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Incorporating Uncertainty into Electric Utility Projections and Decisions

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INTRODUCTION

Uncertainty is an inherent part of the business environment. There is uncertainty in technology, sales, fuel prices and government regulation. One problem facing business forecasters is to assess probability distributions over ranges of outcomes. This is of course difficult, but this problem is not the focus of this paper. This paper instead focuses on how electric utility companies can respond in their decision making to uncertain variables. Here we take a mean-variance type of approach. The "mean" value is an expected cost, on a discounted value basis. We assume that management has risk preferences incorporating a tradeoff between the mean and variance in the utility's net income.

Decisions that utilities are faced with can be classified into two types: ex ante and ex post. The ex ante decisions need to be made prior to the uncertainty being revealed and the ex post decision can be postponed until after the uncertainty is revealed.

Intuitively, we can say that the ex ante decisions provide a hedge against the uncertainties and the ex post decisions allow the negative outcomes of uncertain variables to be partially mitigated, dampening the losses.

Some examples can be given. Investment decisions in new capacity are ex ante decisions. However, technologies with shorter lead times have an advantage in that more information may be available prior to making the investment decision. An example of an ex post decision is how the system is operated i.e., unit dispatch, and in some cases switching among types of fuels, say with different sulfur contents. For example, if gas prices go up, natural gas combined cycle units are likely to be dispatched at lower capacity factors. If SO_2 emission allowance prices go up, a utility may seek to switch into a lower sulfur coal.

Here we assume that regulated electric utilities do have some incentive to lower revenue requirements and hence an incentive to lower the electric rates needed for the utility to break even, thereby earning a fair return on invested capital. This assumption is discussed in more detail below.

This paper presents the general approach first, including applications to capacity expansion and system dispatch. Then a case study is presented focusing on the 1990 Clean Air Act Amendments including SO_2 emissions abatement and banking of allowances under uncertainty. It is concluded that the emission banking decisions should not be made in isolation but rather all the uncertainties in demand, fuel prices, technology performance etc , should be included in the uncertainty analysis affecting emission banking.

GENERAL APPROACH

Part of the objective function for the utility, the "mean value" part, is the discounted value of revenue requirements, denoted here by DV. We also know that emission allowances need to enter into the decision process. With the adjustment for emission allowance treatment we can denote the adjusted mean value term by AdjDV. The exact incorporation of allowances into the decision process will depend on expected regulatory and income tax treatment of allowances. One way to incorporate allowances in this decision framework is to value changes in allowances at the expected market value in the year that the change takes place, i.e., buying or selling.

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A variance term typically looks like $\sum Pr_j(X-\bar{X})^2$ where the summation is over all uncertain outcomes. Here we append a variance like term to the objective function:

$$J = AdjDV + w\sum_j Pr_j\,\varphi\,(loss_j)$$

where

Pr_j is the probability of the j^{th} outcome.

$loss_j$ is an index of losses under the j^{th} outcome

φ is a monotonically increasing convex loss function, and

w is the mean-variance tradeoff weight.

For normalization, the objective function can be modified as follows:

$$J' = AdjDV + w\sum_j Pr_j\varphi\,(loss_j/AdjDV)$$

An appendix is available from the author giving the necessary conditions to minimize the objective function for utility capacity expansion, dispatch and pollution compliance under uncertainty. These necessary conditions are then solved for the optimal decisions.

We are already prepared to draw some conclusions based on this loss function. We will discuss three aspects: (1) endogenous risk premiums on capital intensive new capacity, (2) the portfolio advantage of banking emission allowances and (3) mitigation from unit operations.

Often a capital-intensive technology such as a base load coal unit or a nuclear plant or even a renewable electricity source, is assigned a higher cost of capital just because it is capital intensive and presumably thereby exposes the utility company to greater risk. This general idea fails to recognize the continuous nature of the risk exposure when making capital intensive investments. It could be that a single base load unit, which may be replacing existing capacity, has very little market risk associated with it. However, if the utility's forecasting department projects rapid load growth over 15 years and proposes immediately to start building many long lead time capital intensive projects, then the utility does face the risk that the projected electricity sales will not be as strong as projected. Like other economic decisions the appropriate decision rule is based on marginal conditions. Given that the utility has or is building N megawatts of base load capacity, what is the expected cost savings and additional risk exposure by building one more unit? The two part objective function specified above allows this marginal risk evaluation in making the capacity expansion decisions and technology choices.

The dispatch of units is a different kind of problem because many uncertainties, except for short term weather changes or unit forced outages, are known at the time of the dispatch decision. Hence dispatch is an ex post decision with respect to load growth, fuel prices and technology cost and performance. By redispatching, good outcomes affecting some units can be exploited by using those units more, and bad outcomes can be mitigated by using those units less.

The role of SO_2 emission allowance banking in the utility's portfolio can also be illustrated in terms of the above objective function. Recall that outcome j is a joint outcome over all random variables. Hence the probability of this joint outcome is P_r (emission allowance prices, demand, fuel prices, nuclear generation, etc.). It is the correlation between these random variables which leads to the possibility of excess holdings of SO_2 emission allowances to help lower the risk exposure in the utility's net income. For example, the utility may be uncertain regarding how much generation it will be able to obtain from its nuclear plants in the post 2000 period (Phase II of the Clean Air Act Amendments). However, what happens to a particular utility's nuclear generation is probably correlated with what happens to nuclear generation in the country as a whole, and this is correlated with the demand for coal generation which will bid up the price of emission allowances. Hence the contingency of losing income due to poor nuclear performance is negatively correlated with the contingency of capital gains on the utility's banked allowances (or allowances which it has purchased on futures markets, if such futures markets materialize). This lowers the variance loss term in the objective function above.

UNCERTAINTIES RELATED TO THE SO_2 ALLOWANCE MARKET

The effectiveness of SO_2 emission allowance trading under Title IV of the 1990 Amendments to the Clean Air Act (CAA) is of great interest due to the innovative nature of this market incentive approach. However, it may be a mistake to frame the compliance problem for a utility as a decision to trade or not. Trading of allowances should be the consequence, not the decision. The two meaningful decision variables for a utility are the control approaches chosen for its units and the amount of allowances to hold in its portfolio of assets for the future. The number of allowances to be bought or sold (i.e. traded) is determined by the emission reduction and banking decisions.

Our preferred approach is to think of the problem in terms of the ABC's of the 1990 CAA Amendments: abatement strategy, banking, and cost competitiveness. These three concepts are elaborated more in Hanson[1].

Abatement

A utility minimizes its costs whenever the marginal abatement cost (constructed from its alternative control options) is equal to the market evaluation of allowances. This gives a deterministic rule for the least cost control option for each unit in a utility's system.

It should be recognized that much of the efficiency gains-from-trade among units can be achieved by trades within the utility company or among the members of the utility's power pool, within which power is routinely traded. Hence the absence of a large amount of trading between regions of the country need not imply that the CAA trading provisions are ineffective in achieving SO_2 reductions at lower cost.

Banking

Banking can be a part of a strategy to minimize expected costs. That is, a strategy that minimizes expected costs may be to over comply with the Phase I standard which is not tight in favor of lowering compliance cost in Phase II by utilizing banked allowances. However, the rational banking decision by utilities is more complex because of the uncertainty in Phase II allowance prices. A utility may wish to hold extra allowances in its portfolio to hedge against a higher than expected need in Phase II for fossil fuel generation. Such a strategy can be shown to lower the overall variance in the firm's portfolio[2]. Partially offsetting this desire to bank allowances for risk hedging reasons is the incentive to sell any unused allowances whenever their expected growth rate in price is less than the utility's cost-of-capital. That is, the expected return on a utility's holding an allowance is the expected capital gain. For example, if a utility anticipated running out of its stock of banked allowances in the year 2005 and it expects the price of an allowance to be \$750 (1990\$) per ton in 2005, the discounted present value of purchasing an allowance in 1993 for use 12 years later at a real interest rate of 8% is $750/(1.08)^{12}$ or under \$300. This discounting phenomenon helps to explain the low prices for current allowance trades that people are now discussing.

The market equilibrium for the (rising) price of allowances and for the extent of Phase I SO_2 reductions and hence the supply of allowances to be banked will depend on the abatement cost curves for all affected units and the utility's demand functions for holding allowances for the future.

Cost Competition

Many analysts have claimed that utilities will decide not to trade in the allowance market. This is generally attributed to electric utilities being a regulated industry. However, it is our view that utilities do have incentives to lower their costs, as measured by levelized revenue requirements, due to competitive pressures, uncertainty in the ability to pass costs to customers in rate cases and due to the intense public scrutiny given to utility decision making. Emission trading can help utilities lower their revenue requirements.

There are three slightly different variations on this theme of regulatory distortions interfering with emission trading. One theory attributed to Averch-Johnson in the economics literature claims that if a utility earns an above normal risk-adjusted return on its investments, it will seek to make capital intensive expenditures, such as FGD equipment. The second variation is that even if utilities only earn their cost-of-capital on investments, since they are given the opportunity to pass their costs to their customers, they will not be concerned about their costs. Since the purpose of emission trading is to improve efficiency by lowering costs, the utility may be indifferent as to trading. The third variation deals with uncertainty in state regulatory commission treatment of the buying, selling, or holding of allowances.

It would appear that the regulatory treatment of interutility power exchanges should be a guide to the regulatory treatment of allowances, but there are some differences, namely, allowances can be banked for the future and held as part of the utility's asset portfolio.[1,2]

Utility Model Simulations

The Argonne Utility Simulation Model (ARGUS90)[3] an earlier version of which was used as one of the modeling tools for the National Energy Strategy[4,5], has now been re-designed to represent the provisions of the 1990 CAA Amendments. Specifically the new model version represents unit compliance decisions, utility incentives for banking and the resulting market equilibrium allowance price path over time, SO_2 emission paths and associated reductions costs. The model can also be used to represent the effects of the barriers to trade identified by some analysts and to simulate uncertainties. National and regional results from the model can be obtained from the author.

Origins of the 1990 CAA Amendments

Following a rising tide of environmental awareness in the United States during the 1980s and a decade of research and Congressional debate on acid deposition controls, the Bush Administration took a lead in the reauthorization of the Clean Air Act. Compromise legislation was finally crafted among the Administration's proposed bill, a House version, and a Senate version, which resulted in the 1990 CAA Amendments, signed by the President in November of 1990. An overview of the new CAA is described elsewhere[6].

Acid rain control was a contentious issue during the 1980s because of the skewed divergence of regional interests and the perceived high control cost, estimated by NAPAP to be about $4 billion per year.[7] Emissions are not evenly distributed among the regions of the U.S., but tend to be concentrated in the Mid-Atlantic, Midwest and the South (for a map of these regions see Figure 1). Figure 2 shows that the utility sector is the most significant contributor to SO_2 emissions except for the West South Central and Pacific South West where non-utility sources dominate (mostly from sources such as copper smelting).[8] NO_x emissions also are not evenly distributed regionally as shown in Figure 3. NO_x emissions, unlike SO_2, are not dominated by utility sources, although the utility sector is a major contributor to NO_x emissions.[8]

A system of tradable sulfur dioxide (SO_2) allowances was adopted as the central approach to acid deposition reduction. This approach was recommended in a study sponsored by Senator Wirth, CO, and Senator Heinz, PA, entitled, Project 88 Harnessing Market Forces to Protect Our Environment: Initiatives for a New President, Dec. 1988.[9] The study participants included not only academic economists but also business leaders and representatives of environmental groups, such as the Environmental Defense Fund. The adoption of this market-based approach helped achieve the passage of the CAA legislation in Congress and hopefully may foreshadow considerably more reliance on market incentive approaches to other environmental regulations in the future. A second round followup Project 88 study has recently been completed.[10]

Market approaches, such as tradable emission allowances, can lower costs, encourage pollution prevention, stimulate the development of new abatement technology, and provide a level playing field among emission reduction sources which increases efficiency. These characteristics of market approaches are contrasted with technology or regulatory standards. For example, if the law requires industry to install the "best available control technology," then there may be an incentive not to innovate in ways that reduce pollution because the government may proceed to make emission standards more stringent. Also, more stringent standards on *new sources* than on *existing sources* introduces the bias to continue to operate existing equipment after the time at which it would have been economic to modernize and replace the equipment. Hence, New Source Performance Standards (NSPS) have been accused of lowering investment and reducing economic growth. In contrast, the level playing field under a market approach encourages new, efficient investments.

Acid Rain Control of Coal-Fired Electric Utilities

The acid deposition title, Title IV, of the 1990 CAA Amendments creates a market incentive system based on SO_2 "emission allowances." An allowance must be obtained for each ton of SO_2 emitted, as will be described below. Once allocated by the EPA, allowances can be traded among companies or reserved for future use or to hedge against higher emission allowance prices. Allowances are tradable between years, a concept called "emission banking." Allowances cannot be used for years prior to their designated issuing year. A two phase approach is also innovative, as are its use of incentives to encourage Flue Gas Desulfurization (FGD) and the adoption of Clean Coal Technology (CCT).

The acid rain title is scheduled to cut sulfur dioxide (SO_2) emissions from electric utility power plants from 16 million tons in 1985 to about 9 million tons in the year 2000. The ambient air quality standards for SO_2 had already reduced SO_2 emissions since their peak national level of 29 million tons from all sectors in 1977 to about 23 million tons in 1990 (see Fig. 4). If the high emitting power plants, many of which burn high-sulfur midwestern coal, were to retire at age 30, then SO_2 emissions would rapidly decline in the 1990's and perhaps no Title IV would have been necessary, because New Source Performance Standards (NSPS) would have assured very low emission rates for replacement units. However, the general trend in the electric utility industry has been to refurbish, life extend or repower existing power plants with newer combustors.

Marketable Emissions Allowances

Emissions trading and banking provide cost savings over mandatory technologies in achieving long run environmental goals. These gains are achieved because rather than mandatory control technology, firms gain the flexibility to reduce pollution by choosing among (1) the cheapest technologies, (2) alternative fuels, (3) alternative schedules in lowering emissions. Factors which will affect the least cost choice are plant design suitability for retrofit, land availability, economies of scale in abatement technology, access to alternative fuels including differences in competition in transportation to power plants at different locations, and alternative local air quality requirements.

Gains from trade can be illustrated with a simple example. Suppose 100 tons of emission reduction is needed to meet the environmental objective. Suppose plant A has a marginal abatement cost (MAC) of \$300 per ton and plant B has a MAC of \$500 per ton. Under a uniform roll back policy each plant would reduce emissions 50 tons at a total cost of \$40,000. However, suppose each plant is issued 50 tons of tradable emission allowances. Then plant A sells its allowances to plant B for say \$400 per ton. Plant A then reduces emissions 100 tons at \$30,000 and gains \$20,000 in revenue from the sale of allowances. Thus, the net cost to A of the reduction in emissions is \$10,000. Plant B's \$20,000 cost of purchasing allowances is less than the \$25,000 it would have had to pay to reduce emissions by 50 tons. The total cost of the 100 ton emission reduction is \$30,000 rather than the \$40,000 cost of the uniform rollback policy.

Under the new CAA, allowances are issued <u>gratis</u> to existing polluting utility units based on thei. "baseline" fuel use as measured by the annual average of 1985, 1986, and 1987 Btu consumption. The basic Phase I allowances are calculated as 2.5 lb SO_2 per 10^6Btu times the unit's baseline, and the basic Phase II allowances for the larger, dirtier units are calculated as 1.2 lb per 10^6Btu times the unit's baseline, though allowance allocations are generally not larger than those required to meet historical emission rates. Additional Phase I and II allowances are also distributed based on other considerations. In Phase I, a maximum of 3.5 million tons of SO_2 allowances are to be awarded to units installing scrubbing (FGD) by year 1997. These units can maintain their existing emissions for the first two years of Phase I and then after 1997, also receive '2-for-1' bonus allowances for emission reductions beyond those required by the 1.2 lb/10^6Btu limit.

As the CAA plays out over time, it is expected that utilities will in fact choose to bank Phase I allowances for use in Phase II. The incentives for installing FGD under the CAA 1990 Amendments, along with pressure by mining interests in the midwestern high sulfur coal producing states to scrub rather than switch to low sulfur coal, will result in banked allowances for use in Phase II. For another reason, assuming that low sulfur coal prices are not bid up too high in Phase I, a unit may be able to switch fuels and achieve an emissions rate of less than 2.5 lb/10^6Btus. The banked emissions will lower the cost of complying with the more stringent rate effective in Phase II. For example, a utility could scrub those of its units that are the easiest to retrofit FGD and then burn low or medium sulfur coal in the remainder of its units, thereby banking allowances to cover any excess emissions in Phase II.

Bonus allowances of 0.53 million tons per year are also provided in Phase II to be awarded to units with low capacity factors in the baseline years and to units which would be otherwise penalized because they were already low emitting units as of 1985. Any excess allowances can be traded or used in conjunction with new growth in coal-fired generation. Utilities which contract for approved CCT may be awarded a 4 year Phase II extension.

Fig. 5 shows qualitatively the anticipated paths for emissions and allowances. Allowance awards are the highest in 1995 and 1996 due to extensions for Phase I FGD. The allowances in 1997-1999 are based primarily on an allowed 2.5 lb/10^6Btu emission rate applied to the baseline fuel use for 110 affected plants in Phase I as defined in Table A of the 1990 CAA Amendments. The allowances in Phase II are based on 1.2 lb/10^6Btu or less, as applicable, with a four year extension for approved CCT. Hence as illustrated in Fig 5, allowances are issued at a much higher rate early in the program. Although actual emissions will be decreasing over time, they will also decrease at a slower rate than allowances, which thereby implies an accumulation of banked allowances in Phase I and the using up or depletion of these banked allowances in Phase II (see Fig. 6) The time at which banked allowances are eventually used up (i.e. when the market regime switches to one of annual market clearing) is denoted by T* in Figures 5, 6, and 7. (Note that Figures 5 - 8 have arbitrary y-coordinates.)

Hedging Risks

The market price of allowances is expected to rise steadily over the course of Phase I and II through the middle of the next decade (see Fig. 7). This is because (as illustrated in Fig. 6), there is expected to be excess stock of allowances held and the only advantages to holding allowances instead of acquiring them in the future as needed would be capital gains derived from an allowance price expected to rise or the holding of allowances for hedging against uncertainty in the escalation rate of allowance prices. The actual time path of prices will depend not only on technical economic factors such as fuel switching costs, but also the motivations of market participants. Risk aversion provides a motive for electric utilities to bank allowances, thereby increasing the current price of allowances. But forward contracts and futures markets for SO_2 allowances, such as those proposed by the Chicago Board of Trade (CBOT), may also influence allowance prices by facilitating the entry of speculators who are willing to bear some of the risks of risk averse utilities.

Increased entry of non-utility financial market participants would tend to reduce current allowance prices as illustrated in Fig. 7.

Major uncertainties affecting allowance prices include: future gas supply and deliverability, success of renewable energy, effectiveness of demand side management programs (DSM), recovery of the nuclear industry, CCT performance and future penetration, the extent of low sulfur coal reserves, future electricity demand growth, and regulatory risk. These uncertainties all affect required coal- fired generation during Phase I and Phase II and hence they effect the demand for allowances. The holding of allowances can be used to hedge against these uncertainties. Formulas for the optimal holding of allowances based on variances, covariances and relative risk aversion have been derived elsewhere.[1,2] By lowering costs and risks everyone can gain, including rate payers and utility shareholders. If a formal market exists for allowances, it may be more difficult for governments to make regulations which inhibit electric utilities from making least cost abatement choices, since the existence of market prices makes the cost of alternatives clear to the public and to all involved.

Abatement Cost Functions and Emission Reduction

The extent of emission reductions in Phase I and Phase II will be a function of the market price for allowances. A firm can either reduce emissions using fuel switching or scrubbing, or use allowances. The rule-of-thumb in economics is that it is cost effective to reduce emissions up to the point where marginal abatement costs, MAC, equal the price of allowances, PA. For example, if MAC is greater than PA, it would be cheaper for the firm to increase emissions and buy allowances.

Figure 8 illustrates the total abatement costs for SO_2 reduction, through switching to lower sulfur coal or retrofitting a scrubber for a typical coal-fired power plant. As Fig. 8 illustrates, scrubbing is typically more economic at higher reduction percentages. The slope of the total abatement cost curve is the marginal abatement cost, MAC. The firm can observe current allowance prices, PA, but it must forecast future values for PA. The value of PA used by the firm for planning purposes is taken to be the slope of a tangent line drawn in Fig. 8.

The solution for the amount of emissions reduction which minimizes costs is the point at which the price of allowances, PA, equals MAC. In Fig. 8, when the price of allowances is low, the solution for emission reduction is shown as point (a) and fuel switching is used. When the price of allowances is higher in Phase II, a solution is illustrated as point (b) in Fig. 8 at which the unit finds it economic to install a scrubber. Rising allowance prices over time is consistent with increased stringency of control with a higher MAC in Phase II vs. Phase I (see Fig. 7). Whether the utility company will want to buy allowances will depend on the number of allowances it was originally given and its motive to bank allowances as a hedging strategy.

Marginal abatement costs, MAC, can be calculated using standard utility financial economics based on levelized revenue requirements. The MAC for timing issues, i.e., whether it is lower cost to install a scrubber in 1995 or 2000, given rising allowance prices, PA_t, is calculated as the "annual rental price" of using the FGD capital requirement offset by the annual savings in fuel and allowances consumption due to installing the scrubber in 1995 instead of in 2000.

Detailed simulations for MAC in Phase I and Phase II have been calculated in ARGUS90 and in a comparable spread sheet system for actual utility units.

Allowances and Coal Market Price Path Interaction

Interestingly, marginal abatement costs, MAC, are, in theory, proportional to the low sulfur coal price premium, the additional amount paid for coal per unit reduction in sulfur content. Let PC(S) denote delivered coal prices as a function of sulfur, where we define S in terms of the resulting lb $SO_2/10^6$Btu emission rate. The MAC is just the extra price paid for lower sulfur coal from which it follows (adjusting for a change in units)

$$MAC = (-\ 2000\ \text{lb/ton})\ \Delta PC/\Delta S$$

Since the condition PA = MAC provides the cost minimizing compliance strategy and emissions reduction as a function of the allowance price, PA, then

$$PA = -\ 2000\ \Delta PC/\Delta S.$$

Therefore, market equilibrium low sulfur coal prices are closely connected with market equilibrium allowance prices. Bidding up allowance prices is equivalent to bidding up the price premium on low sulfur coal. Hence, observing the sulfur price premiums in the coal market is a proxy for emission allowance prices.

UNCERTAINTIES IN OTHER TITLES OF THE CAA

The presence of market uncertainties affecting the future price of allowances has been discussed as a motive to hold allowances to hedge against these risks. Another source of uncertainty is possible changes in government regulations or the stringency with which they are enforced. Other programs under the CAA which can potentially have a large impact on electric utilities besides Title IV on Acid Deposition Control are Title I effecting SO_2, NO_x and ozone nonattainment, Title III of the 1990 Amendments on industrial air toxic emissions, and Title V on the new comprehensive permitting program. The new permitting program may be a vehicle to enforce the 1977 CAA Amendments setting a national goal for no man-made visibility impairment, with reasonable progress to be made toward this goal over time. Either the PSD program can be used to enforce further controls on emission sources, or air quality related values such as visibility or sensitive ecological areas can be protected through federal intervention in the state permitting process. Based on recent trends in rejecting new source permits and new regulations promulgated by the Department of Interior (Federal Register Feb 5, 1992) intervention by the Federal Land Manager to require more stringent emissions caps on existing sources is expected under the new permit program of the 1990 CAA Amendments.

Unfortunately, it appears that, because sulfates are carried over long distances rather than deposited locally, only a small percentage of the contribution to visibility impairment comes from local sources. Based on Argonne National Laboratory's Advanced Statistical Trajectory Regional Air Pollution (ASTRAP) model, relative source contributions arriving at selected National Parks have been estimated.

CONCLUSIONS

The implications of the general principles presented in this paper on least cost emission reductions and emissions banking to hedge against risk are being simulated with the ARGUS90 model representing the electric utility sector and regional coal supplies and transportation rates. A rational expectations forecast for allowances prices is being computed. The computed allowance price path has the property that demand for allowances by electric utilities for current use or for banking must equal the supply of allowances issued by the federal government or provided as forward market contracts in private market transactions involving non-utility speculators. From this rational expectations equilibrium forecast, uncertainties are being explored using sensitivity tests. Some of the key issues are the amount of scrubbing and when is it economical to install it, the amount of coal switching and how much low sulfur coal premiums will be bid up; and the amount of emission trading within utilities and among different utilities.

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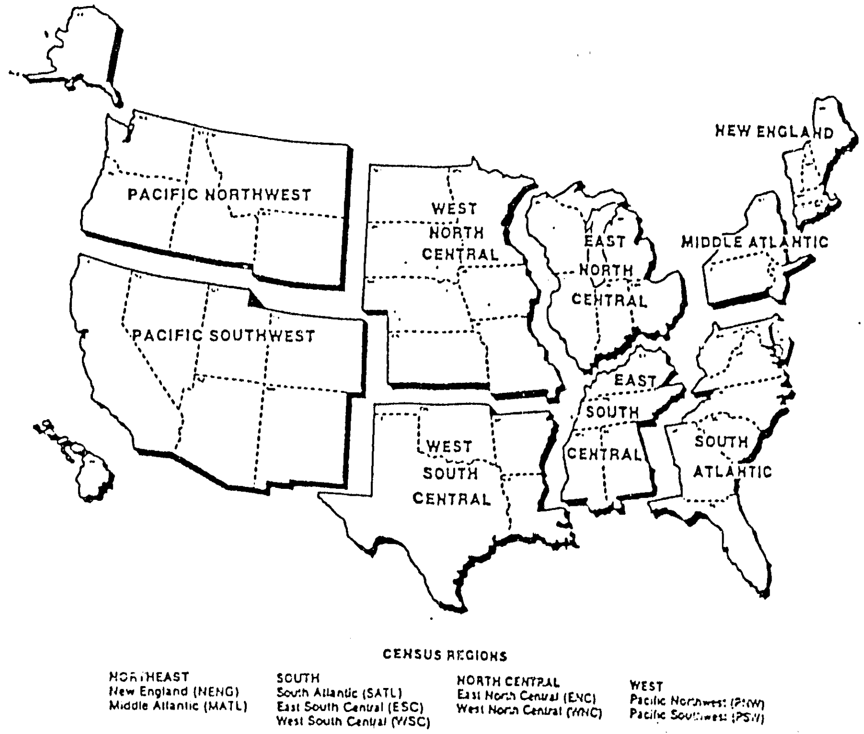

Figure 1. Regional Definitions for Emissions Estimation

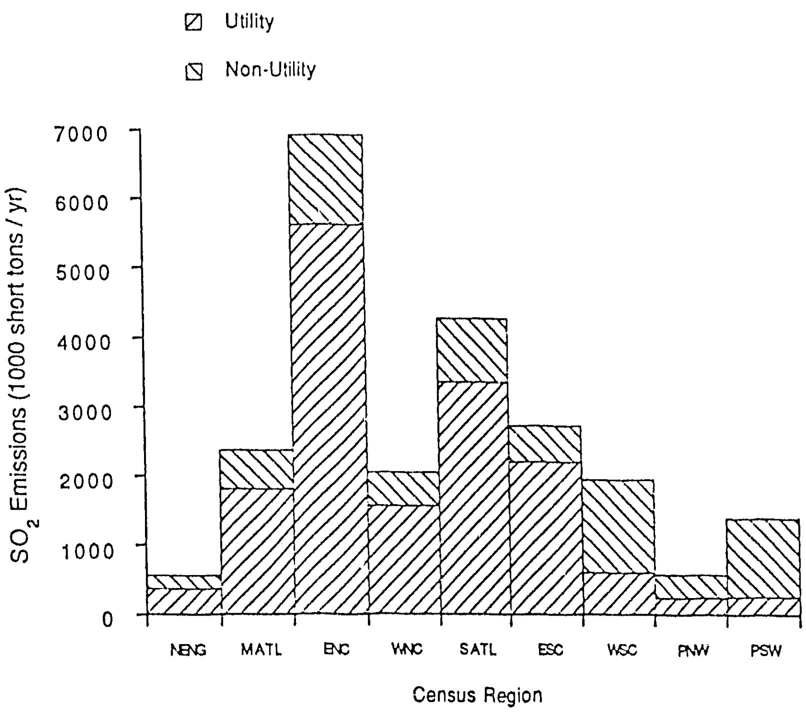

Figure 2. Distribution of SO_2 by Region From Utilities and Other Sources

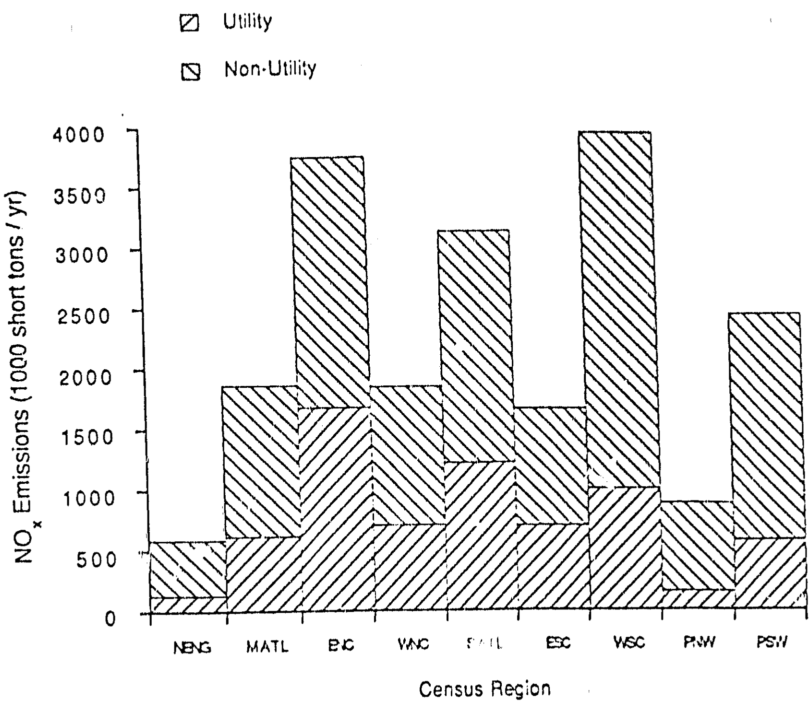

Figure 3. Distribution of NO_x by Region From Utilities and Other Sources

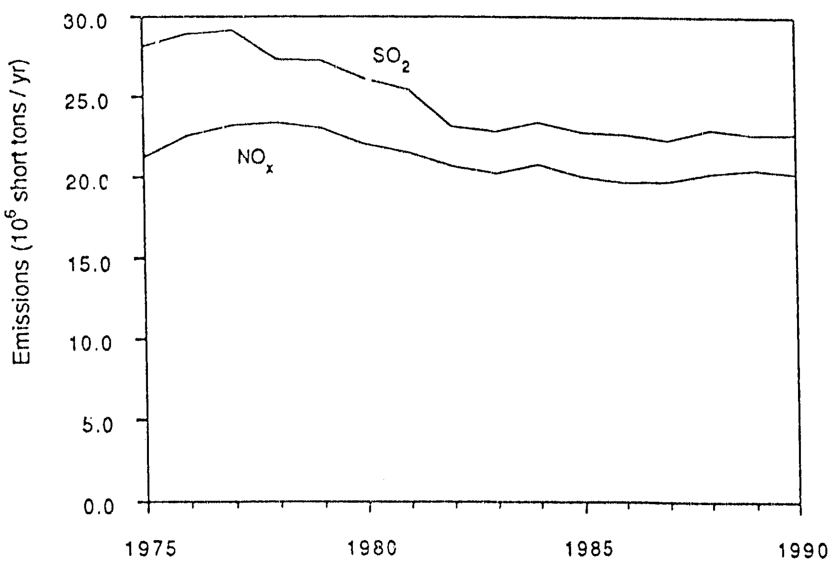

Figure 4. Trends in SO_2 and NO_x Emissions in the U.S.

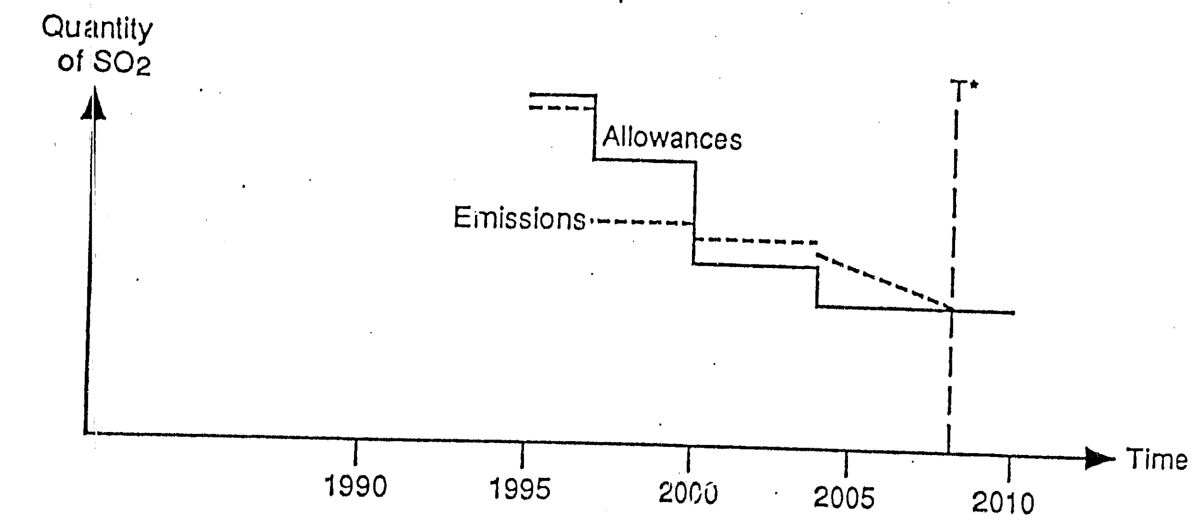

Figure 5 Allocation of Allowances Compared with the Emission Path up to Time T* at Which Banked Allowances are Used Up

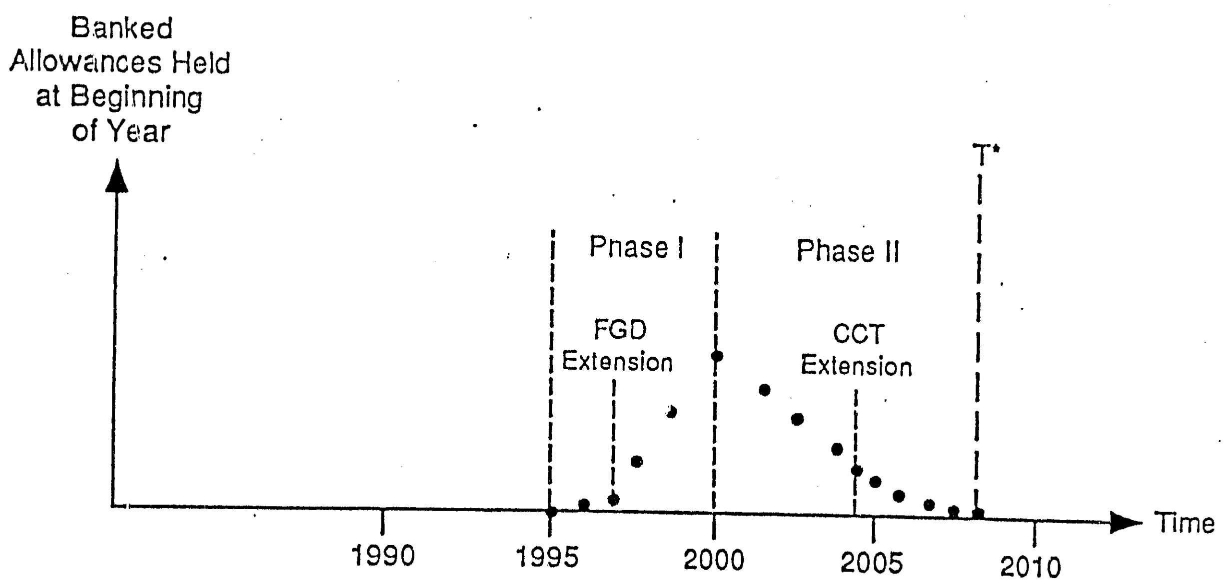

Figure 6. Accumulation and Depletion of Banked Allowances

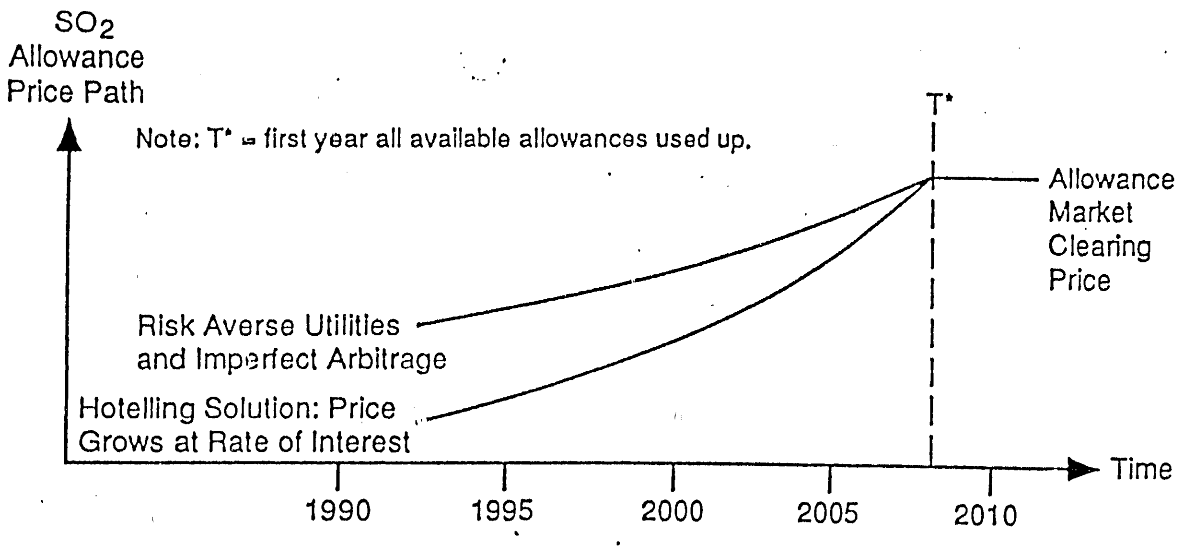

Figure 7. Anticipated Allowance Price Path With and Without Utility Risk Aversion

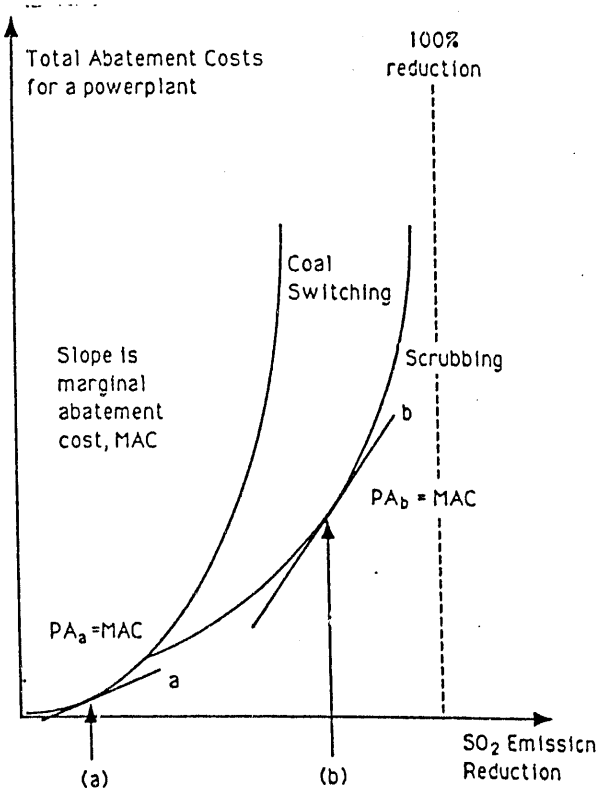

Figure 8. The Abatement Cost Frontier and Efficient Reductions

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