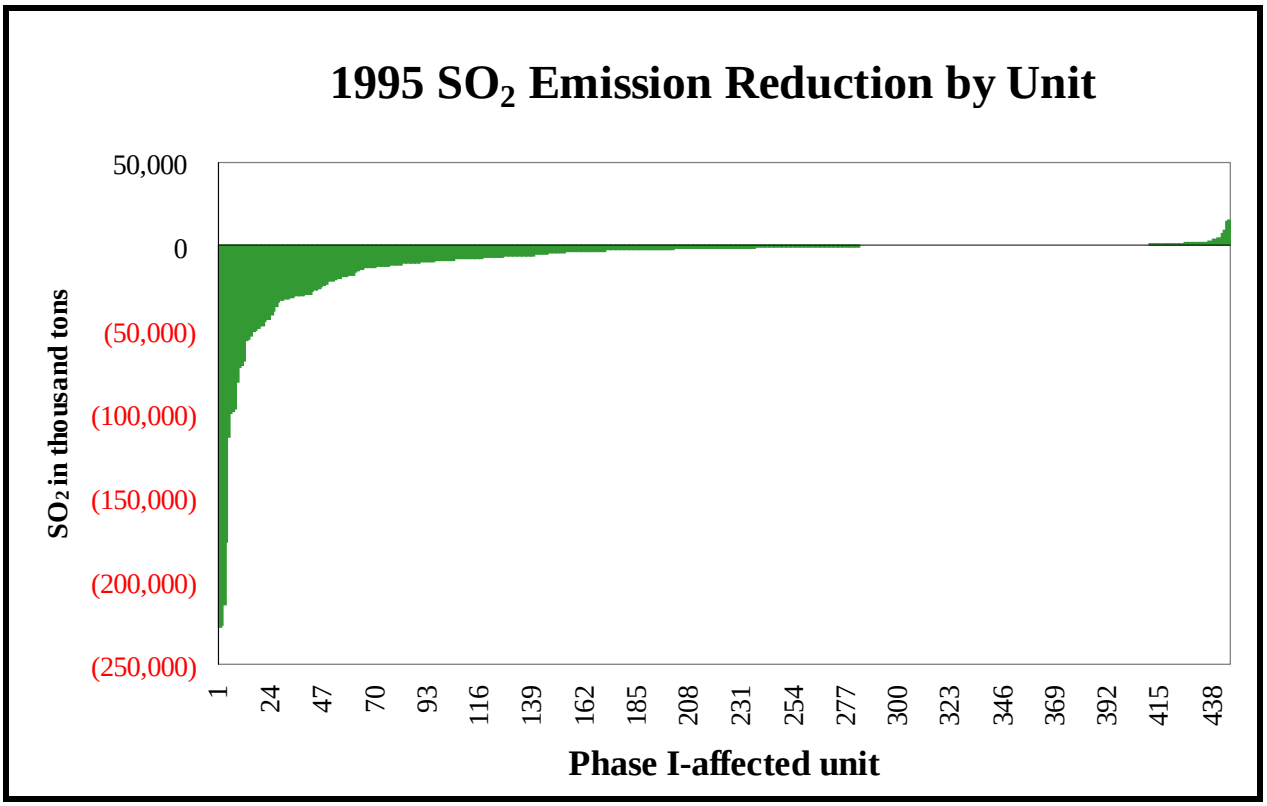
A. Total and Average Costs of Compliance

The main points concerning methods and data used to estimate compliance costs are summarized here; details are offered in the appendix. The cost of compliance is the additional cost incurred by generating units to meet new environmental requirements. This additional cost can be broken into two components: First is the annual capital charge for additional investment that will provide service in and after 1995 (examples are scrubbers and changes in boilers or coal-handling equipment to handle lower-sulfur coals). The second cost component is annually recurring operating or variable costs. For scrubbers, such operating costs include the costs of power to run the scrubber, of limestone or other reagent to absorb the SO_2, and of the disposal of wet or dry residue. Where fuel switching is the means of compliance, the principal variable cost is the extra expense for lower-sulfur fuel. Much of the data required to estimate cost are publicly available. In addition, we used responses to the confidential MIT/CEEPR survey of utilities to provide missing data, as well as to confirm the publicly available data and resolve ambiguities in the public data. When all else failed, we relied on interviews with plant and utility compliance managers to explain the intricacies of compliance at particular plants.

Identifying the cost of compliance at each of the 445 Phase I-affected units would be a formidable task; the task can be greatly simplified, however, because virtually all of the aggregate reduction in emissions can be attributed to about 40% of the units. In **Figure 7,** the 445 Phase I-affected units are arrayed by the magnitude of their reduction of SO_2 emissions in 1995. Starting from the right-hand side of Figure 7, the first 89 units actually increased emissions relative to the counterfactual; for the next 175 units (reading toward the figure's left side), individual unit reductions were small and, in the aggregate, approximately equalled the increase of emissions by the first 89 units. Most of these changes in SO_2 emissions resulted from the normal variations in utilization and fuel input that could be expected to occur at these units. The entire net reduction in 1995 can thus be attributed to the first 181 units from the left of Figure 7. Accordingly, in estimating the cost of the 3.9-million-ton reduction of SO_2 emissions in 1995, we ignore the 264 units that increased or only slightly reduced emissions.[43]

[43] Since fuel-delivery data is available only on a plant basis, the analysis is conducted on the basis of *all* Phase I-affected units at any plant where a Phase I unit reduced emissions by 5,000 tons or more. As a result, some Phase I units that showed little change or an increase in emissions are included. In the end, the analysis is based on 206

Figure 7



Source: Derived from Pechan (1995), EPA's EMS, and EPA (1996b).

The total annualized cost of the 3.9-million-ton reduction of SO_2 in 1995 was about $726 million, as shown in **Table 8.** The average total cost of compliance is between $187 and $210 per ton, depending on how units switching to lower-cost fuels are treated. The 425,000 tons of SO_2 emissions reduction labeled "No Cost PRB" denotes units that switched to a lower-sulfur fuel that was cheaper, on a total cost basis, than the higher-sulfur coal used formerly.[44] In some cases, the switching to cheaper PRB coals in 1995 was due to contract expirations; in other cases, however, the contract remained in place but appears to have been modified in response to Title IV, changing the coal source to the same company's PRB mine.

These estimates of the total and average total costs of compliance in 1995 are compared with earlier predictions of the emissions reduction and associated cost in **Table 9**. Our cost estimates are substantially lower than the first ICF Resources Incorporated (ICF) estimates, which assumed no trading, and the later Electric Power Research Institute (EPRI) and Government Accounting Office (GAO)

Phase I units at 70 plants that, in the aggregate, account for 3.89 of the net 3.94 million ton reduction of emissions.

[44] Almost all of this coal came from PRB; less than 3% originated in Colorado and Utah. Also, 4% of the "No Cost PRB" reduction is due to switching from oil to natural gas.

TABLE 8. 1995 COST OF COMPLIANCE WITH TITLE IV

Method	Reduction ($x10^3$ tons)	Total Cost of Compliance (Million $) Fixed	Variable	Total	Average Cost ($/ton SO_2)
Scrubbing	1,754	375.0	89.3	464.4	265
Switching	1,709	57.2	204.1	261.3	153
SUB TOTAL	**3,462**	**432.2**	**293.5**	**725.7**	**210**
No Cost PRB	425	0	0	0	0
TOTAL	**3,888**	**432.2**	**293.5**	**725.7**	**187**

Source: Derived from MIT/CEEPR Title IV Questionnaire (1996), FERC Form 423, EPRI (1993 and 1995; hereafter, EPRI93 and EPRI95, respectively), EPA Emissions Monitoring System (ongoing reports), EPA (1996b), Pechan (1995), Fieldston (1994), and Pasha (1993 and 1995).

TABLE 9. ESTIMATES OF PHASE I COMPLIANCE COSTS[45]

Source	'95 Emissions w/o CAAA	Title IV Reduction (million tons)	Total Cost (million '95$)	Average Cost ($/ton)
ICF89L (constrained)	16.64	3.56	871	245
ICF89L (flexible)	16.64	3.32	599	180
ICF90L (flexible)	16.64	3.12	573	184
EPRI93	16.29	4.36	1338	307
GAO94	9.37*	3.90	1163	298
EPRI95	14.65	3.18	894	281
Actual '95 (MIT)	15.70	3.46–3.89	726	187–210

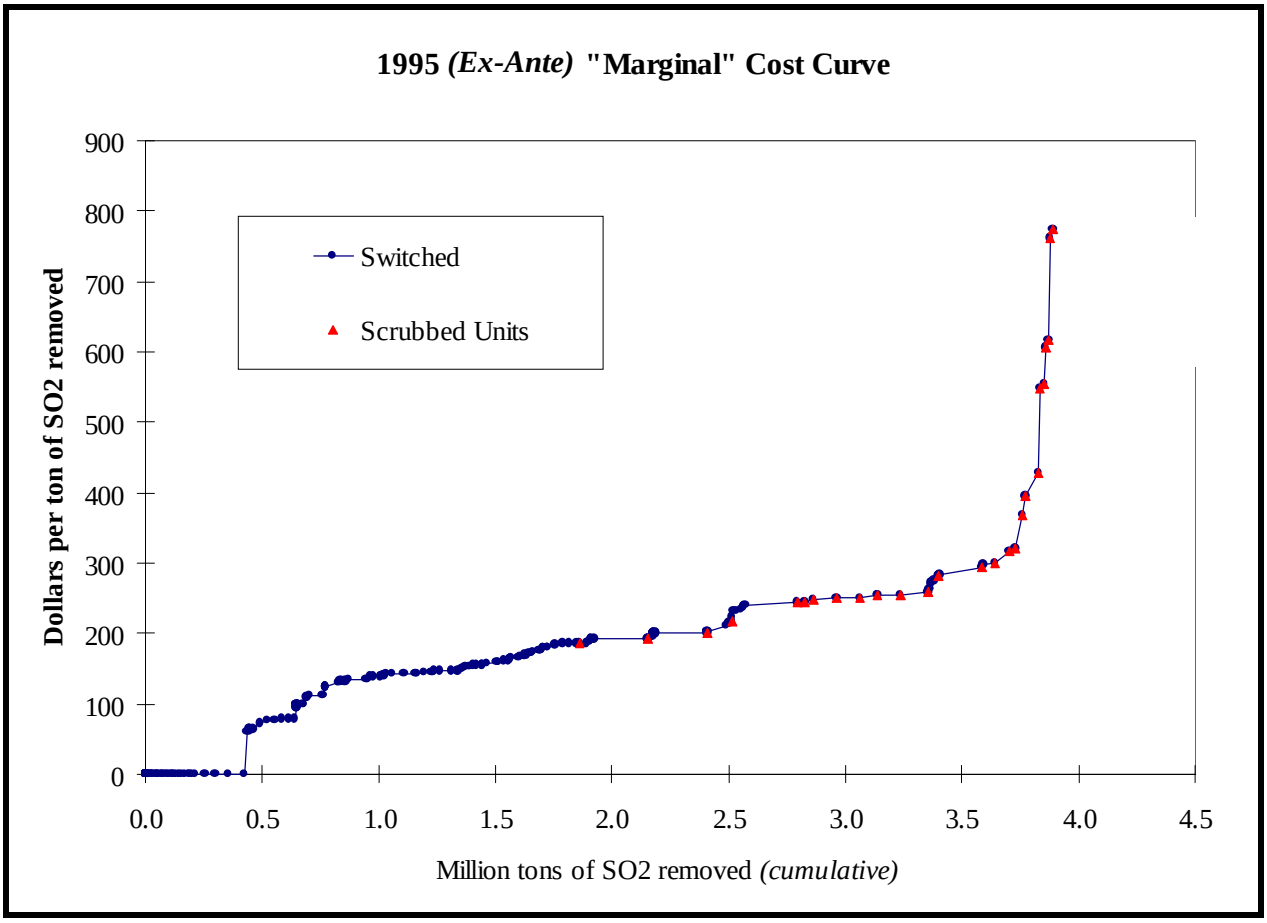
*Table A Only
Source: ICF (1989, Tables B1 and B5), ICF (1990, Tables B1 and B5), EPRI93 (Table C-1), GAO (1994, pp. 26 and 74), and EPRI95 (Table A-3).

[45] The ICF Low Base Case predictions are the only ones cited because they are closer to the actual growth in electricity demand between 1989–90 and 1995 and the amount of coal used to generate electricity in 1995. The ICF 1990 projection cited here is that for the Senate bill, which more closely approximated the final legislation than did the House bill. The ICF89 predictions of cost and emissions reduction do not include any banking, whereas all the other predictions do.

studies, which assumed limited trading, but our estimates are comparable on a per-ton basis with the 1989 and 1990 ICF studies that assumed flexible implementation (*e.g.*, relatively more emissions trading).

These comparisons must be used with caution. The cost data provided by these studies have been converted to 1995 dollars using the GDP deflator, but other incomparabilities cannot be so easily addressed. Earlier studies may have used a fixed annual capital charge based on a nominal interest rate, instead of an escalating capital rental price based on the real interest rate in 1995, as we have employed. In addition, we used a uniform lifetime of 20 years for all capital equipment in computing the depreciation component of the capital charge, while others, such as EPRI93, used a fifteen-year lifetime for scrubbers. Our assumptions yield lower capital charges, but a more definitive statement of differences in cost-estimating methods cannot be made without more detailed information than is provided by the earlier studies. Still, we believe it unlikely that differences in cost accounting would change the basic conclusion that the actual costs of abatement in 1995 have been at the lower end of what had been predicted.

Figure 8



Source: Derived from Pechan (1995), EPA's ETS and ATS, and EPA (1996b).

Another way of presenting the cost of compliance in 1995 is indicated by **Figure 8**, in which the 3.9-million-ton reduction in SO_2 emissions is arrayed by units' average total cost, in ascending order, based on 1995 utilization. Figure 8 approximates the national supply curve for Title IV compliance observed in 1995; it is not a "classic textbook" supply curve in that it includes mistakes and other departures from the most efficient, least-cost choices.

B. Cost and Performance of Scrubbers

The largest single component of compliance cost in 1995 was the interest and depreciation expense associated with the $3.5 billion investment in new Title IV scrubbers. Table 8 and Figure 8 clearly indicate that, on average, scrubbing has been a more expensive means of compliance than fuel switching; however, the cost of scrubbing has been considerably lower than predicted.

The average total cost of scrubbing in 1995—$265 per ton of SO_2 removed—masks great diversity among the units employing this abatement method. As indicated by Figure 8, the average total cost ranges from $189 to almost $800, reflecting variations among units in initial capital cost, utilization in 1995, and the amount of SO_2 removed per unit of heat input. The average initial capital cost for these retrofits is $249/KW^e, but the range varies by a factor of almost three, from $143 to $361. This variation in capital cost reflects variations in unit capacity, from 100 MW^e to 1300 MW^e, and in unit age, from 17 to 45 years of service as of 1995—and any other idiosyncratic features of the particular units being retrofitted. Eighty percent of this retrofitted capacity was brought on line between 1970 and 1975, and these units were among the last to be exempted from the new source performance standards imposed by the 1970 Clean Air Act Amendments.

Both ICF90 and EPRI93 provide sufficient data to compute expected average total cost for scrubbing as anticipated during the planning for Phase I compliance. **Table 10** compares the expected SO_2 removal cost for a representative retrofitted unit, using the predicted cost and performance data from ICF90 and EPRI93, with actual SO_2 removal cost based on the observed or calculated average cost and performance for the 21 scrubbed units that were fully operational in 1995.[46] The 21 fully operational Phase I scrubbers were removing sulfur at an average total cost of $282 per ton in 1995—about 60% of what had been predicted by earlier estimates.[47] The cost savings of about $180 per ton of SO_2 removed arises

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[46] The representative retrofitted unit in EPRI93 is a 300 MW^e unit with retrofit difficulty factor of 1.27. The unit is assumed to remove 90% of the sulfur from a 3.97# coal and to operate at a 65% capacity factor and gross heat rate of 9,722 Btu/kwh. ICF89 provides more complete cost data for scrubbing; that shown here is what would apply to the representative retrofitted unit used by EPRI93.

[47] This computation of average total cost is higher than that shown in Table 8 for two reasons. First, five units were excluded from Table 10, since their scrubbers were not operating from the beginning of the year. Second, Table 8 includes fuel savings assumed to result from shifts to cheaper, higher-sulfur coals by some retrofitted units, whereas these savings are not included in Table 10, which offers a comparison with earlier estimates that did not take such savings into account.

TABLE 10. SCRUBBER AVERAGE COST AND PERFORMANCE DATA

(1994 $)	ICF90	EPRI93	MIT/Actual
Basic Cost Data			
Initial Capital ($/KWe)	$ 249.00	$ 229.00	$ 249.00
Fixed O&M ($/KW-yr.)	$ 6.55	$ 8.19	$ 2.00
Variable O&M (mills/kwh)	$ 1.81	$ 2.24	$ 1.26
Performance Data			
Removal Efficiency (%)	90	90	94
Utilization (%)	65	65	83
Coal SO_2 (#SO_2/mmBtu)	3.97	3.97	4.14
Gross Heat Rate (Btu/kwh)	9722	9722	9800
Tons SO_2/MWe	99	99	139
Cost per Ton SO_2			
Capital Charge (@ 11.33%)	$ 285	$ 262	$ 203
Fixed O&M	$ 66	$ 83	$ 14
Variable O&M	$ 104	$ 129	$ 65
AVERAGE TOTAL COST	**$ 455**	**$ 474**	**$ 282**

Source: Derived from EPRI93, ICF (1990), MIT/CEEPR Questionnaire, and EPRI95.

from two factors: lower operating and maintenance (O&M) costs, particularly the fixed costs, and more intensive utilization of scrubbed units.

Let us consider O&M costs first. Based on responses to the MIT/CEEPR questionnaire, fixed O&M expenditure appears to be a third of what had been projected— or less—in the earlier ICF and EPRI studies. This finding was corroborated by subsequent queries to equipment suppliers and scrubber operators. The reduction in variable cost is not as dramatic, but at two-thirds of earlier predictions, the cost savings are still significant. The reasons for this cost reduction warrant further study, but explanations received from scrubber operators and equipment suppliers point mostly to reduced personnel costs, which show up as fixed O&M, resulting from both greatly improved instrumentation and controls on new scrubbers, and competitive pressures to cut costs. Variable O&M costs also appear to be lower than earlier projections because of the reduced requirement for power to run scrubbers as a result of the better controls, and some innovative sludge-disposal techniques, such as dry stacking.

The second factor leading to a lower average cost of scrubbing is higher utilization. In simplest form, the cost per ton of SO_2 removed by scrubbing is the amount spent per KW^e of capacity divided by the number of tons of SO_2 removed. In particular, higher-sulfur coal, better removal efficiency, and greater dispatch of the generating unit imply more tons removed per unit of capacity. In 1995, the sulfur content of coal and the removal efficiency were each a little higher than previously assumed, but the major difference was the significantly higher utilization of generating units to which scrubbers had been retrofitted. Heat input to the 21 scrubbed units that were fully operational in 1995 was 30% higher in 1995 than the average for the preceding seven years. A summary index of all these factors is indicated by the number of tons removed divided by MW^e capacity. The representative scrubber in EPRI93 was predicted to remove 99 tons per MW^e of retrofitted capacity; in fact, the 21 units on line for all of 1995 removed, on average, 139 tons of SO_2 per MW^e of capacity. The 40% increase in SO_2 removal per MW^e spread the capital and fixed O&M charges over more tons of SO_2 and led to a further reduction in the average cost of scrubbing.

If the operational experience in 1995 is any guide, the average total cost for scrubbing is not between $450 and $500 per ton of SO_2 removed, as was expected in the planning for Phase I, but about half this amount. The significant improvement in cost performance implies lower marginal cost of compliance in Phase II and, with a well-functioning allowance market that is arbitraging present and future compliance, lower allowance prices in Phase I.

C. Other Compliance Costs: CEMS

Every regulatory program incurs administrative costs that are usually not included in estimates of direct compliance cost. We have made no attempt to estimate the cost of personnel and equipment required to administer Title IV at electric utilities or at the EPA, but we do wish to highlight one element of the cost associated with Title IV: the requirement to have a continuous emission monitoring system (CEMS) on the stack of every affected unit. As its name indicates, a CEMS monitors flue gas emissions continuously, by means of electronic probes in the exhaust stack of generating units. These monitors are the basis upon which total emissions are measured for purposes of determining compliance and deducting allowances from unit accounts in the EPA's Allowance Tracking System.

The requirement to install continuous emissions monitoring systems at every coal-fired Title IV unit was controversial because CEMS are costly and may provide no better estimate of emissions than conventional methods. Prior to Title IV, most stacks did not have CEMS; emissions were estimated by a materials balance approach based on a sampling of fuel input that is performed routinely to ensure the quality of fuel delivered to the plant and to gauge the generating unit's operational performance. Although billions of dollars of coal supply transactions rely on the accuracy of commercial protocols for measuring in-fuel sulfur content, estimates based on these measures were not thought to be sufficiently trustworthy for emissions trading. For instance, an administrative adjustment would be required to account for sulfur retained in the bottom ash and for any sulfur reduction achieved by the use of additives or sorbents in combustion (as with fluidized beds) or in the exhaust stack (as with scrubbers). The effect of such factors is well-known based on engineering studies; however, assumptions are introduced inevitably not only about the effect at the particular generating unit, but also about operating conditions at the unit. In contrast, a CEMS provides a direct measure of emissions exiting the stack; getting from the CEMS observation to tons emitted, however, also requires a number of assumptions—concerning, for instance,

the homogeneity and velocity of the flue gas stream—that are arguably as problematic as those involved in the materials balance approach.

Whatever the comparative merits of the assumptions required to estimate emissions by the two approaches, a CEMS does reduce transaction costs by allowing operators to pursue flexible, cost-effective emission reductions without renegotiating the adjustments required by a materials balance approach to get from in-fuel sulfur content to SO_2 emissions. Although such adjustments could be renegotiated, the costs incurred to do so would dampen the response. Furthermore, without a CEMS, the regulator's relatively simple task of compliance—essentially matching recorded emissions with allowances—is complicated by more problematic requirements of ensuring that the indicated sulfur-reduction methods are indeed removing sulfur by at least the specified percentage. In effect, use of a CEMS separates the problem of estimating emissions from the operator's actions to control emissions.

Information concerning the capital and operating costs of CEMS was solicited in the confidential questionnaire that MIT/CEEPR sent to electric utilities as part of this research project. Responses were obtained from 130 Phase I units possessing 48,256 MW^e of generating capacity (29% and 37% of the respective totals for the number and capacity of Phase I-affected units). The total cost for these 130 units and the average cost per unit and per KW^e of capacity are reported in **Table 11**. Assuming these costs are representative of the whole, the additional cost of monitoring for Title IV in 1995 amounted to $48–54 million, depending on whether extrapolation is made by capacity or by the number of active Phase I units that installed CEMS that year (*i.e.*, 432).[48] At 7% of the observed cost of compliance, this extra requirement is noticeable, but not overwhelming; we provide no estimate of what alternative methods for monitoring emissions might have cost.

In the end, CEMS represents an additional administrative cost that may have encouraged more emissions trading and greater cost savings than would have been the case otherwise. Emissions trading requires low transaction costs and confidence that the tradable permit will be regarded as valid when presented for compliance. To the extent that CEMS has imbued the environmental regulator with sufficient confidence in the accuracy of emissions accounting to dispense with ancillary review and approval of emissions reductions, transaction costs have been reduced and greater emissions trading enabled. And, if more trading implies greater cost savings, as we believe it does, what began as political expediency may have proved to be a worthwhile investment.

[48] Subject to some exemptions for alternative measuring devices, Title IV also required that CEMS be installed by 1995 on all Phase II stacks as well as on Phase I stacks; 447 additional units, totaling 98.6 GW^e of capacity, will be subject to Title IV controls in Phase II, beginning in the year 2000. By the same methods of extrapolation described above, another $36–55 million in compliance costs were incurred by 1995 for Phase II monitoring.

TABLE 11. COST OF CEMS

Cost Category	Total ($x10^3$)	Per Unit	Per Kw^e
Initial Capital Cost	$ 92,135	$ 709,000	$1.91
Annualized @11%	$ 10,135	$ 77,227	$ .21
Annual Operating Cost	$ 6,080	$ 46,780	$ .16
Total Cost for 1995	**$ 16,215**	**$ 124,007**	**$ .37**

Source: MIT/CEEPR Title IV Questionnaire.

VI. WHY ALLOWANCE PRICES ARE SO LOW

One of the greater surprises in the implementation of Title IV has been the lower-than-expected price of allowances. While total costs, as we have seen, have also been on the low side of predictions, allowance prices have been much lower than the long-run marginal cost of abatement, which they would approximate in a well-functioning market at long-run equilibrium with reasonably good information and low transaction costs. Even more surprising, they are less than the average total cost of abatement which, in a world of efficient compliance decisions and varying abatement cost among units, would be lower than long-run marginal cost. As presented in Table 8 and Figure 8, the average total cost and the long-run marginal cost of abatement in 1995 were approximately $200 and $300 a ton, respectively; yet, since Phase I began, allowance prices have ranged from only $70 to $130.

Two explanations for the unexpectedly low allowance prices are frequently advanced. The first is that the disparity reflects serious imperfections in the allowance market, driven largely by defects in the EPA auctions. Like all real markets, the allowance market has not operated perfectly at all times. However, our analysis of its evolution strongly suggests that it evolved quickly into a well-functioning market with low transactions costs, price transparency, and extensive trading activity.

A second explanation for the gap between allowance prices and average abatement costs is that some utilities were forced by political pressures, reinforced by the utilities' status as geographic monopolies subject to cost-plus regulation, to invest in high-cost abatement technologies—in particular, scrubbers—which facilitated their continued use of local high-sulfur coal deposits, thereby helping to protect local businesses and jobs. Indeed, Title IV explicitly encourages the use of scrubbers through special bonus-allowance provisions. This type of behavior has two effects. First, it increases compliance costs above the "least cost" level and makes it difficult to identify a textbook "least cost" marginal compliance cost curve. Second, since scrubbers remove about 95% of the sulfur in flue gas, units installing scrubbers require many fewer allowances to cover emissions than they were issued for Phase I. Thus, "inefficient" scrubbing effectively increases the supply of allowances available for sale or banking for future use, and helps to drive down allowance prices.

Some of the investment in scrubbing has been driven by a combination of political pressures and subsidies provided by Title IV; however, we do not believe this is the primary explanation for low allowance prices. Many scrubbers that had been planned at the time Title IV was passed were subsequently canceled for economic reasons—including scrubbers in areas where there was substantial pressure to continue using local high-sulfur coal. Moreover, implementation of Title IV coincided with the introduction of public policies for increasing competitive pressures on traditional, regulated monopoly utilities. This in turn has increased utilities' reluctance to make long-lived investments that might not be recovered in a competitive market. We believe, instead, that the gap between allowance prices and observed average total and long-run incremental abatement costs reflects the fact that long-lived investments in compliance technology and long-term fuel commitments are made well in advance of compliance deadlines, while future allowance prices, fuel prices, abatements costs, and electricity prices are all still uncertain.

One of the two principal means of abatement under Title IV—scrubbing—is capital-intensive, and the contracting and construction lead time for placing a scrubber in service is two to three years.

Consequently, decisions to comply with Title IV by scrubbing required commitments in 1992–93, when information about allowance prices was not particularly good.[49] The economics of scrubbing may have looked relatively attractive in 1992, when allowance prices were expected to be $300 or higher. In retrospect, with allowance prices around $100 in 1995, the *ex ante* economics of building scrubbers are much less favorable; the capital is already sunk, however, and, with operating costs at about $65 per ton, the *ex post* economics of operating scrubbers are favorable. As a result, today's supply of allowances reflects past expectations about allowance prices, now embedded in irreversible investments.

The role of expectations in the choice to scrub is clearly indicated by responses to the MIT/CEEPR questionnaire. Respondents accounted for about half of the total retrofitted scrubber capacity. Of this group, operators representing 5000 MW^e of retrofitted capacity (75% of the retrofitted capacity operated by respondents) indicated that expectations of allowance prices of $300 to $400 were "very important" in decisions to scrub, which were made before the EPA auction in March 1993 offered the first signal that allowance prices might be significantly lower than expected. Responses also identified about 3600 MW^e of capacity for which scrubbing had been the initial—but not the final—choice; one-third of these responses stated that the initial decision was reversed due to "low allowance prices." [50]

Although fuel switching is generally a more flexible form of compliance, contracts can and do contain irreversible elements that operate analogously to those complicating investments in scrubbers. Any utility fuel manager planning to comply at a Phase I-affected unit by switching to lower-sulfur coal would be faced with the decision of whether to sign a contract prior to 1995 for low-sulfur coal supplies during part or all of Phase I, procure coal on the spot market, or some combination thereof. A premium would be paid for the lower-sulfur coal in either case, and the choice would be whether to lock in a premium (and the Btu value of the coal) in 1993 or 1994, or pay whatever the spot market required in 1995 and thereafter. Fears of "fly-ups" for low-sulfur coal prices [*cf.* ICF (1990), p. 37] and other uncertainties motivated many to sign contracts for low-sulfur coal in 1992–94 at the premiums then prevailing. Although such contracts do provide the buyer protection against price increases, they also prevent the buyer from taking advantage of lower-than-expected prices—in this case, purchasing less low-sulfur coal

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[49] For instance, it is now evident that there was a general failure to appreciate the extent to which switching to PRB coals for purely economic reasons would reduce the demand for abatement and increase the supply of allowances. In this regard, one key assumption in ICF's early studies of compliance cost deserves quotation in full: "These analyses assume that no subbituminous coals can be used in boilers designed for bituminous coals. However, many boilers in the Midwest have begun to experiment with subbituminous coals (either wholly or in blends), and this could be a low-cost emissions reduction option in many applications. As such, compliance costs ... could be lower than presented herein, and coal market impacts different. Recent analysis conducted by ICF Resources suggests that about 40-50 million tons of subbituminous coals could penetrate the bituminous boiler markets, largely displacing bituminous coal shipments from the West, but also displacing some Midwestern high-sulfur coal use." [ICF (1990), p. 36] As it turned out, 70 million tons of PRB coal were burned in Phase I-affected units in 1995.

[50] Among those who initially planned to scrub but decided otherwise, two-thirds stated that the decision was based upon a fall in low-sulfur coal prices relative to scrubber costs. The CEEPR/MIT questionnaire responses also make it clear that allowance prices were not the only consideration in deciding to retrofit a scrubber. One quarter of respondents with scrubbers stated that allowance prices were not an important consideration in the choice to scrub; for instance, one operator made the commitment to scrub prior to passage of the 1990 CAAA, as the result of a Clean Coal Technology Program award.

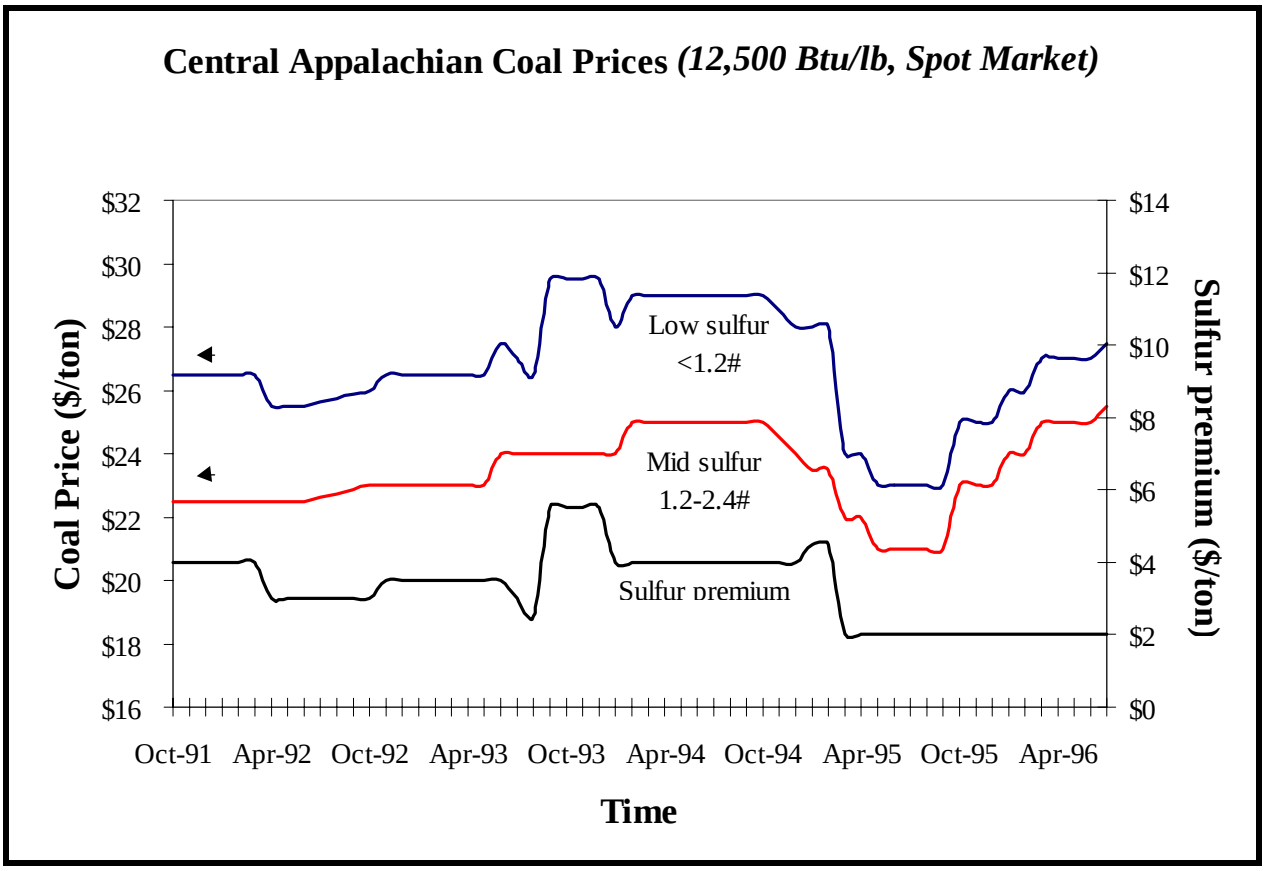
and using more allowances. As a result, the supply of compliance from such sources was, like that from scrubbers, more a reflection of price expectations when contracting and investment decisions were made than a response to prices realized *ex post*.

Many utilities subject to Phase I committed to abatement strategies by making investment and contractual decisions in the early 1990s based on expectations then prevailing about Phase I allowance and fuel prices. Looking forward from 1993, these decisions looked like they would be economical because allowance prices were expected to be much higher than what now appears to be their Phase I equilibrium level, and low-sulfur coal and transportation costs were expected to be higher than they have turned out to be. As time passed, allowance prices and abatement costs proved to be lower than expected, and alternatives to scrubbing now look much more attractive than they did when commitments to build scrubbers were made and long-term coal supply contracts were signed. However, once the investment and contractual commitments had been made, the supply of allowances from these sources was fixed, so that when the demand for allowances turned out to be less than expected, the current market was over-supplied. As a result, both short-run allowance prices and (because of banking) the trajectory of future allowance prices are below what they would have been, had investment and contracting decisions been made in a world where decision-makers had perfect foresight.

Evidence for the oversupply of abatement can be seen in the evolution of the premium paid for lower-sulfur coal in Central Appalachia, the main coal-producing region. The top two lines in **Figure 9** show the spot prices of low- and mid-sulfur coal, respectively, produced in Central Appalachia from late 1991 through early 1996. The bottom line—for which the value is plotted on the right-hand axis—is the sulfur premium: the difference in price between these two coals. The premium fell from $4/ton to $2/ton of coal at the beginning of 1995, when Title IV—and thus compliance with it—first came into effect. A reduction in the premium paid for lower-sulfur coal was not a predicted effect of Title IV, but it did reflect the balance of supply and demand for abatement in 1995: every dollar difference between the two coals shown in Figure 9 equates to approximately $65 of allowance value.[51] At the equivalent of an allowance price of $260, the coal sulfur premium during 1993 and 1994 was in line with earlier predictions of allowance value; when compliance became mandatory in 1995 and allowances were available at $130 and lower, however, it made no sense to pay $4 per ton of coal more for the lower-sulfur product. Suppliers of low-sulfur coal may have been hoping that the onset of actual compliance with Title IV would justify the expectation-based premium that existed prior to 1995; but that premium would be sustained only if allowance prices rose. When they did not, because there was more than enough current abatement being supplied at the existing allowance price, the absence of demand for low-sulfur coal left no alternative but to reduce spot prices for low-sulfur coal so that the difference between

[51] The prices in Figure 9 are representative for typical coals; the premium calculation for specific coals will differ. The Figure 9 premium calculation compares a 1.2#/mmBtu coal with a 2.4#/mmBtu coal. With 12,500 Btu/lb, each short ton of these coals would emit 30 or 60 lb SO_2, respectively ($12{,}500 \times 2{,}000 \div 10^6 \times 1.2$ or 2.4). Thus, for every ton of 1.2#/mmBtu coal burned in place of 2.4#/mmBtu coal, SO_2 emissions are reduced by 30 lb. Every dollar difference in the price of these coals is worth $67 in allowance value ($1.00 ÷ 30 x 2,000).

Figure 9



Source: Derived from Coal Outlook (several issues).

them and the spot prices of mid-sulfur coals was consistent with the value being accorded additional abatement by the (spot) allowance market.

In the short run, the price of an allowance reflects the current demand for and supply of abatement, given the investment in scrubbers and contract commitments.[52] Once capital costs are sunk, long-run cost is no longer relevant for existing scrubbers, which will be utilized so long as allowance prices cover operating costs. Indeed, given the magnitude of abatement supplied by scrubbers, the operating cost for scrubbing constitutes the effective floor for allowance prices.[53] Contracts for low-sulfur coal similarly limit the response to current price, but their influence is more limited, since contracts expire. In fact, the short-run

[52] About 70% of coal deliveries (in Btu) to Phase I plants in 1993 were under contracts lasting two to 20 years or more, and 67% for the case of Central Appalachian coals (FERC Form 423; Pasha, 1993 and 1995).

[53] We were informed that when allowance prices sank to around $70 in the first quarter of 1996, some scrubbers were pulled off-line for maintenance; other operators have told us they considered shut-down or actually reduced removal efficiencies.

marginal price of allowances is largely determined by the supply of and demand for abatement from uncommitted parties who have the flexibility to purchase or supply lower- or higher-sulfur coals as allowance prices and delivered costs warrant.

It is evident, *ex post*, that there has been overinvestment in abatement. Additional abatement can be supplied very cheaply in Phase I because of the now-sunk investment in scrubbers and their now-evident, lower-than-expected operating cost. When coupled with low-sulfur coal contract commitments, the supply of abatement in 1995 was more than enough to meet the 1995 emission cap. However, with current abatement so cheap, the demand for future abatement generated by Title IV's banking provisions has been sufficient to ensure that most unused allowances are reserved for later use. In effect, banking compensates for today's overinvestment by deferring the time when additional investment in abatement will be required.

Mistaken expectations assume a large role in explaining what we believe to have been overinvestment in abatement in 1995, but not all investment in scrubbers should be attributed to this cause. Various initiatives have been taken at the state level to encourage the building of scrubbers to protect local coal production, and Title IV itself provided significant incentives in the form of Phase I extension bonus allowances to build scrubbers during Phase I. Neither the bonus allowance provisions nor state initiatives can be considered unexpected developments, although it is possible that market participants did not adequately appreciate the extent to which the resulting supply of allowances would affect Phase I prices. Had predictions of future allowance values been more prescient prior to 1995, the disparity observed today between long-run and short-run marginal costs would not be so great because there would have been less investment in scrubbers and perhaps lower-volume contract commitments to low-sulfur coal. At the same time, it must be recognized that today's short-run marginal cost (and allowance price) would not have prevailed had there been perfect foresight. Had fewer scrubbers been built and lower-volume contract commitments to low-sulfur coal been made, the supply of abatement in 1995 would have been less and allowance prices higher.

All this suggests that the allowance and coal markets, like all real markets, are neither perfectly informed nor continually in long-run equilibrium. Were they so, allowance prices would have been higher and the average total cost of abatement in 1995 would no doubt have been somewhat lower. As we shall now argue, however, costs would most likely have been substantially higher had a market-based policy not been adopted.

VII. COST SAVINGS FROM EMISSIONS TRADING

Since the time Title IV was proposed, it has been generally accepted that emissions trading could reduce the cost of compliance, but questions of how much emissions trading would occur and what its impact on cost would be have generated considerable disagreement. The emergence of an allowance market, as discussed in Section IV above, indicates that electric utilities have been trading allowances. More specifically, the reconciliation of allowances and emissions, as shown by Figure 6, provides a precise measure of the importance of emissions trading in 1995: 45 percent of 1995 vintage allowances were used in a manner that implied cost savings from either spatial or intertemporal emissions trading. It can reasonably be assumed that the cost of the 534,000 allowances acquired by transfer or purchase to cover emissions in excess of the allowances issued to 98 Phase I-affected units was less than the cost of the emissions reduction thereby avoided. Similarly, it is likely that the 3.25 million allowances not used to cover emissions in 1995 were banked[54] in order to avoid future emissions reductions expected to be at least as expensive (when discounted) as the cost of any alternative use of those allowances. Setting aside the actual cost of acquiring allowances (which may have been zero), there was an opportunity cost: any allowance could have been sold in 1995 at a market price ranging from $109 to $138.

Further evidence of cost-saving emissions trading is provided by the extent to which the actual 1995 emission rate at affected units deviated from what it would have been, had operators not been permitted to trade allowances and been required instead to keep emissions within the allowance allocation for each affected unit. In such a case, one of two emission rates would be relevant for every affected unit: a "1995 allowance rate"—what would have been "permitted" by the allowance issuance to the unit, given 1995 heat input—or the counterfactual (1993) emission rate. Operators of units for which the counterfactual rate was higher than the allowance rate would have to reduce emissions to achieve the latter rate, while operators of units for which the allowance rate was not constraining would have no reason to change from the counterfactual rate. **Figure 10** arrays the 445 Phase I-affected units by the lesser of these two rates at each unit, and compares the resulting "no trading" emissions rate with the actual 1995 rate. Most units' actual rates deviate significantly above or below the "no trading" rate. Those with a higher 1995 emissions rate were mostly units short of allowances that found it cheaper to acquire additional allowances than to incur the cost of reducing emissions to match the number of allowances issued them. Conversely, for those units with a lower actual 1995 emissions rate, the value of additional allowances justified the *short-run* marginal cost of further emissions reduction. Although some change from the "no trading" emissions rate could have been expected as a result of normal variability in sulfur content, the magnitude and number of deviations observed strongly indicate that managers of Phase I-affected units were not taking the allocation of allowances to particular units as given. As Figure 10 shows, operators of most Phase I-affected units took advantage of emissions trading, presumably to reduce the cost of compliance with Title IV.

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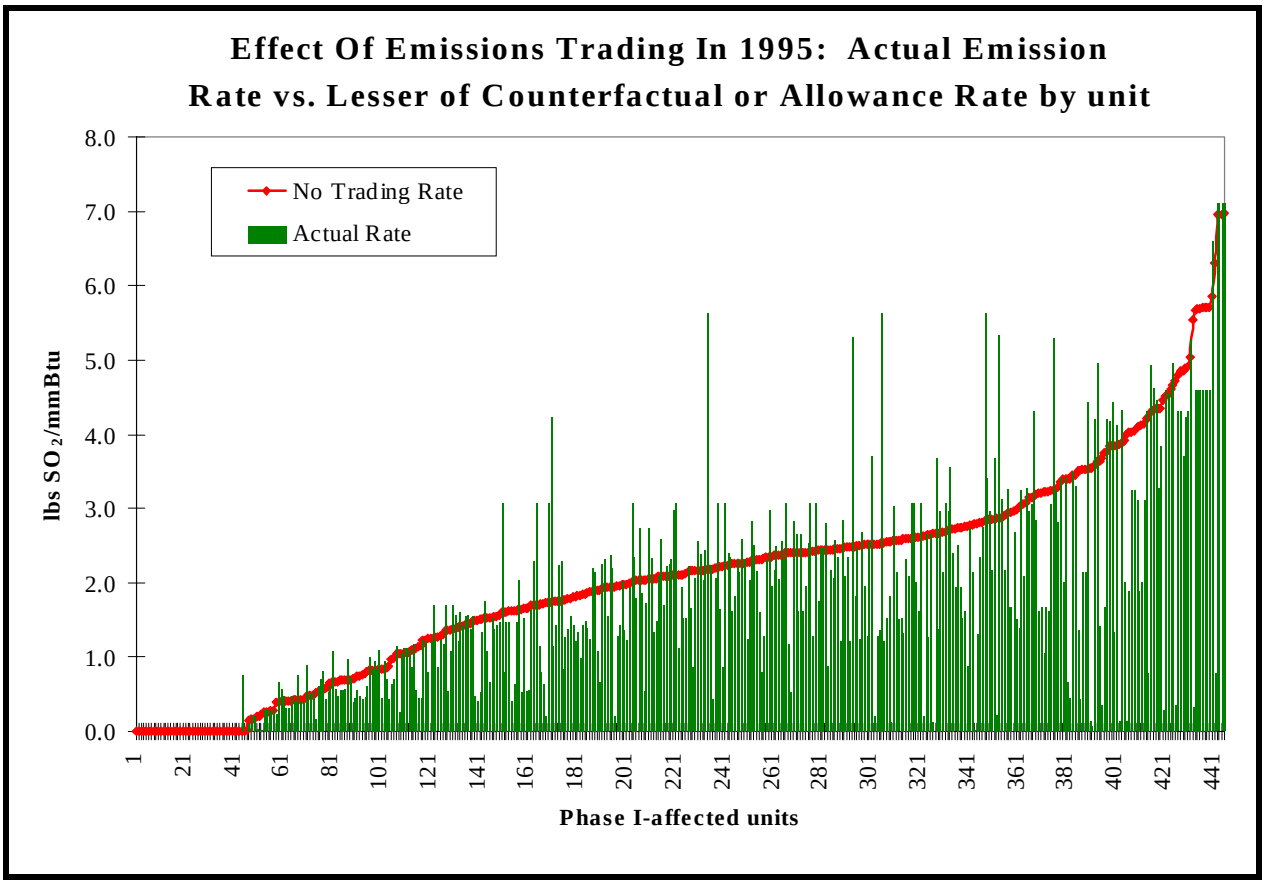
[54] This number includes only those allowances distributed to utilities in 1995. The total bank of 3.4 million allowances includes another 150,000 allowances sold through EPA auctions.

Figure 10



Source: Derived from Pechan (1995), EPA's ETS, and EPA (1996b).

Other evidence of cost-saving emissions trading can be found in the collapse of the sulfur premium in Central Appalachia. If utilities had not been equating the current marginal cost of abatement to allowance prices, there would have been no downward pressure on the coal sulfur premium in 1995. Utility coal-buyers would have continued to buy lower-sulfur coal at comparatively high premiums and continued to supply an increasingly glutted allowance market. Instead, arbitrage was effective between the paper (allowance) and real (coal) markets for sulfur removal, as buyers and suppliers of higher-sulfur coals realized that the higher-sulfur product bundled with allowances was a cheaper means of compliance than lower-sulfur coal at prices then being offered. The bundling of allowances with higher-sulfur coals (typically exceeding some contractually specified level, such as 2.5 #/mmBtu) has been frequently reported in the trade press; in fact, coal companies have established accounts in EPA's Allowance Tracking System to facilitate bundling.[55] The arbitrage between allowance and coal markets also

[55] Since the ATS was established in March 1994, accounts have been opened and maintained by Peabody Coal Company, Cyprus Amax Coal Sales Co., Canterbury Coal Company, Cooney Brothers Coal Co., Courney F. Foos

demonstrates that utility buyers are taking advantage of the cost-saving opportunities made possible by emissions trading. Furthermore, the bundling of allowances shows that, independently of utility actions, cost-saving compliance is being supplied innovatively by parties that otherwise receive no allocation of allowances to use for final compliance.

The behavior observed in 1995 provides compelling evidence that emissions trading has lowered costs of compliance, but does not indicate the magnitude of savings achieved. Earlier studies of compliance costs with Title IV have provided estimates of the potential savings, derived by both the differences in predicted costs between scenarios that assumed more and less trading, and variations among these studies in the amount of assumed emissions trading and in the corresponding costs:

- ICF's 1989 analysis predicted the cost savings for limited trading among utilities within the same state to be approximately $225 million (in 1988 dollars), about 33% of the predicted cost of compliance in the "less trading" case.[56] In addition, ICF89 estimated that banking provisions might result in an additional annual reduction of emissions in Phase I of between 0.8 and 1.2 million tons, resulting in a present-value cost savings of $150 million, about a third of the predicted cost of avoided Phase II emissions reductions.
- EPA's 1992 Regulatory Impact Analysis (RIA) predicted cost savings of 40%, or $400 million (in 1990 dollars), from a "national SO_2 trading program" as compared with a "traditional SO_2 control program."
- The 1994 GAO report provided an estimate for intra-utility trading only, because very little interutility trading was expected: $230 million (in 1992 dollars), or 18% of the predicted cost of compliance under a "traditional command-and-control" approach.

Both the ICF and EPRI/GAO[57] studies projected some emissions trading, but the earlier ICF studies appear to have been more optimistic about the amount of trading. When normalized for the amount of abatement projected, the ICF studies predicted average costs of compliance at around $200 per ton, whereas the EPRI/GAO studies predicted costs of $300 per ton. If this difference is due mostly to the apparent differences in assumption about emissions trading, cost savings from trading of about 33% are indicated.

An estimate of the cost savings from emissions trading requires not only a measure of the amount of emissions trading, but also an estimate of the cost of an assumed and unobserved alternative in which there was no trading. The amount of emissions trading in 1995 is no longer a matter of conjecture so that,

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Coal Company, Eastern Associated Coal Corp., Kerr-McGee Coal Corp., Marine Coal Sales Co., and no doubt others for which the name of the account holder does not reveal coal industry affiliation. As of the end of the reconciliation of accounts for 1995, 71,577 allowances had been deposited into these accounts and 54,883 had been withdrawn. These amounts are not large, given the volume of coal sales, mostly because utility-fuel buyers can perform the same bundling function as coal companies by using their own allowances.

[56] ICF90 does not provide a comparable estimate of cost savings from emissions trading because it assumed flexible implementation ("trading to the fullest extent permitted") for both the higher- and lower-growth scenarios modelled (ICF90, p. 1).

[57] The two EPRI studies and GAO study are grouped together here because their estimates of average cost are so similar and these studies were also conducted by the same contractor.

at least in principle, this component of the difference that constitutes cost savings is fixed; the other component—the alternative command-and-control program from which savings are measured—is not, however. If the comparison were made with a theoretically ideal command-and-control system, cost savings would be small and perhaps nonexistent. On the other hand, a comparison with the worst imaginable command-and-control system could produce unbounded cost savings. There is plenty of room for disagreement about the command-and-control alternative and the resulting magnitude of cost savings, so any choice is at best illustrative.

The alternative we specify assumes that annual SO_2 emissions limits are established for each generating unit equal to the number of allowances allocated to individual units under Title IV. However, we permit no trading between units—either intra- or interutility. Under this "no-trading" alternative, each unit effectively cannot produce more emissions than its initial allocation of allowances. Moreover, any generating unit that produces a lower level of emissions cannot sell its unused allowances, and thus cannot benefit from operating below its emissions cap. This alternative is inherently a lower-cost benchmark against which to compare Title IV's trading program than other potential "command-and-control" alternatives would be. For example, if we were to assume that the alternative regulations require all generating units to achieve equal maximum emissions rates or equal percentage reductions of emissions, or that the law mandates scrubbing for a large fraction of units, the baseline costs of the alternative command-and-control program would be much higher.

Our "no-trading" alternative can be viewed as appropriate for several reasons. First, the objective is to estimate savings from emissions trading, broadly defined—among units owned by the same operator as well as among operators. Although most observers assumed that *intra*-utility trading would occur, neither the novelty nor the cost savings of unrestricted intra-utility emissions trading should be minimized. Second, a "no trading" formulation of the alternative to Title IV's innovative emissions trading provisions is consistent with the well-established precedent of source-specific emission limitations under the existing Clean Air Act (CAA). While CAA legislation and regulation prior to 1990 permitted "bubbles" and "offsets" of varying scope, such emissions trading was not a matter of right, as in Title IV, but could be obtained only by detailed application, with explicit, case-specific approval of the regulatory authority.[58] Lastly, this formulation of the alternative to emissions trading seems less arbitrary than either taking some degree of intra-utility emissions trading for granted, as did some earlier studies, or adopting other plausible command-and-control alternatives, such as incorporated in earlier legislative proposals.

Specification of an appropriate measure of cost savings is a necessary first step, but obtaining a reliable estimate from actual data *ex post* poses further difficulties. In contrast to the consistent behavior assumed in model simulations upon which earlier estimates of potential cost savings were based, actual data include all the consequences of the uncertainties and mistakes characterizing real markets. Simplifying assumptions can impart sufficient order to observed data to obtain an estimate, but those assumptions can be debated; indeed, data are often subject to differing interpretations.

A first issue of interpretation concerns the treatment of "excess" allowances. Of the 263 Table A units, only 155 were constrained in 1995 by the unit-level allowance allocation; the other 108 faced no requirement to reduce emissions since they received more allowances than needed to cover counterfactual

[58] See Hahn (1989), Hahn and Hester (1989), and Montero (1997b) for information on the limited response to such trading opportunities.

emissions. With no emissions trading, the 155 constrained units would have been required to reduce emissions by 2.02 million tons, in the aggregate, while the 108 units that were not constrained would have received a total of 0.96 million "excess" but worthless allowances. With emissions trading, these "excess" allowances could be used to avoid the costs associated with emissions reductions, currently or prospectively.

It is important to recognize that these "excess" allowances are not so much the result of an inappropriate or arbitrary allocation of emission permits as they are a consequence of changes that inevitably accompany the passage of time. Table A units were selected based on 1985 emission rates, and allowances were allocated based on average heat input during the three years 1985–87; yet, the allowances would not be used until 1995. In the intervening ten years, heat input varied because of load growth and changes in relative operating costs at particular units, and emission rates varied because of changes in the economics of fuel supply. **Table 12** shows how many units would have been constrained by the allowance issuance based both on 1985 emission rates and baseline (average 1985–87) heat input, and on counterfactual 1995 emission rates and heat input.

TABLE 12. CONSTRAINED TABLE A UNITS, 1985 AND 1995

	Constrained in 1985	Unconstrained in 1985	Total
Constrained in 1995	**134**	**21**	**155**
More so than in 1985	62	21	83
Less so than in 1985	72	NA	72
Unconstrained in 1995	**80**	**28**	**108**
Total	**214**	**49**	**263**

Source: Derived from EPA Emissions Monitoring System.

Note: "Constrained" means that the number of allowances issued to the unit in a given year (for 1985, baseline—average 1985–87—heat input times the 1985 emissions rate; for 1995, 1995 heat input times the counterfactual—1993—emission rate) is less than the number of tons of emissions that year). "More than" and "less than" here relate to the absolute difference between allowances and emissions. For example, a unit that is *less* constrained in 1995 than in 1985 is one for which the emission rate, heat input, or both, have changed such that counterfactual 1995 emissions are less than baseline 1985 emissions.

For instance, 152 (= 72 + 80) of the 214 units that appeared constrained in 1985 experienced changes in emission rates and heat input over the next decade that rendered the allowance constraint *less* binding; for 80 of these units, the changes were sufficient to make the allowance constraint nonbinding. Over the same time period, 62 of the 214 units became *more* constrained, primarily because of increasing heat input, as did 21 of the 49 Table A units that appeared not to be constrained in 1985. In the end, for about 60% of Table A units, intervening changes rendered the Title IV constraint less binding and less costly, while about a third of the units experienced the opposite effect.

The 960,000 “excess” allowances in 1995 are one source of cost savings from emissions trading. The cost of these allowances was zero, and they could have been used to avoid the cost of emission reductions in like amount at units that were constrained in 1995. Although some of these allowances may have been so used, in the aggregate they were not. Rather, they were banked, as were 2.4 million other allowances, presumably because avoiding the more stringent Phase II reductions offered greater cost savings. Since any one of these “excess” allowances could have been sold in the allowance market in 1995 for somewhat more than $100 each, cost savings of at least $100 million are indicated.

Banking leads to another complication: the future cost that will be avoided by banking has yet to be realized. The banking and the motivating expectation of cost savings are real, but the latter is subject to some variation. Every electric utility compliance manager has a good current estimate of the cost of further emission reductions in Phase II for his system; but, with a well-functioning allowance market, the amount of further reduction on any given system will depend on the future market value of allowances. And however well the cost of further reduction on the manager’s system is known, all would likely admit to considerable uncertainty concerning future allowance prices, which depend on compliance costs at other utilities and, more generally, on the magnitude of the aggregate emissions reduction required to comply with Phase II. The supply of allowances is fixed, but factors affecting the demand for allowances are not: for instance, load growth for all systems, the further penetration of PRB coals, the effects of electric utility restructuring, and the effect of other environmental regulation (such as the fine particulate matter standard) on the demand for electricity and on the choice of generating fuel. Thus, although no compliance manager expects to lose money by banking, the possibility exists that the future costs avoided as allowance banks are drawn down will be less on a discounted basis than the actual or opportunity costs currently incurred.

The overinvestment in compliance due to pre-1995 expectations of compliance costs and allowance prices also complicates an estimate of cost savings from banking. Overinvestment in compliance leads to both greater costs in the current period and lower allowance prices than would be the case in long-run equilibrium. The lower Phase I-allowance price economically justifies more banking, but the sunk capital costs do not figure in that current price, while future costs of deferred Phase II reductions include the capital component of least-cost Phase II abatement options. As a result, cost savings from banking depend on which present costs are subtracted from the avoided future costs. If the cost of sunk capital is treated as a bygone, as it is in the oversupplied current market, cost savings from the banking occasioned by overinvestment in compliance are likely to be large. However, if the cost of sunk capital is included, no cost savings whatsoever may be realized.

Uncertainty about the higher costs avoided by emissions trading impacts decisions affecting current-year operations, as well as decisions to bank allowances for future use. In 1995, 71 of the 155 constrained Table A units did not reduce emissions by the amount implied by their allowance issuance; instead, they obtained a total of 456,000 additional allowances from other, overcomplying sources. Even though these cost savings were actual—in contrast to what can be only prospective savings with banked allowances—the cost savings estimate is uncertain because costs avoided by acquisition of these additional allowances cannot be observed.

The treatment of substitution and compensation units presents a further confounding factor in any estimate of cost savings from emissions trading in 1995. This provision of Title IV sought to provide further opportunities for cost savings by allowing Phase II units to make voluntary emissions reductions in Phase I. Though this option generated a large response, its contribution to the aggregate emissions reduction in

1995 was relatively small: about 213,000 tons, or about 5%, of the total 3.9-million-ton reduction. Moreover, some 242,000 "excess" allowances were distributed to these units in the aggregate that, like the analogous allowances for Table A units, can be used to avoid costs associated with current or prospective emissions reductions.[59] Although actual or prospective cost savings can be presumed for the additional 213,000-ton emissions reduction attributable to substitution and compensation units, interpretation of the abatement costs avoided by the 242,000 "excess" allowances is more problematical, in that an argument can be made that the cap has been violated.[60]

A final challenge in estimating cost savings involves the identification and inclusion of cost-reducing innovations that may have been induced by the flexibility associated with emissions trading. The penetration of PRB coals would not have been as great, had ways not been found to adapt Midwestern boilers built for local bituminous coals to blends with these sub-bituminous coals. While such adaptation was observed prior to 1990 in response to the increasingly attractive delivered price of PRB coals, the diffusion of this innovation may well have been accelerated by Title IV. Similarly, the lower operating cost and greater utilization of Title IV scrubbers reduced compliance costs in 1995, but it is unclear whether the cause of this reduction had to do with exogenous change in information technology, a more competitive regulatory environment, or the incentives for lower cost and greater utilization provided by emissions trading. No doubt, other examples of innovation that reduced compliance costs exist, but the problem of attribution to emissions trading remains.

Such a summary of qualifications and ambiguities should offer the reader a fuller appreciation of the difficulties of reliably estimating cost savings from Title IV's emissions trading provisions—or of even posing the question well. A tentative estimate by one of the present authors indicates savings of $225–375 million dollars (1995), or what amounts to 25–34% of the cost of abatement for the same emissions reduction in the absence of trading.[61] This estimate indicates cost savings within the range that can be derived from the earlier studies of compliance cost with Title IV, though it is low, given that the volume of emissions trading in 1995 was much higher than that predicted by all earlier studies.[62] In any case, this

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[59] In theory, there should be no issuance of "excess" allowances for substitution units, but the same problem is encountered here as with the Table A units: changes occurring between the time when the baseline is determined and actual implementation. Specification of the appropriate baseline for distributing allowances to substitution units was the major point of litigation in implementation of Title IV; the result was an updated but more complex baseline. The reality of the issuance of allowances to substitution and compensation units is more complex than suggested here. Actually, 394,000 "excess" allowances were distributed to 132 substitution and compensation units; the remaining 60 substitution units, however, were short a total of 152,000 allowances.

[60] See Montero (1997a and 1997b) for extensive discussions of the empirical and theoretical aspects of Title IV's voluntary compliance program.

[61] See Ellerman (1997).

[62] All earlier studies predicted much less banking than actually occurred. For instance, ICF90 projected 243,000 allowances banked in 1995, and while the later EPRI and GAO reports were closer to the mark, with 1.76 million and 2.1 million allowances, respectively, they were still well below the 3.4 million allowances actually banked. A considerable amount of the observed banking must be attributed to the unexpected extent of overinvestment in compliance. In contrast, the amount of spatial trading in 1995 was less than the more optimistic earlier predictions. For instance, ICF90 anticipated trades totalling 663,000 allowances among states—more than the 540,000 allowances traded spatially in 1995, including intra-utility trades within the same state. In comparison,

estimate is less than the magnitudes often attributed to the use of market-based instruments in the academic literature. In a frequently used textbook, Tietenberg (1992)[63] cites earlier studies covering a variety of pollutants, for which the ratio of cost for a traditional command-and-control program compared to a least-cost market-based approach is usually greater than 4 and may be as high as 22 (equivalently, savings range from 75% to 95%), although the two studies cited for SO_2 control have ratios of 1.78 and 4.25 (savings of 45% and 76%). Our lower estimates of cost savings from emissions trading under Title IV may reflect little more than the many different ways to define and measure cost savings, but it is also likely that neither the earlier predictions nor actual implementation in 1995 have realized the full potential of cost savings from emissions trading. In any case, savings of even 25% in 1995 are not to be dismissed simply because they are not larger.

It is likely that cost savings from emissions trading are lower than might be supposed because we are evaluating the real—not the ideal—implementation of Title IV. It is all too easy to confound cost savings from emissions trading with the costs savings that might have been realized had compliance been achieved in the most efficient manner possible, in a world with perfect foresight. Hindsight facilitates the identification of investments in retrofitted scrubbers and contractual commitments for low-sulfur coal supplies that would not have been made had it been known at the time of commitment that allowances would be worth significantly less than the $250–350 commonly predicted for Phase I. The cost of compliance with Title IV would have been lower had the parties not made these irreversible commitments—although, had most parties forestalled their commitments, allowance prices and coal sulfur premia in 1995 would likely have been higher. Finally, the most efficient compliance scenario was precluded by Title IV's own Phase I extension provisions, which provided extra allowances for scrubbers that would operate during Phase I. Although separating overinvestment due to bonus allowances from overinvestment due to mistaken expectations of allowance value would be difficult, the extension provisions almost surely led to more scrubbers than otherwise would have been built during Phase I. In any case, the estimate of 1995 cost savings from emissions trading that is offered here is conditional on Title IV, with respect to both its design and its implementation.

EPRI93's prediction of 103,000 allowances traded spatially among utilities in 1995 was not far from the actual number of 148,000.

[63] *Cf.* p. 403.

VIII. CONCLUDING OBSERVATIONS

The U.S. Acid Rain Program—Title IV of the 1990 Clean Air Act Amendments—is significant both as environmental policy for reducing SO_2 emissions that contribute to acid rain and as a more general experiment in environmental policy. While it is still too early to evaluate fully the performance of Title IV, experience to date suggests a number of conclusions. As environmental policy, and when judged from the perspective of reducing SO_2 emissions at reasonable cost,[64] Title IV has clearly been a success. Not only did the program more than achieve the SO_2 emissions goal established for Phase I, but it did so on time, without extensive litigation, and at costs lower than predicted. Few environmental programs have succeeded in all these dimensions.

When Title IV is viewed as a more general experiment in environmental policy, however, conclusions must be drawn cautiously. The difficulty of specifying an alternative scenario to which Title IV should be compared is an important complication. A good deal has been written comparing real command-and-control policies with ideal market-based policies. This report has considered a real—and thus imperfect—market-based policy. Comparing it with an unfeasible ideal—whether market-based or command-and-control—makes little sense. Furthermore, there is inevitably arbitrariness in comparisons with hypothetical policies that are also imperfect. Despite these conceptual problems, we believe several important general lessons follow from experience so far with Title IV:

1. *Foremost, we have learned that large-scale tradable permit programs can work more or less as textbooks describe*. By providing flexibility to emitters, such programs can achieve both the environmental objective and a reduction in compliance costs. Though it is difficult in both principle and practice to quantify the cost savings achieved thus far by Title IV, we believe our analysis establishes that those savings have been substantial. Given the controversy this approach to environmental policy sparked when first proposed, it is heartening that this lesson appears to have been widely learned.

   Indeed, some observers seem to have learned this lesson too well, coming to regard the tradable permit approach as a viable solution for almost any environmental problem. Available evidence from Title IV does not support this view. While allowance *prices* have been less than half of earlier forecasts, the difference between expected and actual compliance *cost* has been much less dramatic. In addition, some of the difference in cost has been unrelated to Title IV—for instance, the significant and apparently unforeseen lower delivered price of low-sulfur coal from the Powder River Basin. A fair conclusion to be drawn from experience to date with Title IV is that tradable allowances offer a valuable policy tool—not a panacea or even necessarily the best approach to all environmental challenges.

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[64] Inquiry into the benefits of reduced emissions is beyond the scope of this study. NAPAP (1997) provides a discussion of the effects and benefits of the reduction of SO_2 emissions effected so far by Title IV. In general, the pertinent sections state that a statistically significant reduction in sulfur deposition has been observed in 1995 by monitors located in the Northeast and the Ohio River Valley, but that similarly significant changes in the acidity of waters or other indicia of ecosystem response have not been observed, because of the longer response times of these complex processes.

2. *One can expect a tradable allowance program both to produce surprises and to adapt reasonably efficiently to them.* The more flexible a regulatory program, the more unexpected behavior it will produce as regulated firms exercise ingenuity in adapting to the new requirement and to unexpected events in related markets that affect efficient control strategies and optimal emission levels. Fundamentally, the fixed emissions ceiling of a tradable allowance program minimizes the potential environmental harm such cleverness can produce. The big surprise here was the rapid expansion of the market area for Powder River Basin coal, due mostly to the reduction of rail rates caused by the deregulation of railroads in the 1980s. As a result, the emissions reduction required in the Midwest was less than expected, but the allowances thereby made available were not used to lessen emission reductions at units located closer to the sensitive environmental areas in the Northeast. Instead, these extra allowances were saved for later use to ease the transition to more stringent Phase II emission reduction requirements.

   The Title IV program did not adapt perfectly to this surprise. More investment in scrubbing occurred than would have been optimal had the required emission reductions and allowance prices been predicted more accurately *ex ante*. But the market did react to the information contained in the allowance prices revealed by the first EPA auction, and orders for some scrubbers were canceled. The banking provisions then ensured emission reductions beyond what was required to meet the cap, without new legislation or regulation, because these reductions were cheap *ex post*. It is hard to imagine any command-and-control regime adapting as sensibly to such an important exogenous event, particularly since such programs generally lack any incentives for the production or dissemination of information. The response here was not only cost-effective, but also environmentally beneficial, particularly for a pollutant whose effects are thought to be cumulative. From this experience, banking appears to be a potentially important source of cost savings in tradable-permit programs.

3. *"Opt-in" provisions need to be carefully considered, as they may not always be advantageous.* Many of the complexities and administrative difficulties encountered thus far in the Acid Rain Program reflect the fact that Phase I covers some—but not all—sources of SO_2 emissions. The program included substitution and compensation provisions for electric utility generating units and opt-in provisions for industrial sources to permit the substitution of lower-cost emissions reductions where possible. The response by electric utility units was substantial; however, the overall contribution of these units to the 1995 emissions reduction was small, as was the cost savings from emissions trading with these units. The widespread participation by electric utility sources appears to have been induced by over-generous allowance allocations that will result, in all likelihood, in some increase in emissions. The slight increase of emissions over the course of the program will occur because any "opt-in" provision that is attractive to some emitters for cost-saving reasons is almost certain to involve provision of unneeded allowances to at least a few who are likely also to opt in. In retrospect, it appears that the most cost-effective Title IV emission reductions were to be found at the more highly emitting units—which were, by design, those required to participate in Phase I.

4. *Efficient, competitive markets for tradable permits can develop when program design and implementation are favorable.* Title IV was signed into law in November 1990, and its final rules adopted in January 1993. Our analysis indicates that by around the middle of 1994, an efficient market for allowances had emerged. Important contributing factors to the development of this market were the fundamental design of an "allowance" and the subsequent implementation of the Acid Rain Program by the EPA. The key design elements were, first, that *de facto* rights to emit SO_2 were being

traded rather than reductions of SO_2 emissions, and second, that each allowance was worth the same amount (one ton of SO_2) regardless of when or between whom it was traded. The distinction between trading rights and trading reductions may seem sophistical, since the number of permits implied a significant emissions reduction; however, it is important for the development of a market.

Emissions are what damage the environment, and measuring them is, at least in this case, a relatively routine engineering problem. Specifying and fixing emissions reductions, on the other hand, cannot be done so easily unless it is known in advance what emissions would have been. Such counterfactual emissions levels are never easily ascertained; and the need for administrative review and approval of counterfactual emissions baselines increases transactions costs enormously. In implementation, the EPA deserves significant credit for resisting opportunities to review and approve compliance and trading decisions by private parties and for focusing instead on the integrity of emissions monitoring and on a strict, no-excuse, banker-type accountability for emissions and allowances. The commendable focus on result, without regard to intent or effort, minimized transaction costs and further encouraged the development of the allowance market. Finally, regardless of the theoretical strengths and weaknesses in the design of the EPA-administered allowance auction, the simple fact that a transparent mechanism existed in the early stages of implementation to facilitate the revelation of an allowance price encouraged the development of a market.

One misconception about the allowance market that has appeared several times in the press deserves correction. Trading volume *per se* is no measure of a tradable allowance program's success. A relatively low volume could mean either that transaction costs are so high that many socially beneficial trades are not economic, or that the volume of socially beneficial trades is relatively low. For example, if allowances are allocated to match exactly the cost-minimizing emissions pattern, no trades will occur in an efficient equilibrium because compliance costs cannot be reduced by trading. In the Acid Rain Program, we have seen a remarkable increase in the volume of trading since the program's inception, which suggests both that transaction costs are low and that participants are taking advantage of many opportunities for socially beneficial trades.

5. Experience to date with Title IV makes it clear that *tradable permit programs can neither achieve textbook perfection nor guarantee breakthrough innovations in practice*. The glass is both half empty and half full. We have noted, with 20/20 hindsight, that over-investment in scrubbing almost certainly occurred because allowance markets took time to develop, and because investment decisions about scrubbers and boiler modifications had to be based on price expectations for low-sulfur coal that proved to be high. In an ideal, textbook world, price discovery would have been instantaneous, resulting in no overinvestment. While one can imagine program design changes that would move toward this ideal, there is no way to reach it in the real world, in which information becomes available over time, and its discovery and dissemination are costly. On the other hand, since command-and-control programs do not generally embody incentives for information discovery and dissemination, a command-and-control program would likely have translated the initial expectation error into even greater excess cost. Finally, while we have seen instances of innovation that may be attributable at least in part to Title IV—most notably, the sharp fall in the cost of scrubbing compared to expectations, and extensive use of fuel blends involving sub-bituminous PRB coal—we have seen nothing that would qualify as a "breakthrough" in SO_2 abatement technology.

All this suggests one final observation: *experience with and lessons learned from the Acid Rain Program must be applied with care to other environmental objectives.* The Title IV experience provides some support for those who argue that a well-designed tradable allowance program for greenhouse gases is likely to out-perform alternative responses to global climate change. However, the Title IV experience also illustrates the complexity of the problem of designing an emissions trading program in the climate change context.[65] The Title IV program was built on accurate emissions monitoring and strong penalties for violations—elements almost certain to be absent from international agreements on climate. In addition, much of the complexity in Phase I of the Acid Rain Program stems from its partial coverage of relevant sources, a design element almost certain to be present in any international climate agreement. Finally, the Acid Rain Program was designed to specify emission limits once and for all; any sensible climate change regime must permit emission limits to be changed several times, at least, over the course of a century or so. These and other differences can have major impacts on both optimal design and program performance.

[65] See Schmalensee (1996).

APPENDIX: METHODOLOGY OF COST ESTIMATION

The cost of compliance is an incremental concept; it is the additional cost incurred to comply with some environmental or other legal requirement. In the case of Title IV, the cost of compliance is the additional cost of generating electricity at affected units, and consists of components for both capital and operating cost. The capital cost takes the form of an appropriate annual amortization of the initial investment in scrubbers and in equipment required to switch to coals other that those for which a boiler was originally designed. The incremental operating costs are typically the premia attaching to lower-sulfur fuels and the operating costs of running scrubbers. This appendix explains the sources of data and the several conventions we have adopted to arrive at the estimate for the cost of compliance with Title IV that is presented in the body of this report.

The largest single category of expenditure for complying with Title IV is the $3.5 billion investment in retrofitted scrubbers at 26 Table A units at 15 electricity-generating plants. Because of the cost and the implications for coal choice, electric utility decisions to retrofit scrubbers have been extensively reported in the trade press, and the estimated cost of retrofits has been covered in some detail by earlier studies of Phase I compliance strategies, particularly in the excellent reports sponsored by the Electric Power Research Institute.[66] The figures reported for investment in retrofitted scrubbers in EPRI95 are nearly identical to those given in response to the MIT/CEEPR questionnaire. Accordingly, for those utilities that did not respond to the questionnaire, we have used the estimates of capital expenditure contained in EPRI95.

The capital investment for switching is not nearly as significant as that for scrubbing, and there is much less information available on this component of compliance cost. As a result, we have placed greater reliance on responses to the MIT/CEEPR questionnaire and also on inference based on changes observed in emissions and the sulfur content of fuel deliveries in 1995. The questionnaire responses indicate that the capital cost associated with switching to a sub-bituminous PRB coal ranges from $15 to $75/Kw^e, depending on the plant, and that the cost of a switch to other bituminous coals ranges from zero to $15/KW^e. Where a questionnaire response (and in some cases, other sources) provided the initial capital investment for switching, that data has been used; otherwise, a default value of $50/KW^e has been adopted where a switch to PRB coal is observed, and a default value of $10/KW^e has been applied to those units where switching to lower-sulfur bituminous coals resulted in an emissions reduction of more than 0.5 #/mmBtu. Both default values are based on responses to the MIT/CEEPR questionnaire.

The initial capital investments in scrubbing and switching are amortized using a simple formula that recognizes interest cost, an allowance for depreciation, and inflation:

$$F_t = \left(\frac{K_0}{T} + rK_t\right)(1+i)^t$$

[66] EPRI93 and EPRI95.

where F_t is annual fixed cost for year t, K_0 is the initial investment cost, T is the life of the capital equipment, r is a *real* interest rate, K_t is the undepreciated investment at the beginning of each year, and i is the inflation rate. All capital is assumed to have a life of 20 years, the real interest rate is estimated at 6.0%, and the inflation rate at 3.0%. Based on this formula, we applied an annual capital charge of 11.33% to the reported or inferred capital investment at the 70 plants that reduced SO_2 emissions noticeably in 1995.[67]

Turning now to the incremental operating costs associated with Title IV compliance, those for scrubbing consist of a charge and, in some cases, a credit. The charge is the nonfuel operating expense: limestone or other absorbent material, sludge disposal, and the "parasitic" loss of power to run the scrubber. Based on questionnaire responses and further inquiry, we estimate this cost to be $65 for every ton of SO_2 removed by scrubbing.[68] A credit is recognized where units retrofitted with scrubbers switched in 1995 to a higher-sulfur coal than was used in prior years. Additional sulfur requires more removal by a scrubber, but so long as the value of an allowance exceeds the operating cost of the scrubber, the switch to a cheaper, higher-sulfur coal reduces the cost of generation from what it otherwise would be. This credit reflects the savings in fuel cost that is the mirror image of the additional cost for units switching to lower-sulfur coals. As is the case with the charge for switching to a lower-sulfur coal, this credit is computed using the spot-market sulfur premium observed in the region supplying the coal.

For switching, the principal operating cost is the premium for lower-sulfur fuel that would not have been chosen except for Title IV. In contrast to units with retrofitted scrubbers, switched units have little, if any, additional non-fuel operating costs, so none are included in these estimates.

Unfortunately, and despite the ready availability of monthly data on the cost of coal delivered to power plants, the premia paid for lower-sulfur fuel are not easily observable. Not only do delivered prices include transportation costs unrelated to sulfur premia, but changes in contract terms and conditions further confound delivered prices' interpretation. Even when contract and transportation factors can be held constant, inter-year comparisons can mislead. The sulfur premium is at best 20% of the price of a coal (usually less), and the more significant value of heat content not only varies from year to year, but has also declined steadily. In particular, coal prices generally declined in 1995, and lower-sulfur coal was frequently delivered at lower prices that year than higher-sulfur fuel delivered to the same plant in 1993 or 1994.

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[67] The nominal interest rate is often applied in such calculations; however, use of the nominal interest rate when inflation is positive leads to different rental rates for different vintages of capital that provide identical services. This problem is avoided by recognizing that real capital services are properly discounted by the real interest rate, and the payment or rental rate for those services is then inflated. Our 6% real interest rate was obtained by subtracting an estimate of 3.0% for inflation from a nominal weighted average cost of capital for electric utilities in 1995 of 9.0% that was kindly provided by Paul Maleh of Charles River Associates, Inc., to whom we are appropriately indebted.

[68] The variable cost of scrubbing is usually given as so many mills per kwh, depending on the sulfur content of the coal being scrubbed: the relationship between the mills/kwh charge and sulfur content is highly linear and positive, so that when converted to dollars per ton of SO_2 removed, the cost is approximately constant at $65 per ton of SO_2 removed.

Fortunately, in most cases it is not necessary to look at delivered prices. Most bituminous coal-switching in 1995 involved coals from the same coal-supply region. Therefore, if mine-mouth prices can be observed in the coal-supply regions, the confounding influence of transportation charges and contract factors can be avoided. The trade press regularly reports mine-mouth prices for the principal types of coal produced in all coal-supplying regions. If the reasonable assumption is made that buyers and sellers of coal are well informed of all the components of value, including sulfur content, then attempts to decipher sulfur premia from delivered prices are unnecessary. Those premia can be calculated for 1995 and earlier years from the differences observed between representative spot-market prices reported for coals of differing sulfur content in each coal-producing region.

For our calculations of the premia for lower-sulfur coal, we relied on spot-market prices reported by *Coal Outlook* since late 1991. Where switching among bituminous coals from the same supplying region was observed, we assigned the sulfur premium prevailing in the region. Most 1995 contract deliveries would have been negotiated prior to 1995, so we assigned the average spot-market sulfur premium for the originating region in 1993 or 1994, on the assumption that no additional *contract* premium was paid for lower-sulfur content. For 1995 spot deliveries, we assigned the spot-market premium prevailing for the region in 1995. When the switch to lower-sulfur coal also involved a change of supply region, we had no recourse but to look at delivered prices; in those cases, we assigned a premium based on differences observed in the 1995 prices for coals of differing sulfur content delivered to the plant in question and to nearby plants.

Two special cases of switching deserve further comment. First, for any plant switching to PRB coals, the delivered cost of the PRB coal will always be less than the delivered cost of the higher-sulfur coal it is replacing: the significant investments for upgraded precipitators and coal- and ash-handling equipment that must be made to accommodate sub-bituminous coal in a generating unit designed to burn bituminous coals are not made unless the capital outlay can be justified by compensating savings in fuel cost, including (beginning in 1995) the value of allowances.[69] We handled the 12 plants containing 31 units switching to or increasing the blend of PRB coal in 1995 on a case-by-case basis. If a unit's observed savings in fuel cost exceeded its annualized capital cost, we recorded no compliance cost; otherwise, the positive difference represented compliance cost. For most units switching to PRB coals in 1995, as for those that switched earlier, no net cost of compliance is apparent.[70] Nevertheless, several plants on the eastern frontier for PRB coals did record positive costs for switching to PRB coals in 1995, which are included in our estimates. Although the predominant source of no-cost compliance was PRB coal, in several instances western bituminous coals also became economic in the Midwest due to falling rail rates, and in other instances, units lowered their total generating cost by switching to natural gas from oil.

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[69] The same argument applies for switching to a lower-sulfur bituminous coal; however, the additional capital investment is sufficiently small that the compensating difference in delivered fuel cost lies within the usual variation of delivered fuel prices.

[70] The timing of these switches was likely determined by contract expiration or a reformation of the contract to accommodate Title IV. In the latter case, termination payments may have been made, but do not constitute part of the cost of compliance with Title IV. Contract law would require damages approximately equal to the present value of the difference between contract and market price, should the contract be breached. Since contract law is enforced in American courts, we assume that suppliers extract such payments or equivalent value from the buyer when contracts are reformed voluntarily.

The second special case involves long-term supply contracts. A number of Phase I-affected units have been supplied with coal under 20-, 30-, and even 40-year contracts, signed mostly before the 1980s, that linked mine to power plant for the term of the contract.[71] Like all contracts, these are enforceable in the courts, and Title IV explicitly did not provide grounds to renege on agreements.[72] The pricing provisions of these contracts reflect energy price expectations at the time of signature, so current contract prices are often higher than the current market prices for new contracts or for spot coal of the same quality. The increasing disparity in contract and market prices over the past ten years has led not only to considerable dispute—judicial and otherwise—but also to an accommodation with respect to Title IV that provides lower-sulfur coal at no extra cost. Several electric utilities encumbered by such contracts and by Phase I-affected units appear to have prevailed upon their suppliers to provide lower-sulfur coal at the same contract price. The utility pays no fuel premium in these cases, but there is a resource cost to society: the additional cost of supplying the substitute coal. In effect, the supplier foregoes some profit to deliver a higher-cost, lower-sulfur coal in exchange for a reduced chance of litigation or other form of buyer harassment (for instance, rejection of slightly out-of-spec coal) and, more importantly, for an improved prospect of continuing to supply the buyer when the current contract expires. From a societal standpoint, the extra costs incurred by the supplier are resources devoted to compliance, just as surely as had the utility paid the producer more explicitly. In fact, the supplier would have received that premium for the coal, had the supplier not decided to supply the coal under the favorable pre-existing contract. To reflect this cost, the sulfur premium obtaining in the supplying region is assigned in those instances where a lower-sulfur coal is delivered under an existing contract at little or no additional cost.

[71] See Joskow (1987) for a discussion of these contracts.

[72] A number of contracts signed from the mid-1980s on specifically included provisions that allowed termination or appropriate modification if and when proposed acid rain legislation became effective.

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