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The Costs of Reducing Utility SO_2 Emissions -- Not as Low as You Might Think

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SUMMARY

A common assertion in public policy discussions is that the cost of achieving the SO_2 emissions reductions under the acid rain provisions of the Clean Air Act ("Title IV") has been only one-tenth or less of what Title IV was originally expected to cost. Initial cost estimates are cited in the range of $1000 to $2000 per ton of SO_2 reduction and contrasted to SO_2 allowance prices of about $100 per ton. Unfortunately, these are "apples-to-oranges" comparisons, leading to erroneous conclusions that greatly overstate the true divergence of actual costs from initial cost estimates. When the facts are viewed in a conceptually appropriate, "apples-to-apples" context, one finds that actual costs for SO_2 reductions have been and are likely to remain near the low end of the initial range of estimates.

We all must learn to recognize conceptual pitfalls in these assessments of the SO_2 program, to avoid unrealistic expectations of major new regulatory initiatives. For example, many regulatory advocates are now using the erroneous characterization of Title IV costs being one-tenth or less of their originally projected levels to argue that the new market-based regulatory approaches render *ex ante* cost estimates meaningless or at least much too high. This fundamentally incorrect line of reasoning already has been used to dismiss concern over cost estimates for new regulations, such as the $PM_{2.5}$ and ozone air quality standards. These and other major policy initiatives deserve to be debated in light of appropriate and realistic assessments of their likely costs. This requires correcting the current misunderstandings about the actual costs of the Title IV SO_2 emissions allowance market.

The following paper leads the reader through an interpretation of the facts regarding the estimated and actual costs of the SO_2 program. Some of the key points include:

(1) Initial cost estimates for the Title IV SO_2 program were *not* over $1000 per ton.

(2) Initial cost estimates for a fully-implemented Phase II cap ranged from $225-500 per ton, and costs were projected to be lower than this until the Phase II cap would be fully achieved, about ten years from now.

(3) Much confusion has arisen from comparing different cost and price concepts that become important in an allowance trading system, such as average and marginal cost, and the price of an allowance.

(4) When a market has a temporary oversupply (which has been true of the SO_2 allowance market), spot market allowance prices will fail to reflect the capital cost portion of control costs, which can be a large part of the total costs.

(5) The allowance price may reflect future control costs, but regulatory uncertainty may cause future costs to be highly discounted.

The *average* control cost actually experienced in Phase I has been about $200 per ton. This is within the range that was initially projected. Today's most up-to-date estimates for Phase II (future) average costs are about $185 to $220 per ton. This is at the low end of the initial range

of estimates. Allowance prices have been much lower, but we explain how they are consistent with actual average costs of $200 per ton.[1]

INTRODUCTION

The environmental policy community frequently hears statements that the SO_2 reductions of Title IV have actually cost one-tenth or less of the original estimates. These statements are being used in the highest policy circles:

- In justifying EPA's proposed new National Ambient Air Quality Standards (NAAQS) for particulate matter (PM) and ozone in the face of evidence that their costs may dramatically exceed benefits, EPA Administrator Carol Browner stated in Congressional testimony that:

> *…during the 1990 debates on the Clean Air Act's acid rain program, industry initially projected the costs of an emission allowance…to be approximately $1,500…Today those allowances are selling for less than $100.*[2]

- During the White House briefing announcing President Clinton's global climate change plan, Chair of the Council on Environmental Quality Katie McGinty stated that this plan to achieve an almost 30% reduction in U.S. greenhouse gas emissions was one that would "seize economic opportunity":

> *We've reduced the emissions that cause acid rain by more than 40 percent of what was required under the law for less than a tenth of the price that was predicted…we will put [the same] market forces to work to help us take on this [climate change] objective*.[3]

Comments of this sort are widely used in many other forums, sometimes with even greater imputed cost reductions. These statements are being used to justify undertaking some of the most ambitious new air quality initiatives ever considered. It is essential, therefore, that the policy community understand why these statements are misleading, and that the record be set straight regarding an appropriate interpretation of the experience with SO_2 emissions trading and Title IV control costs.

The advent of innovative market-based tools requires non-economists and non-engineers to understand a broad array of economic terminology and cost concepts. If we are to effectively apply these innovative tools in many different settings, the policy community must learn to distinguish the concepts, and to interpret observed and potential regulatory outcomes in a valid manner. It is no longer possible to directly compare numbers just because they are all labeled in terms of "dollars per ton". It is now essential to understand whether a cost is an average or a

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[1] This paper was written prior to the sharp run-up in allowance prices to $200 in the summer of 1998. This price has appeared only towards the end of Phase I, but it is more consistent with actual, total Phase I costs. As will become apparent, our attention in this paper is focused mostly on comparisons made to early Phase I allowance prices, which were around $100.

[2] Testimony of Carol M. Browner, Administrator, U.S. Environmental Protection Agency, before the Committee on Environment and Public Works, United States Senate, February 12, 1997.

[3] Transcript of Climate Brief by Sperling, Tarullo, others, U.S. Newswire via Individual Inc., Washington DC, October 22, 1997.

marginal cost, short-run or long-run, whether it is an expenditure or a market price, *ex ante* or *ex post*. Sound confusing? It can be, and some of the current debate indicates just how far off-base policy prescriptions could stray if care is not taken to avoid comparing "apples and oranges."

This paper explains the various concepts, their relationships to each other, and then makes the appropriate comparison of the estimated and observed Title IV costs. This paper does not attempt to address the question of what a command-and-control type of program might have cost compared to the costs of the market-based Title IV program. Those benefits of trading, the more common topic in papers about Title IV, appear to have been close to what economists originally suggested. Rather, we focus on how the prospective cost estimates for the SO_2 trading program compare to the actual costs experienced, or that might yet occur in Phase II.

The authors draw on the extensive data and analyses performed independently at Massachusetts Institute of Technology (MIT) and at EPRI (formerly the Electric Power Research Institute) to provide an updated perspective on Title IV's costs, and to make appropriate comparisons with earlier cost estimates. MIT was charged by the U.S. government with assessing the experience associated with the first few years (Phase I) of Title IV, whereas EPRI is charged by its members with providing information on prospective compliance cost circumstances to help them make the best possible corporate decisions with respect to fuel and compliance. Thus, EPRI researchers are more focused on a longer-term view of the future of Title IV (into Phase II), and updating that view on the basis of current experience and information. We provide here a unified explanation and comparison of originally estimated, actual, and possible future Title IV costs.

BRIEF DESCRIPTION OF TITLE IV

Possible controls on emissions of SO_2 because of its contribution to acid rain were debated for over a decade before Title IV was enacted in 1990. Proposals differed regarding the magnitude of SO_2 emission reduction, as well as when and where the cuts would be made. Many of the proposals for legislation prior to about 1987 did not embody much flexibility regarding what control measures might be selected by individual sources. Some of the proposals implied widespread use of flue gas desulfurization (FGD), which can be very costly for some generating units. By the late 1980's, the idea of emissions trading had started to emerge from academic discussions as a political reality and legislative proposals became increasingly flexible in terms of implementing SO_2 reductions. Cost estimates for a reduction of about 10 million tons per year fell as proposed flexibility increased and as assumptions changed about other aspects of the energy economy.

When comparing projected and actual costs of Title IV, it is important to use those cost projections that assumed a form of implementation similar to that ultimately adopted in Title IV. This means that many of the cost estimates prior to about 1988 should not be emphasized in such a comparison. Further, there are a number of unique aspects of Title IV that are important in interpreting both cost estimates and actual allowance market prices. The key components of Title IV that are discussed in this paper are:

- An ultimate cap of about 9 million tons annually was set on emissions, to be achieved in two "phases". Phase I, starting in 1995, was to bring emissions down roughly one-third of the way to the ultimate cap by requiring only 263 generating units at 110 power plants to balance their emissions with allowances.[4] In Phase II, starting in 2000, effectively all major fossil units will have to obtain allowances to operate, and only about 9 million allowances will be allocated for each year.

- Allowances not used in one year may be "banked" for use in any future year. Phase I allowances may be banked for use in Phase II. Banking has encouraged "early compliance" whereby the aggregate set of Phase I units reduced emissions even more than the Phase I caps required. The bank accumulated during Phase I will start to be drawn down when the cap becomes more stringent in 2000, thus easing the transition to Phase II.

As a result of the combination of banking and a phased implementation, the legislated caps are being more than met in early years, but in turn, the ultimate cap of 9 million tons per year total will not be met until well after the official beginning of Phase II. Figure 1 shows how the bank has allowed actual emissions to take a different time path than is implied by the cap in each year.[5] In the quote above, McGinty states that Title IV has caused emissions to be reduced by "more than 40 percent of what was required under the law." This narrowly views only the first years of a multi-year phase-in plan. Due to phase-in and banking provisions, emissions are likely to substantially (and legally) exceed the annual cap starting in 2000. The beginning of Phase II marks the beginning of an era of "undercompliance," as the bank being created by today's "overcompliance" will allow the full force of the Phase II cap to be delayed.[6] It is currently estimated that the bank will supplement compliance strategies until sometime between 2005 and 2012, depending on a variety of uncertain factors.[7]

Banking of allowances and the presence of a two-phase implementation have to be taken into account when interpreting the allowance prices now being observed. Most of the historical cost estimates that have been discussed, however, apply to a fully-implemented SO_2 cap (9 million tons per year) and should not be compared to any evidence on what Title IV has "actually cost" to date, only part way through Phase I. However, we do have relevant information for updating our view of the actual costs of Title IV in the allowance market experiences of the past several years.

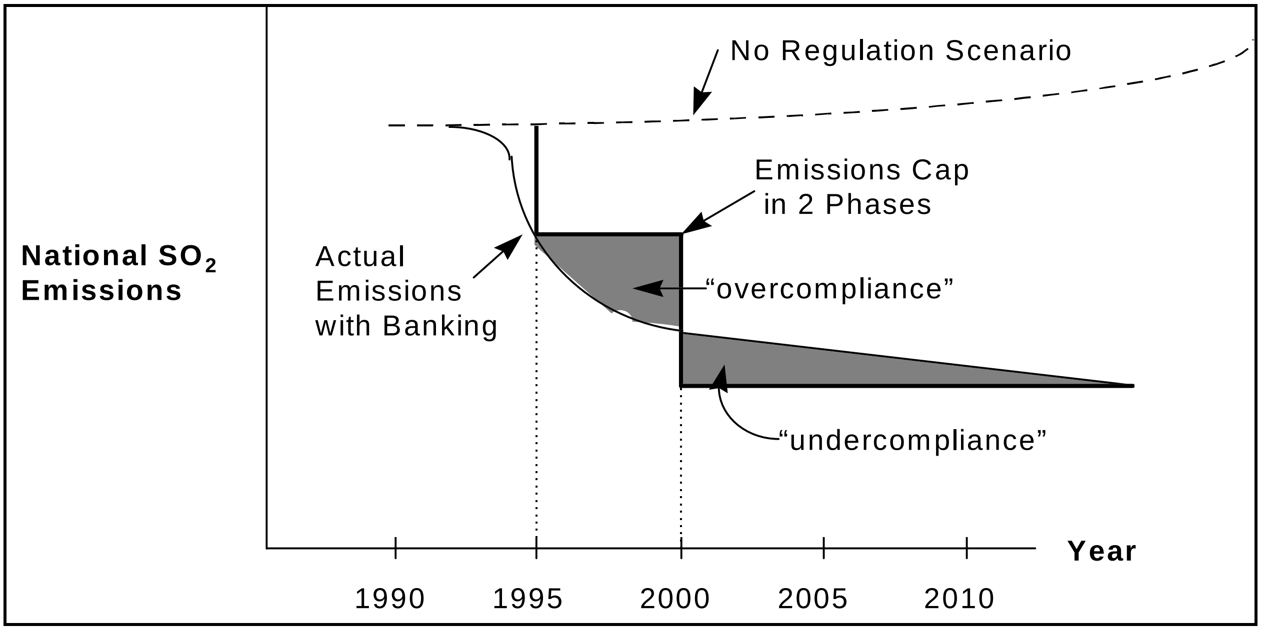
[4] 182 additional units opted-in to Phase I in 1995, so that Phase I has included as many as 445 units in one year. Slightly fewer units opted-in in 1996 and 1997.

[5] Strictly speaking, the "cap" is cumulative, as any year's cap may be augmented by consuming unused (banked) allowances from prior years. Most references to the annual SO_2 emissions cap, including those used here, mean the number of allowances issued for that year.

[6] Environmentally speaking, however, early reductions are better than later reductions.

[7] EPRI; SO2 *Compliance and Allowance Trading: Developments and Outlook*; (prepared by K. D. White); Palo Alto, California; April 1997; TR-107897; p 1-12.

Figure 1. Illustration of Effect of Banking on Achievement of Emission Caps in Two Phases.



APPROPRIATE INTERPRETATION REQUIRES CLEAR TERMINOLOGY

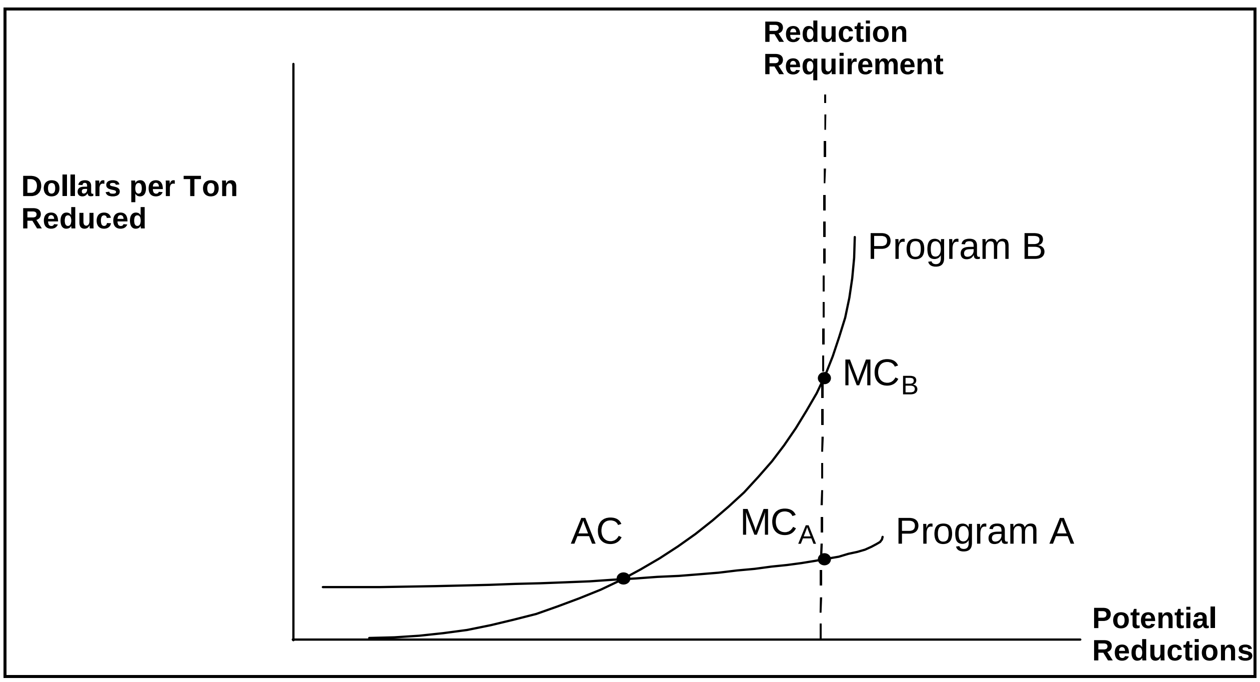
Emissions trading is a relatively new regulatory tool, and Title IV is its most important application to date. Trading has led to use of cost and price terminology that can be misleading and needs to be clarified before we move on to comparing projections and observations of costs and prices from the SO_2 trading program.

In developing cost estimates for an emissions control program, an analyst typically assesses the control actions that would be necessary for each source or category of sources and estimates the associated cost, usually based on engineering data and studies. The aggregate total cost of a program is the sum of all of the individual sources' control costs (both capital costs and operating costs). Often, the total cost is stated terms of total *annual costs* to reflect the actual expenditure flows experienced by those paying for the controls, including annual payment of capital and interest. All of the estimates discussed here focus on the direct costs of emissions-reducing actions ("total control costs"), and do not include ancillary costs such as government administration and emissions monitoring.

The total annual control cost poses some problems in comparing among alternative programs if the programs also involve different amounts of tons reduced. To allow some comparability among alternative proposals for SO_2 controls, it has been common to divide the total cost by the estimated tons reduced, and state the estimate on a dollars-per-ton removed basis. This is known as an *average cost*.

In evaluating costs and cost estimates, it is important to distinguish *average* costs from *marginal* costs, and this distinction has become particularly important in the case of emissions trading. The marginal cost is the highest cost per ton projected to be incurred by any individual source or source category. In most emission control programs, some sources will have lower costs than others. The average cost allows comparability across programs with different control objectives, while the marginal cost reflects the highest dollars per ton cost for any source, or even any incremental action at any source, included in that average. Thus, the marginal cost is always higher than the average cost. Two programs can have the same average cost, yet have substantially different marginal costs. Figure 2 provides an illustrative example. Thus, marginal cost should not be used to characterize the overall cost of a program. Market-based implementation heightens interest in marginal cost estimates however, because the marginal cost should be a good predictor of long-run allowance prices, which are important for planning of individual compliance strategies.

Figure 2. Marginal Cost Curves for Two Different Programs With Same Average Costs (AC) But Very Different Marginal Costs (MC) to Achieve a Specific Reduction Requirement



Allowance prices are the cost of buying allowances that one does not create for oneself (and, conversely, the return that one can get from selling allowances that one *has* created). Prices are thus very important to deciding on one's compliance strategy (e.g., whether to invest in control or to buy allowances from others). They also represent the compliance costs of those who choose only to buy allowances, but they do not necessarily equal *control expenditures*, which are the costs incurred by *sellers* to create the allowances through investment in physical control measures.

For analyses surrounding Title IV, we have seen a shift in emphasis from understanding total program costs (as embodied in average costs and total industry expenditures) to understanding likely market conditions (as embodied in marginal costs). The fact that both measures are stated in dollars per ton has led to substantial confusion contributing to misleading statements today. Both measures are important, but for different purposes, and more care is needed to clarify which one is being used, and which *should* be used, in specific circumstances.

Another distinction that has become important in analyses of market-based programs is the difference between *long-run costs* and *short-run costs*. Long-run costs include capital investments which, once committed or "sunk", cannot be undone, regardless of changes in market circumstances. Capital costs are always included in regulatory cost analyses, and are also included in most projections of average and marginal costs. However, once a source has made its compliance decisions and the capital cost part of its strategy is sunk, the only costs that can be avoided or reversed in response to unexpected market conditions are operating or "short-run" costs, such as for buying particular fuels or operating existing emission controls. These short-run costs can have a major influence on spot market allowance prices, since additional allowance purchases can avoid or reduce them but cannot avoid or reduce committed costs. Short-run costs may be quite different from the actual total costs of the control program, which include capital costs. This also can be confusing, since short-run costs, long-run costs, and allowance prices are all expressed in dollars per ton.

A third distinction, already mentioned, is the time frame in question. Is the cost estimate a Phase I cost, an early Phase II cost, or a later, "fully-implemented" Phase II cost?

Keeping the above distinctions in mind helps us to understand the confusion surrounding the costs of SO_2 reductions under Title IV.

ACTUAL COSTS OF TITLE IV ARE NOT DRAMATICALLY DIFFERENT FROM INITIAL COST PROJECTIONS

Evaluating the relationship between estimated costs and actual costs requires sound information on the estimates of costs prior to the start of Phase I, on what costs have been in Phase I, and on what costs are estimated to become by the time the Phase II cap is fully effective. Each is discussed in this section.

Cost Estimates of Title IV Prior to Legislation

The current lore is that initial cost estimates for Title IV were over $1000 per ton. This false perception appears to arise from confusion regarding marginal vs. average costs, and also regarding the amount of SO_2 reduction necessary under alternative proposals. Estimates in the range of $1000 per ton or more have always been for the marginal costs, i.e., costs associated with the most difficult-to-control sources. For example, a 1985 paper by Crocker and Regens clearly shows that control costs would exceed $1000 per ton only for scrubbing of units that are already using lower sulfur fuels.[8] Barring emissions trading, many units had been estimated to face such high costs, yet it was readily acknowledged that a well-functioning allowance market would equilibrate at far lower cost (and allowance price) levels. With an allowance market, the few units at the high-cost end of the range would have the flexibility to purchase allowances from lower-cost sources, who in turn would control more than would be required of them under the less flexible regulation. As flexibility became an increasingly important feature of regulatory proposals, it was viewed as less and less likely that any units might be forced into these more costly measures. In fact, when the Title IV legislation was being written, $1500 per ton was viewed as such an unlikely cost that it became the price set for a reserve supply of allowances that the government guaranteed to make available to new companies as a last resort in the event of hoarding.[9] The punitive charge associated with failure to comply was set at $2000 per ton, "several times more than the estimated average cost per ton of reducing SO_2 emissions."[10] This penalty was selected because it was viewed as being so much higher than any expected costs of obtaining allowances that it would serve as a deterrent of non-compliance.

Yardsticks used by policymakers to measure the total control costs of a program are the total annual cost and also the associated average cost per ton. Table 1 lists a number of such cost estimates for Title IV, starting at the time that its final form was emerging in legislative bills in 1989. The first column indicates the reference and the year in which the cost estimate was made. The rows are in chronological order and the estimates from the original studies have all been converted to a common year (1995 constant dollars). Since the cap is different for Phase I and Phase II, the costs will be different between the two time periods and are shown separately. The estimates for Phase II are all for the time the bank can reasonably be expected to have been essentially used up (a year that has progressively advanced from early in the decade to about 2010). Thus, 2010 is the first time period for which there is a comparable degree of stringency across the available Phase II cost estimates.

One can see from Table 1 that, even after inflating the early cost estimates to 1995 dollars, the average cost per ton estimates generally vary in a range of $150 to $300 per ton for Phase I and $225 to $500 per ton for full implementation in Phase II (2010). The estimates by ICF Incorporated were prepared for EPA. The estimates by Temple, Barker & Sloane, Incorporated (TBS) were "industry estimates" prepared for the Edison Electric Institute. The TBS estimates did not include provision for emissions trading. TBS noted that its cost estimates would be 20 to 25% lower if emissions trading were included in the estimate.[11] This adjustment is shown in the table for comparability with all the other estimates in Table 1, which did incorporate fully-flexible trading.

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[8]Crocker T. D.; J. L. Regens. "Acid deposition control," *Env Sci & Tech.* **1985**. *19(2).* pp. 112-116; (Table 2).
[9]Richard Schmalensee, personal communication.
[10]U. S. General Accounting Office. *Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost.* Washington, DC, December 1994; GAO/RCED-95-30; p 18.
[11]Temple, Barker & Sloane, Incorporated, *Economic Evaluation of H.R.3030/S.1490 "Clean Air Act Amendments of 1989": Title V, The Acid Rain Control Program*, slides prepared for The Edison Electric Institute, August 30, 1989, p. 4.

Table 1. Costs of SO_2 Reductions with Effective Emissions Trading: Estimates for Title IV and Associated Pre-Enactment Bills

(Original estimates converted to 1995$ using GDP deflator)

	Phase I			2010 (post-bank)		
	Annual ($b/yr)	Average ($/ton)	Marginal ($/ton)	Annual ($b/yr)	Average ($/ton)	Marginal ($/ton)
1989: White House *Fact Sheet: President Bush's Clean Air Plan*, 6/12/89.	.84	--	--	4.6	--	--
1989: TBS Inc. (for Edison Electric Institute) *Economic Evaluation of H.R.3030/S.1490,* 8/30/89.	--	--	--	6.0-8.5 (4.7-6.6 if w/ trading)	470-667 (364-517 if w/ trading)	--
1989: ICF Resources Inc. (for EPA) *Economic Analysis of Title V (Acid Rain Provisions) of the Administration's Proposed Clean Air Act Amendments (H.R.3030/S.1490)*, 9/89.	0.54-0.60	147-181	--	2.6-6.0	363-499	722-1005
1990: ICF Resources Inc. (for EPA) *Comparison of the Economic Impacts of the Acid Rain Provisions of the Senate Bill (S.1630) and the House Bill (S.1630)* (sic). [data for Senate Bill]	0.45-0.86	144-208	199-226	1.6-5.3	255-431	564-740
1990: NAPAP *1990 Integrated Assessment Report*, 11/91.	--	--	--	2.9-4.0	282-403	603-881
1992-3: EPRI, *Integrated Analysis of Fuel, Technology and Emissions Allowance Markets*, by Van Horn Consulting, *et al.* (EPRI TR-102510).	1.34	307	1238	2.3	335	516
1994: General Accounting Office. *Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost* (GAO/RCED-95-30).	1.17	299	--	2.2	227	--
1994-5: EPRI, *The Emission Allowance Market and Electric Utility SO_2 Compliance in a Competitive and Uncertain Future*, by K. White *et al.* (EPRI TR-105490).	0.90	283	879 (*)	1.5-2.9	288-336	389-566
1994-5: ICF Resources Inc. (For EPA) *Economic Analysis of the Title IV Req'ts of the 1990 Clean Air Act Amendments.*	1.07	235	--	2.3	253	533

(*) 50% lower if FGD is excluded.

Estimates of marginal costs also are provided in Table 1 even though they are not particularly useful for understanding a program's *total* control costs. However, marginal costs *are* useful in forecasting allowance prices, and often have been cited in trade press summaries of new studies. EPRI analyses have focused almost entirely on marginal costs because they are most relevant to business planning. Estimates of all three cost indicators (total dollars per year, average dollars per ton, marginal dollars per ton) are presented in the same table to help eliminate confusions. The following discussion focuses on the aggregate cost measures (total annual costs and average costs), while marginal costs are discussed in the section on allowance prices.

Actual Costs of Phase I

Table 1 documents how pre-implementation estimates for Phase I ranged from $0.5 to 1.3 billion per year, or $150 to 300 average cost per ton removed. Phase I started in 1995, with trading of allowances starting by 1993. There has been much scrutiny of market functioning in the trade press, privately, and by nonprofit research groups. Anyone who has given passing attention to the press is aware that allowance prices have been much lower than expected, with a particularly notable drop to approximately $70 per ton in March 1996. However, it is more difficult to observe how much has actually been spent on achieving the actual emission reductions of Phase I. This requires a detailed assessment of costs and emissions at over 445 units, relative to "what would have otherwise been".

The most recent in-depth Phase I cost assessment comes from MIT, funded by the National Acid Precipitation Assessment Program (NAPAP); some key results are shown in Table 2 (top row). MIT researchers find that the actual total costs of SO_2 control measures in Phase I have been $0.7 billion per year in 1995 for a reduction of 3.5 to 3.9 million tons of SO_2 relative to what would have occurred without Title IV. Thus, the actual long-run average costs of Phase I appear to be about $187 - 210 per ton.

Table 2. Actual Costs of Phase I and Updated Current Estimates of Phase II Costs (1995$)

	Phase I			2010 (post-bank)		
	Annual ($b/yr)	**Average ($/ton)**	**Marginal ($/ton)**	**Total ($b/yr)**	**Average ($/ton)**	**Marginal ($/ton)**
1997: D. Ellerman *et al.*, *Emissions Trading Under the U.S. Acid Rain Program* (MIT E40-279)	0.73	187-210	300-800	--	--	--
1997-8: EPRI, *The New Environmental Drivers: Challenges to Fossil Generation Planning and Investment,* prep. by K. White (TR-110261). **Base Demand:**	--	--	--	1.6-1.8	185-206	435-498 (*)
EPRI, *SO_2 Compliance and Allowance Trading: Developments and Outlook*, prep. by K. White (TR-107897). **Low Demand:**	--	--	--	1.1	--	276

(*) This range reflects base case assumptions with only the capital recovery period varied (10-20 years). Other uncertainties such as coal mine prices, transportation costs, and FGD costs, widen the range considerably, from less than $350 per ton to greater than $600 per ton.

MIT's analysis indicates that there have been errors in expectations during the market start-up that have raised costs above what could have been achieved with perfect foresight. A key cause appears to have been inability to anticipate the extent of the economic displacement of midwestern high sulfur bituminous coal by western low sulfur sub-bituminous coal, combined with the irreversibility of many control decisions involving capital investments with 3 to 4 year lead times and fuel contracts. Scrubber-related bonus allowances and outright political pressure to use flue gas desulfurization (FGD) further biased some strategies towards FGD, while many corporate planners initially took a cautious approach toward reliance on the untested allowance market, whose price dynamics were highly uncertain. The result was that aggregate "overcompliance" was greater than had been expected when companies were first making their compliance decisions and financial commitments.

At the same time there have been a number of significant reductions in the costs of individual control measures. For example, the cost of reducing emissions by FGD in Phase I has been 40% lower than 1990 estimates of that cost.[12] Low-sulfur coals are also substantially cheaper, particularly delivered to parts of the Midwest that have access to coals from Wyoming (Powder River Basin, or "PRB" coal). These were made cheaper by railroad productivity improvements, advances in mining technology, and heightened competition that occurred since the mid-1980's. Flexibility built into Title IV allowed utilities to take advantage of the suddenly cheaper low-sulfur coals as a compliance option, provided they could overcome obstacles to using sub-bituminous coals in boilers designed for higher rank coals. This option then increased FGD manufacturers' incentives to reduce their technology's costs to retain what they could of the market they had expected for their product. Further, the flexibility of Title IV increased the number of ways in which technology costs could be reduced: FGD could now be installed without costly backup systems that would have been essential if specific short-term control levels were mandated. Instead, a much less costly FGD design has been made possible (e.g., single large vessels), where any failures of the control equipment could be paid for via additional allowance consumption rather than strictly avoided through more costly capital investment (*e.g.*, in redundant spare vessels).

The market-based approach of Title IV was not the primary cause of reductions in control costs, but the approach did enhance the competition among all control methods to achieve cost reductions after exogenous events caused one control option (PRB coal) to become cheaper and more feasible. Under the trading approach, FGD costs probably fell more than might have otherwise occurred. Eastern low-sulfur coal likewise faced downward price pressure because of a failure to achieve widely expected market growth. Nevertheless, the control costs observed so far are still within the cost range originally anticipated. An interesting question is whether we will see greater benefits from these improvements in the long-run, as Phase II is implemented.

Updated Estimates of the Cost of Fully Achieving the Phase II Cap

The ultimate costs of Phase II are still unknown, but pre-implementation estimates of costs under a well-functioning market ranged between $1.5 to 6.5 billion per year, and average costs were generally estimated from $225 to 500 per ton (Table 1). The lower ends of the ranges were associated with lower levels of overall coal-fired unit utilization. Using these assumptions, the lower end of the range was $225 to $350 per ton. How much do we now think Title IV ultimately will cost in light of new information about load growth patterns, market performance, and technological improvement?

[12] Ellerman A. D.; Schmalensee R.; *et al*. *Emissions Trading Under the U.S. Acid Rain Program: Evaluation of Compliance Costs and Allowance Market Performance*; MIT Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology: Cambridge, Massachusetts, 1997; MIT E40-279, p 43.

Because of the unexpectedly large allowance bank (whose final size is still uncertain), full implementation of Phase II remains almost as far in the future as it appeared at the time that original Title IV cost estimates were being made. That is, in 1990, Phase II was expected to be fully implemented by about 2002, or about twelve years in the future. Eight years later, we find full implementation of the Phase II cap still to be about nine to twelve years away. Thus, forecasts of the ultimate total costs of Title IV remain a long-run projection, and not something that anyone can state with confidence even today.

EPRI (through K. White) has recently developed updated estimates of total costs of Title IV, shown in Table 2. As with the pre-implementation estimates, the key uncertainty that most affects the range is the demand for coal-fired generation. Higher growth in coal-fired unit demand strongly increases the costs of achieving the 9 million tons per year cap. Looking into the future, arguments can be made for both higher and lower levels of fossil plant utilization. Higher electricity demand growth may result from higher economic growth generally, and with increased electrification, as well as possibly from lower prices from deregulation. Lower electricity demand growth result from lackluster economic growth or even-greater conservation and end-use efficiency. Furthermore, future environmental regulatory initiatives such as those addressing $PM_{2.5}$ and CO_2 could dramatically alter the demand for coal-fired generation, and such a future is the primary motivator of EPRI's "low demand" case (bottom row of Table 2). The "low demand" case is not viewed as a likely demand scenario without further change in environmental regulations.

The middle row of Table 2 shows EPRI's long-run cost estimates using its updated base case demand for coal-fired generation. The long-run *average* cost centers around \$200 per ton, and the base case long-run *marginal* cost of meeting the SO_2 cap is between \$435 and \$498 per ton (1995\$), depending on whether the control investments are amortized over 10 years or 20 years. . These estimates take into account the various cost reductions that have been observed to date. The range of possible costs is much broader when considering various electricity, fuel and FGD market uncertainties. Even lower costs could occur with lower coal supply prices and reduced costs for FGD, due to both less conservative designs and technology advances. Even higher costs could occur with higher demand for generation from coal-fired plants or if investors became altogether averse to investing in additional FGD retrofits. Using an assumption of very low coal plant utilization (which EPRI considers likely only after significant new regulations are implemented), the marginal costs would be much lower, potentially below \$300 per ton. Because such low marginal costs are the result of a different regulatory future rather than a market-based uncertainty, this "low demand" case is shown on a separate row (bottom row of Table 2).

EPRI's best judgment of total *additional* costs (i.e., beyond Phase I measures already in place) to achieve the Phase II cap is \$0.84 to 1.04 billion per year. EPRI also finds that if demand for coal-fired generation were to be only half as much as EPRI's base case judgment, then the annual cost of additional compliance measures beyond Phase I actions might only be about \$0.4 billion per year. When the \$0.73 billion per year already incurred in Phase I is added to EPRI's estimates of additional costs to come, an up-to-date projection of the ultimate cost of the SO_2 program is \$1.6 to 1.8 billion per year for EPRI's base case. Much lower coal utilization growth, such as major new regulations might cause, could further reduce the number to as low as $1.1 billion per year.

Researchers affiliated with Resources for the Future (RFF) are developing an econometric model of SO_2 reduction costs. The econometric estimating approach used by RFF is quite different than the engineering approach used in all of the studies cited in Tables 1 and 2, particularly in that it estimates endogenous rates of change in cost and demand parameters. The RFF model is interesting because it fairly closely reproduces the early engineering cost estimates of Table 1 when applied using the assumptions about demand, prices, and technologies that were accepted around the time of those studies. It also fairly closely reproduces the actual costs of Phase I when actual compliance actions are input. At the same time, the model suggests that $0.2-0.3 billion per year of the actual costs in Phase I could be avoided (while still meeting the actual 1995 emissions levels) by further optimizing fuel choices. If so, this work suggests that possibly as much as 25% of the Phase I costs may not be permanently fixed, leaving room for some further downward revisions in the updated cost estimates discussed above. Although work is still in progress, RFF researchers' own "best judgment" of the ultimate costs of Phase II is $1.3 to 1.4 billion per year.[13]

In conclusion, the range for the most up-to-date estimates of the costs of Phase II has narrowed, reflecting today's better information about likely coal and power market conditions, but it overlaps with the low end of the original (prospective) range of estimates.

ALLOWANCE PRICES DO NOT NECESSARILY REFLECT ALL THE CONTROL COSTS

In contrast to expenditures on control measures, allowance prices *have* been much lower than originally expected. A well-functioning market that is in a long-run equilibrium would be expected to have allowance prices close to long-run marginal control costs. Long-run marginal costs for Phase I (including capital) in some instances exceeded $500 per ton. Nevertheless, until the latest run-up, allowance prices ranged between $80-120 per ton, and they have been lower. Most surprising is that allowance prices have fallen below actual *average* control costs. How can Phase I costs that are fairly consistent with initial Phase I cost estimates be reconciled with much lower-than-anticipated allowance prices? There are several keys to resolving this apparent contradiction.

In initially planning a compliance strategy, owners will consider *all* of the costs they will incur, or their *long-run* costs (including capital) and balance these costs against expected allowance prices. In particular, owners assess whether they can reduce emissions more cheaply (lower dollars per ton) than the market allowance price. Expected allowance prices, in turn, reflect the aggregate costs of all other owners relative to the cap. This is why most of the original projections of allowance prices were based on modeled long-run marginal costs.

[13]Personal communication, Dallas Burtraw, Resources for the Future.

In practice, there can be a number of institutional and social barriers to achieving the least-cost outcome. There is also a possibility that actual control costs will be poorly estimated and initial investments in control technology may not be the cost-minimizing ones. If the anticipated marginal cost is overestimated, there will be too much initial investment in control measures, and there will be more allowances available for sale than are needed to achieve the cap in a given year. As in any situation where there are more sellers than buyers in need, prices will fall. If the control costs were fully reversible (i.e., there was no sunk capital investment portion) then there would be a market adjustment where the most costly of the control measures would be shut down, and this would drive prices back up to the long-run equilibrium. However, there is a large degree of irreversibility about SO_2 control measures, and there are other, economic rather than compliance reasons for SO_2 reductions that, together, cause the excess supply conditions to persist in Phase I.

The short-run cost of running a scrubber reflects daily operating costs, such as reagent, power consumption and labor, but not the costs associated with recovering the capital investment. Provided the allowance price is greater than this short-run cost, the operator is not losing money by running the control equipment and creating more allowances, even if the initial capital investment is not being fully recovered. Thus, the short run marginal cost provides one benchmark for how low prices can go before people stop creating more of them. For capital-intensive measures like FGD, this point can be considerably lower than the long-run marginal cost. If prices fall below these short-run costs, operators would do better to buy allowances, which in turn would bring buyers back into the market and buoy prices back up to the short-run marginal cost.

A second consideration is that, for many potential sellers of allowances, the cost of generating allowances is zero and they may have no short term need for them. An example is a company that happened to come into compliance earlier than Phase I because of increasingly lower costs of delivering western low-sulfur coal to mid-western power plants (due to falling rail rates), or because of the need to comply with more stringent state regulations. For these sellers, the pricing question is not what the allowances cost, but what they are worth to others, or to themselves for future internal use. This depends not only on the current short-run costs of reducing emissions at other units, but more importantly on estimates of Phase II costs and on assumptions about how much to discount future costs to present values.

Thus, the ability to bank allowances for future years also can influence today’s market price of an allowance, with the future value of banked allowances serving as another benchmark below which prices would tend not to drop. If the present value of expected, future allowance prices is greater than today’s operating costs, then it makes sense to spend the operating costs today to create allowances that can be banked for future sale, or for future internal use. This additional financial consideration siphons off some of what would otherwise be excess allowances in the current year’s market, and thus drives up the current allowance price until it comes in line with discounted future expected prices. Of course, there is no universally accepted “expected Phase II price” and no uniform agreement over what discount rate to apply, making this second benchmark very difficult to estimate with any precision.

Interpretation of Current Allowance Prices

By the end of 1995, it became apparent that overcompliance had been substantial: the 445 units affected by Phase I of Title IV emitted only 5.3 million tons of SO_2 relative to a cap in 1995 of 8.7 million tons.[14] The actual amount of banking, 3.4 million tons, exceeded earlier estimates by as much as 1.5 million tons.[15] The fact that the excess allowances could be saved for a future day when the cap will be more stringent is what gives these allowances financial value, rather than the cost of meeting today's cap.

If Phase II control costs turn out high enough, Phase I "overinvestment" in control may yet generate a return despite current allowance prices that are well below long-run control costs. How high do Phase II prices need to go for it to be sensible to create or buy allowances today and bank for the future? If we take an average price in early 1998 of about $120 per ton, and assume that the required real rate of return is 8%, then this price is consistent with expected allowance prices in 2008 to 2010 of $259 to $302 per ton (in constant dollars). With equally plausible, higher discount rates, a $120 price is consistent with even higher future marginal costs (around $500), as is the summer 1998 allowance price of $190 with a lower discount rate. This sort of comparison should not be overdone, however, because of the many uncertainties involved in understanding the appropriate discount rate and the expected Phase II price, such as effects of electric deregulation and potential new environmental regulations.

While the range of recent and current allowance prices do have linkages to underlying costs of controls, it should be clear that these allowance prices:

- Do not directly reflect all of the actual control costs incurred to date under Title IV; and
- Are not *directly* comparable to any of the initial or updated estimates of long-run Title IV costs.

Yet, these allowance prices are telling us something, although it is not what total control costs have been so far. Current prices reflect other aspects of control costs:

1. *Today's short-run marginal costs.* In the short-run, the considerable FGD capacity now installed creates an effective floor to allowance prices equal to FGD's operating cost of about $50-65 per ton.[16] This cost is consistent with the very lowest allowance price experienced of about $70 per ton. Slightly higher allowance prices in the recent past are consistent with some plants' short-run cost of switching to low-sulfur coal, which is based on the price premium for coals with lower-sulfur content, which has been around $100-120 per ton of SO_2 reduced. Thus, the current short-run marginal cost of switching has been consistent with the allowance price, and it is likely to remain so. With a current allowance price of nearly $200 a higher coal sulfur premium is clearly implied, but it is also possible that the price of allowances may fall back to a lower level.

[14] Ellerman A. D.; Schmalensee R.; *et al., op. cit.* p 15.
[15] The rate of banking has declined by nearly 2 million tons between 1995 and 1997 due mostly to the drop in FGD and other bonus allowance awards.
[16] *Ibid,* Table 8 and p 49.

2. *The present value of today's expectation of future compliance costs*. Updated estimates of discounted costs in Phase II are also consistent with current spot prices (both high and low!), because of the significant uncertainties about demand in Phase II and the discount rate to be applied. In particular, uncertainties about future regulatory requirements that might affect coal generation—and therefore the future value of an allowance—may create a greater risk premium in the discount rate than otherwise would be justified.

WHAT WILL HAPPEN IF REGULATORY REQUIREMENTS CHANGE?

It is evident that changes in environmental regulations affecting coal will not only affect future compliance costs, but that concern about those changes could influence allowance prices today. Those effects depend on the regulation in question.

The new NAAQS for fine particles ($PM_{2.5}$) is one of the regulatory changes that could substantially affect expectations regarding the SO_2 allowance market. Because SO_2 emissions contribute to ambient fine particulates, they may be further regulated. If the current SO_2 cap were to be halved by 2010 (a level suggested by the Environmental Protection Agency in its regulatory impact analysis for the new $PM_{2.5}$ NAAQS), costs of control would increase substantially. EPRI has estimated this control cost at an additional $3 to 5 billion per year on top of the costs of Phase II already expected, and finds that marginal costs could be as high as $1,350 per ton, barring significant retirements or repowering.[17] The stricter cap would greatly reduce the range of options, since the sulfur content of coals simply does not go low enough, and many units would have to scrub even with trading.

How might such additional NAAQS-related control costs affect future allowance prices (and hence current market behavior as well)? It depends on how the new regulations are implemented. If the Title IV cap-and-trade program were to be retained, but allowance allocations cut in half through new legislation, then allowance prices would rise much higher than was expected when Phase I decisions were made. If, instead, additional SO_2 restrictions take the form of <u>local</u> requirements laid on top of the present Title IV cap (as might be expected for regulations directed at ambient air quality), then this greater stringency would render the Title IV cap meaningless. It would create a flood of Title IV allowances at the same time that it would shrink the pool of potential buyers, greatly undermining allowance values. Even though expected future allowance prices would plummet, costs to reduce SO_2 would increase. Current allowance prices (which depend in part on future allowance prices) would also be driven down if this form of future regulation were anticipated. Thus allowance prices could remain low or fall lower, but for reasons wholly unrelated to Title IV's control costs or to the benefits of allowance trading.

Although less imminent, any cap imposed on carbon dioxide (CO_2) emissions to address climate change would also affect SO_2 allowance prices. Two prominently suggested approaches for reducing U.S. carbon emissions are reducing energy consumption (including electricity) overall, and replacing coal as a fuel for electric generation. Either strategy would reduce demand

[17]EPRI; *The New Environmental Drivers: Challenges to Fossil Generation Planning and Investment*; prepared by K. D. White; Palo Alto, California; March 1998; TR-110261, p.4-23.

for coal-fired generation, thus reducing potential SO_2 emissions and the need for allowances. Overall, this result would dampen growth in allowance prices, but lower prices would not reflect lower SO_2 control costs, and should not be attributed to the benefits of allowance trading.

LESSONS FOR OTHER POSSIBLE EMISSIONS MARKETS

Based on the successes observed with market-based approaches such as Title IV's SO_2 allowance trading program, there is much discussion of the benefits of applying emissions trading to achieve other environmental goals. The most immediate example is trading of NO_x emissions proposed by EPA as part of a national program to achieve the ozone NAAQS. Another commonly cited example is trading of CO_2, or of greenhouse gases generally, under a climate change initiative. There are many lessons from the Title IV experience that should be more fully deliberated when considering such other emissions markets.

We will not attempt to sort out all of these emerging lessons here. However, we will note that the cost reductions observed in the SO_2 trading experience will not necessarily be repeatable in other markets. One key feature of the SO_2 market would need to be present again. The SO_2 cap was set at a level that left a wide range of options for many individual sources, and more importantly, for all affected sources in the aggregate. An approximate 50% overall emissions reduction was required in a situation where there was a technologically-proven option that could achieve reductions of 95%. Combined with that was the presence of a wide continuum of lower percentage reductions possible via fuels with many different sulfur content levels. Thus, there was room for applying the best available control measures on only a small fraction of the regulated units, where they would be truly cost-effective and, more generally, for meaningful competition among a diverse set of options. A more stringent cap would have reduced this flexibility, and price competition among suppliers of control options. For example, the ability to take advantage of cheaper low-sulfur coals from the West would have been greatly diminished if aggregate required SO_2 reductions had been substantially greater than 50%.

CONCLUSION

Recent statements by policy makers and even by policy analysts suggesting that the cost of the SO_2 control program known as Title IV has actually cost only about one-tenth the initial cost estimates are based on inappropriate comparisons. Title IV has been successful in many ways. Its costs have declined relative to initial expectations. Some of these cost reductions can be attributed to using a market-based tool for this program. Other cost reductions probably would have occurred anyway, but the flexibility of Title IV made it easier for utilities to take advantage of fundamental market changes and to avoid a rigid, unnecessarily expensive control program. However, a proper assessment of the actual costs of Title IV (much of which still depend on projections of future events) indicates that the total costs of this program remain at the low end of, but still within, the initial cost estimates. Claims that Phase I has been exceptionally cheap are largely a false impression created by conceptually inappropriate comparisons of early allowance prices with various measures of cost. In fact, current estimates of Phase II compliance cost appear likely to be farther below the average of initial cost estimates than is the case for Phase I, although the jury is still out on Phase II costs, as indicated by recent allowance price fluctuations. We can and should be pleased that these costs are lower than predicted, but the costs associated with Title IV are still significant and real.

Market-based regulatory approaches are here to stay, making it important that we all learn to be more precise in labeling and evaluating the costs and the market indicators. Emissions trading has been proven to be a very effective tool in so far as Title IV is concerned, but it is not a panacea that inevitably makes costs of emissions control simply disappear into thin air. Neither is it fair to say that the Title IV experience shows that initial cost estimates are not to be trusted for guiding policy decisions. After accounting for the form of a regulation's implementation, the main determinant of cost remains the stringency of the measure.