Market Mechanisms and Incentives: Applications to Environmental Policy

PROCEEDINGS
SESSION FOUR

SO_x/NO_x TRADES

A WORKSHOP SPONSORED BY THE US ENVIRONMENTAL PROTECTION AGENCY'S NATIONAL CENTER FOR ENVIRONMENTAL ECONOMICS AND NATIONAL CENTER FOR ENVIRONMENTAL RESEARCH

May 1-2, 2003
Wyndham Hotel
Washington, DC

Edited by Alpha-Gamma Technologies, Inc.
4700 Falls of Neuse Rd., Suite 350, Raleigh, NC 27609

ACKNOWLEDGEMENTS

Sections of this report, indicated as "summarizations", were prepared by Alpha-Gamma Technologies, Inc. with funding from the Nation Center for Environmental Economics. Alpha-Gamma wishes to thank Kelly Maguire and project officer Nicole Owens of the National Center for Environmental Economics.

DISCLAIMER

Session IV Proceedings

Table of Contents

A Comparison of the Effects of the Distribution of Emission Allowances for Sulfur Dioxide, Nitrogen Oxides and Carbon Dioxide

Dallas Burtraw and Karen Palmer

May 2, 2003

Abstract

Emissions cap and trade programs have gained wide acceptance as a cost-effective method for reducing air pollution arising from the electricity sector. One of the biggest issues in designing a cap and trade program is how to initially distribute the emission allowances. Three approaches, grandfathering to current emitters, distributing on the basis of recent generation and auctioning allowances to the highest bidder, have been proposed. The choice among these three approaches has tremendous effects on the distribution of costs and on the level of overall costs of a trading program. This paper summarizes the findings of a body of recent research on this issue and presents some new preliminary findings on how these effects can vary depending on the pollutant or mix of pollutants being regulated.

Key Words: emission trading, cap and trade, air pollution, cost-benefit analysis, electricity, sulfur dioxide, SO_2, nitrogen oxides, NO_X, carbon dioxide, CO_2, distributional effects

JEL Classification Numbers: Q25, Q4, Q28, L11, L94

A Comparison of the Effects of the Distribution of Emission Allowances for Sulfur Dioxide, Nitrogen Oxides and Carbon Dioxide

A Comparison of the Effects of the Distribution of Emission Allowances for Sulfur Dioxide, Nitrogen Oxides and Carbon Dioxide

Dallas Burtraw and Karen Palmer[Ψ]

April 28, 2003

1. Introduction

For the first time since 1990, Congress may be poised to enact major clean air legislation. Proposals now before Congress would impose dramatic reductions in emissions on electricity generators and large industrial facilities. They address multiple pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury (Hg), and some proposals address carbon dioxide (CO_2) as well. The level and timing of emission reductions dominate the political debate. But one of the most controversial issues in 1990 – the question of whether to use emission trading - has fallen off the table. All of the current proposals embrace a cap and trade program for most, if not all, of the emission reductions that would be achieved. This represents a tremendous reversal of thinking from prevailing thought just over a decade ago when trading was a controversial idea. However, in spite of its widespread acceptance as a concept, the future generation of trading programs may ultimately raise a din of controversy that outdoes earlier debates about trading.

One of the biggest issues in designing a market-based pollution policy is how to initially distribute the emission allowances. The choice has tremendous effects on the distribution of costs of a trading program. Just as importantly, how allowances are distributed can have dramatic effects on the efficiency and overall cost of a trading program, a point that is not widely appreciated.

Three basic approaches to distributing emission allowances have been proposed. Under grandfathering, the most popular approach, allowances are distributed for free to incumbent pollution-emitting firms based on generation at each plant during a base year period. Grandfathering is the main approach that has been used in cap and trade programs, including the Title IV acid rain program, to date. An alternative method of free distribution gives allowances to firms including recent entrants based on generation in a recent year or recent set of years and

[Ψ] Dallas Burtraw and Karen Palmer are senior fellows at Resources for the Future. This paper summarizes previous research under EPA STAR grant R825313 and preliminary results under EPA STAR grant R828628-01. The authors thank Larry Goulder, Ian Parry, Rob Williams, Ranjit Bharvirkar, Carolyn Fischer, David Evans, David Lankton and Anthony Paul for collaboration. Direct correspondence to Burtraw@RFF.org and Palmer@RFF.org.

allocations are updated over time. This approach, known as output-based allocation or OBA, provides firms with an incentive to increase their generation in order to increase their share of the total pool of allowances. An analogous price based approach in the form of a revenue-neutral emissions tax that refunds pollution tax revenues based on production is currently being used to reduce NO_X emissions from electricity generators and other sources in Sweden (Hoglund 2002, Sterner and Hoglund 2000). A third approach is for the government to auction the allowances to firms.

Distributional questions related to initial allowance distribution tend to be at the crux of political debates about this issue. Environmental regulations can impose large costs on regulated firms and getting allowances for free provides some compensation for bearing those costs. The fairness of a cap and trade approach from the viewpoint of electricity generators or consumers, and specifically the fairness of free distribution of emission allowances, would seem to many observers to hinge on the comparison of the value of emission allowances and the costs of emission reductions.

In general, economists overwhelmingly prefer an allowance auction to approaches that distribute allowance for free because of its generally positive implications for economic efficiency. These efficiency benefits come primarily in two forms.

First, whether electricity price is set by regulators or by the market, the value of allowances would be reflected in electricity price under an allowance auction, at least to a large degree. Using an auction prevents a potentially tremendous distortion in electricity price between regions of the country depending on the nature of regulation. Also, when electricity price reflects the full opportunity cost of emission allowances, it leads to more efficient decisions. For example, an auction provides a signal to consumers about the opportunity cost of using electricity, giving them the incentive to make investments in efficient refrigerators, etc., in a way that takes full social costs into account.

The second reason why auctions tend to be more efficient is more technical. Emission cap and trade programs raise costs in an industry just as does a new tax; in fact, these regulatory costs can be thought of as a virtual tax. Taxes have the unfortunate property of promoting inefficiency in the economy because, as a result of a tax, the willingness to pay for a good or service will necessarily differ from its opportunity cost. The size of this difference is the magnitude of the tax. A new virtual tax in the form of an environmental regulation magnifies this inefficiency, and the inefficiency grows at an accelerating rate with the magnitude of taxes in the aggregate, including the virtual tax. The virtue of an auction, in this context, is that it raises revenues that at least in principal can be used to reduce preexisting taxes.

While an auction is generally preferred on efficiency grounds, other approaches that distribute allowances for free tend to be more popular politically. One reason is that the auction will raise electricity prices at least as much as any other approach to distributing allowances. Also, when allowances are distributed for free under grandfathering or output based allocation, they endow a constituency with a valuable asset, and this constituency will speak up in favor of the given approach. The potential efficiency benefits of an auction are much more diffuse and may not benefit a specific constituency.

Within the context of the electricity sector, the relative attractiveness of different approaches to distributing allowances will vary depending on whether electricity is subject to price regulation or not. It will also vary across pollutants. In some contexts, allowance distribution could be used as a tool by states to achieve economic, fiscal or political goals. Furthermore, all these factors exert a different influence depending on the pollutant that is regulated. This is because the technologies that are affected vary by pollutant, and the technologies vary by their mix of capital and fuel costs and their place in the schedule of marginal costs for electricity generation.

This paper summarizes the research on the interaction of allocation approaches with pre-existing taxes in the context of different approaches to regulating emissions of NO_X and SO_2 from electricity generators. We avoid discussion of CO_2 in this context because the tax interaction effects of regulating CO_2 has spawned a vast literature that has been reviewed elsewhere. Then we focus on the efficiency and distributional effects of allowance distribution within the electricity sector and how these effects vary across pollutants, including CO_2, and according to how electricity prices are set.

2. The Evolution of Cap and Trade Programs for Air Pollution

The 1990 Clean Air Amendments initiated the first grand experiment in emissions trading in the regulation of SO_2 from power plants. The SO_2 program established a cap on the distribution of emission allowances each year representing about a 50% reduction in aggregate emissions. Individual firms have flexibility to decide how to comply. Firms can buy or sell allowances, or bank them for use in a future year.

Under the SO_2 program in 1990, there was a keen awareness that the allowances were valuable, but there was relatively little squabbling over their distribution. The vast majority of allowances were grandfathered to incumbent firms based on generation at each plant during a base year period.

A key difference between 1990 and today is the change in the regulation of the electricity industry. In 1990 the entire industry was subject to regulation, with prices determined by regulators and set roughly equal to average cost of providing service. Today about 17 states have committed to competitive pricing of electricity. The way that prices are set makes a huge difference in the performance of the program, and the issues are complicated. Literally billions of dollars are at stake each year in potential transfers of wealth among industry, consumers and the government.

The federal creation of emission allowances for SO_2 represented a new intangible property right with an asset value – that is, the value of allowances being given away for free – equal to roughly $2 billion per year. Under cost of service regulation, however, because firms paid nothing to acquire the allowances initially, the allowances were included in the firms' calculations of total and average cost at zero original cost. Hence, under cost of service regulation firms were prevented from charging customers for something they received for free. Firms were expected to pass along to customers through regulated prices only the cost of reducing emissions and the net cost of allowance sales or acquisitions that supplemented their free endowment.

However, under competitive pricing the relationship between price and costs is quite different. The guiding principle under competitive pricing is that electricity price is set equal to the marginal cost of providing electricity. Since the marginal cost varies significantly over the time of day and season of the year, in general marginal cost is quite different from average cost.

In competitive electricity markets allowances would be valued at their market price, or opportunity cost, without regard to how they were acquired initially. For each kilowatthour of generation, the opportunity cost of electricity would include costs such as fuel and labor costs, and in addition it would include the cost of emission allowances used to generate electricity. Firms that wake up to discover they have been endowed with emission allowances for free are not going to give them away for free. Instead, under competitive electricity pricing, firms will charge customers for using allowances at the value they would receive were the allowances instead sold in the allowance market.

However, firms may not come out ahead under competitive pricing depending on the cost of reducing emissions. Under regulated pricing, firms could expect to see their compliance cost reflected automatically in electricity price. But under competitive pricing this might not be the case. The firm might come out a loser, if its increment in revenues is less than its increment in costs. But the scenario could be reversed. Imagine a firm that operates a nuclear facility with no emissions. This facility has no costs associated with emission reductions or emission allowances, but under competitive pricing it will benefit from the increase in electricity prices due to costs borne at other facilities.

Whether or not emission allowance allocations are sufficient, or more than sufficient, to compensate firms for the cost of emission reductions is an empirical question. Whether allocations should be sufficient to do so is a political one. However, one result from economic models is clear. It is possible that the value of emission allowances could dramatically overcompensate firms for the cost of reducing emissions if all allowances are given away for free, by grandfathering, as was done under the SO_2 program.[1] Whether this is true depends on the pollutants that are regulated, especially on whether CO_2 is included, and on the portfolio of generation technologies owned by individual firms.

The second grand experiment in emission trading is the summertime NO_X cap and trade program to take effect in 19 eastern states and the District of Columbia. It will take effect for 8 northeastern states in May of 2003, and for the remaining states in June 2004.

The NO_X program is different from the SO_2 program because the distribution of emission allowances was not specified in statute or decided by the Environmental Protection Agency (EPA). Rather, the EPA established allocations to each state and those states in turn are responsible for determining the method of allocation to affected sources. Nonetheless, almost all emission allowances will be distributed for free to incumbent producers, as was done for the SO_2 program.

In times of severe budget challenges facing state governments, the value of the NO_X emission allowances has attracted the attention of some state officials, and for good reason. The annual value of the NO_X emission allowances depends on the market price of the allowances. If emission allowances trade at $2,500 per ton, the value of all the allowances will approximate $1 billion. Currently, NO_X emission allowances for use in 2005 are trading at well over twice that price, suggesting an aggregate asset value of $2 billion per year. In Kentucky, for example, the value of NO_X allowances at a price of about $5,000 per ton is over $180 million per year. In Indiana the value is around $240 million per year.

[1] In the case of the SO_2 program, Carlson et al. (2000) estimate that the annual cost of compliance with the SO_2 cap ones the program is fully implemented and the accumulated bank of allowances is drawn down to be approximately $1 billion per year, roughly half the total annual value of the allowances. As noted, the program was originally designed when electricity generators operated under cost of service based regulation, and regulators were expected to safeguard the recovery of costs. However, with the advent of competition in many states the question of the proper amount of compensation has become much more meaningful.

To return to the theme above, how these allowances are reflected in electricity price will depend on the nature of regulation in each state. In regulated regions, allowances would be reflected in electricity price at their original cost of zero, but firms would recover their cost of reducing emissions directly in electricity price, if regulators behave according to the textbook. However, in competitive regions, firms would be expected to gain from the value of allowances through higher electricity prices even if allowances are obtained for free, although they could not automatically recover the cost of emission reductions.

After the SO_2 and regional NO_X programs take effect, the next grand experiment could be the implementation of cap and trade programs being debated currently in Washington. If these programs include just SO_2, NO_X and Hg, as the Bush administration's Clear Skies Initiative would do, then the value of emission allowances may be somewhat proximate to costs. Even in this instance, however, the value could be greater than costs, especially for some firms, which is part of the reason the Clear Skies Initiative does not give all of the allowances away for free. Instead, the Initiative would institute a revenue raising auction for a small share of the allowance pie. That share starts out at 1% but ends up at 100% after about fifty years. In net present value terms, this represents about 15% of the aggregate value of allowances.

However, if CO_2 is included in the legislation, as it is in separate proposals by Senator Jeffords and by Senator Carper, the financial landscape would look entirely different. In this case it is certain that the value of emission allowances would dramatically outweigh the cost of reducing emission reductions. The primary reason is that only a small percentage of emissions will be reduced. The value of emission allowances is the allowance price multiplied by the quantity of remaining emissions. It may take a little geometry to make this point convincingly, but for a five percent reduction in emissions, the value of emission allowances could be expected to be 20 times greater than the cost of emission reductions, and probably more. Further, for CO_2, the asset value of allowances may easily exceed $30 billion per year, even under modest emission cap targets.

This poses an conundrum. What should be done with emission allowance revenues? The preference of industry is pretty clear. Grandfathering to incumbent firms has billions of dollars worth of appeal.[2] On the other hand, senators and governors may sense the appeal of this potential source of revenue to fund programs such as education, especially when it appears that grandfathering is unjustified based on costs. The Jeffords bill suggests yet another approach. The

[2] For an analysis of the effects of different allocation approaches on the asset values of firms see Burtraw et al. (2002).

bill would auction allowances, and return most of the revenue directly to households as a rebate and the federal government would not see any of it.

In public policy schools and law schools, and indeed in most economics departments, the decision about how to distribute emission allowances within a pollution trading program has been viewed as largely a distributional one. But the biggest surprise may be that this decision has tremendous efficiency implications as well. The likely outcome on this issue is not clear. It probably is clear that in the future at least some portion of emission allowances will be auctioned in one form or another, especially if society decides to use a cap and trade approach to regulate CO_2. The importance of this issue can hardly be exaggerated. Resolving this will require that policymakers address both fairness and efficiency. This body of research provides several insights that can help address the issue from both of these perspectives.

3. The Economy-wide Perspective on Efficiency

The relative efficiency of different approaches to distributing emission allowances always stems from the influence the policy has on the relationship between price and marginal cost throughout the economy. The general equilibrium literature has focused on prices in factor markets, especially the labor market, but also the capital market.[3]

The general equilibrium literature has focused on the fact that new regulations raise the costs of goods and services, and thereby lower the real wage of workers – that is, the bundle of goods and services that workers can purchase for an hour of labor. In so doing, new regulations appear similar to taxes on labor income. Both have the effect of inserting a wedge between the price of labor (the opportunity cost of a worker's time) and the value of labor to the firm (value of marginal product of labor). Hence, it is conjectured that new regulations that raise product prices potentially imposes a hidden cost on the economy by further lowering the real wage of workers. This can be viewed as a "virtual tax" magnifying the significance of previous taxes, with losses in productivity as a consequence.[4] This effect is commonly referred to in the literature as the tax interaction effect.

---

[3] Bovenberg and de Mooij, 1994; Parry, 1995; Bovenberg and Goulder, 1996. Parry, Williams, and Goulder (1998) estimate that due to pre-existing distortionary labor taxes, efforts to reduce carbon emissions through free distribution of tradable carbon permits will be efficiency-reducing unless the marginal benefits from carbon abatement exceed $18 per ton. However, the authors find an emission tax (or revenue-raising auction) can be efficiency-enhancing at any level of marginal benefits from carbon abatement if revenues are used to decrease preexisting distortionary labor taxes.

[4] A complementary issue is the effect on the measure of benefits. Williams (2002) demonstrates that the improvement in labor productivity from reducing pollution can have sizable positive effects when measured in an general equilibrium framework.

Economic instruments are likely to impose a greater cost through the tax interaction effect than prescriptive approaches because they have a greater effect on product prices, and this tends to offset some of the reduction in compliance costs. The reason economic instruments have a greater effect on product prices is that when economic instruments are used, firms must not only comply with environmental standards but also internalize the opportunity cost of the remaining emissions. In a cap and trade program, this occurs through the cost of emission allowances.

The virtue of an auction is that it raises revenues that can, in principle, be used to reduce pre-existing taxes. Two papers have examined this question in the context of conventional pollutants. One addresses SO_2 and the other NO_X.

3.1 SO_2 General Equilibrium Costs

Goulder et al. (1997) investigated the magnitude of the tax-interaction effect in the context of the SO_2 program using both analytical and numerical general equilibrium models. They find that this effect will cost the economy about $1.06 billion per year ($1995) in Phase II of the program, adding an additional 70% to their estimated compliance costs for the program. That estimate would pertain in the long run if the entire electricity sector sets prices in the market rather than bases them on cost of service. If price is based on cost of service, then the regulatory burden is much lower because allowances under Title IV were distributed at zero original cost. The hidden cost of the tax-interaction effect would be reduced substantially, but not entirely, if the government auctioned the permits and used the revenues from the auction to reduce preexisting distortionary taxes. However, under grandfathering, no revenue is available for this purpose.

If the entire industry is deregulated, the cost of the tax interaction effect could be substantial. Table 1 illustrates the relative potential cost savings from allowance trading and the hidden costs of the use of grandfathered emission allowances, compared with the costs under a command-and-control approach. The values in this table are expressed in percentage terms, normalized around the values in the first cell. This value in the first cell in the first row represents the least-cost estimate of compliance in 2010, or partial equilibrium cost, estimated by Carlson et al. (2000). The second cell in the first row represents the ratio of compliance (partial equilibrium) costs under the command-and-control scenario modeled in that study to costs under the least-cost approach, about 135% of the least-cost outcome.

The remaining rows reflect estimates of cost in a general equilibrium context. The first column summarizes the Goulder et al. (1997) finding that the general equilibrium costs of a market-based policy (emission tax or auctioned permit system) are about 129% of the partial equilibrium measure of costs in the least-cost solution. The bottom row indicates that the cost of a permit system that fails to raise revenues is about 171% of the least-cost partial equilibrium estimate.

The last cell in the bottom row of the table yields an estimate of the relative cost of command-and-control policies in a general equilibrium setting. We find that the type of policies modeled in the context of the SO_2 program, a uniform emissions standard applied to all sources, would result in general equilibrium costs that were 178% of those measured in the least-cost solution in a partial equilibrium framework.[5] In other words, the general equilibrium cost of the tradable permit program with grandfathering (171) is only slightly less than the general equilibrium cost of a command-and-control program (178). The example suggests that the failure to raise revenue and to use that revenue to offset distorting taxes may squander much of the savings in compliance costs that can be achieved by a flexible tradable permit system. As the electricity industry has moved away from cost-of-service (regulated) prices to market-based (deregulated) prices for electricity in many regions, this failure has greater relevance in the context of the SO_2 program because the opportunity cost of using grandfathered permits has a greater effect on electricity prices in deregulated regions.

3.2 NO_X General Equilibrium Costs

A similar analysis has been applied to regulation of NO_X. Goulder et al. (1999) find that the presence of distortionary taxes raises the costs of pollution abatement under all types of approaches to distributing emission allowances. This extra cost is an increasing function of the magnitude of pre-existing tax rates. For plausible values of pre-existing tax rates and other parameters, the cost increase for all policies is substantial (35 percent or more).

The impact of pre-existing taxes is particularly large for non-auctioned emissions quotas (tradable permits). Here the cost increase potentially multiple-fold. Earlier work on the design of regulatory policy emphasized the potential reduction in compliance cost achievable by converting fixed emissions standards (quotas) into tradable emissions permits. Goulder et al. indicates that the regulator's decision whether to auction or grandfather emissions rights can have equally important cost impacts. Similarly, the choice as to how to recycle revenues from

[5] The number 1.78 (178%) is the product of 1.29 times 1.35 times 1.02. The number 1.29 is the ratio of general equilibrium to partial equilibrium cost from Goulder et al. (1997) for a policy that raises revenue, such as an emissions tax. The number 1.35 is the ratio of command-and-control to efficient least-cost from Carlson et al. (2000). The number 1.02 is the ratio of general equilibrium costs for a performance standard relative to an emissions tax identified in Goulder et al. (1997).

environmentally motivated taxes can be as important to cost as the decision whether the tax takes the form of an emissions tax or fuel tax. This choice involves whether to return the revenues in lump-sum fashion or via cuts in marginal tax rates. The use of funds to reduce marginal tax rates is much more efficient, and this is particularly important when only modest emissions reductions are involved.

The difference in costs when different approaches are used to distribute allowances depends importantly on the extent of pollution abatement under consideration. Total abatement costs differ markedly at low levels of abatement, and then less so as the level of emissions is reduced. Strikingly, Goulder et al. find that for all instruments except the fuel tax these costs converge to the same value as abatement levels approach 100 percent. However, this finding appears to be the result of assumptions about the shape of the cost functions for pollution abatement. Using a detailed simulation model of the electricity sector, Banzhaf et al. (2002) find that the amount of potential tax revenues begins to decline, but then begins to increase dramatically, as the emission cap is lowered.[6] This is illustrated in Figure 2 for a range of emission targets for SO_2 and NO_X in the electricity sector.

4. Efficiency Perspective in the Electricity Market

The previous section addressed the effect on efficiency from the perspective of the entire economy. As noted already, the relative efficiency of different approaches to distributing emission allowances always stems from the influence the policy has on the relationship between price and marginal cost throughout the economy. While the general equilibrium literature has focused on prices in factor markets, in this section we discuss the effect within the product market subject to environmental regulation. The findings are again surprising and significant. The way that emission allowances are distributed can dramatically affect the cost of achieving emission reductions within a cap and trade system.

The method of distributing allowances matters to the social cost of reducing emissions within the electricity sector because the distribution of allowances can have a direct effect on the price of electricity, and more importantly, on the relationship between electricity price and marginal cost. In most time periods, in most regions of the country, electricity price differs from marginal cost leading to important deviations from economic efficiency. In this "second-best" setting, the effect of emissions trading on electricity price can modify or amplify the efficiency

[6] These simulations are done using the Haiku model. For more information about this model see Paul and Burtraw (2002).

cost stemming from the difference between price and marginal cost. A central component, therefore, is the way in which prices are determined in the electricity industry.

4.1 Institutions Setting Electricity Price

For the purpose of this discussion, let us assume the transmission and distribution parts of retail electricity price are set according to average cost and are not affected by allowance distribution. We focus attention on the cost of generation, which is more than two-thirds of electricity price and the most important part with respect to environmental policy.

How the distribution of allowances affects electricity price and the difference between price and marginal cost will depend on the institution in place for determining electricity price. The marginal cost of electricity generation varies by season and time of day. Typically, however, the price that consumers face is much less variable, meaning that generation price differs systematically from marginal cost. The method of distributing emission allowances can amplify or diminish the difference between willingness to pay (price) and marginal cost, thereby affecting economic efficiency.

In regulated regions, we assume regulators provide an incentive or otherwise require firms to utilize their facilities in a manner that minimizes the total cost of meeting the obligation to serve electricity customers at a regulated price equal to the average cost of service. Equation 1 illustrates the total annual cost of electricity generation for technology *i* as the sum of capital, fixed operation and maintenance (O&M), fuel, variable O&M and emission allowance costs. Total cost includes the opportunity cost for emission allowances associated with using technology *i* regardless of how allowances are distributed initially, as long as there is a liquid market providing the firm an opportunity to sell allowances. In this equation we suppress the change in variable costs over season and time of day and do not address the provision of reserve services, although these considerations are included in the simulation exercise.

$$T_i(q_i) = K_i + FOM_i + (F_i + VOM_i)q_i + e_i q_i p_A \tag{1}$$

where:

$$T = \text{total cost (\$/yr)},$$
$$q = \text{megawatt-hours (MWh/yr)},$$
$$K = \text{capital cost (\$/yr)},$$
$$FOM = \text{fixed O\&M (\$/yr)},$$
$$F = \text{fuel (\$/MWh)},$$
$$VOM = \text{variable O\&M (\$/MWh)},$$
$$e = \text{emission rate (tons/MWh), and}$$
$$p_A = \text{price of allowances (\$).}$$

In regulated regions electricity price depends on the firm's total cost summed over all technologies and price is set equal to the firm's average cost. Costs and consequently electricity price depend on how allowances are distributed initially, as long as the regulator follows standard practice of recognizing the original cost of acquiring allowances, rather than economic cost (market value), when determining costs that are recoverable through electricity prices. If allowances are acquired for zero cost through grandfathering or output-based allocation, then only the difference between the cost of emissions and the value of the free allocation would be a recoverable cost: $\left(\sum_i e_i q_i - D\right) p_A$, where D is the number (tons) of free allowances distributed to the firm.

Equation 2 represents how allowance costs are reflected in price in regulated regions based on how allowances are distributed. Under an auction $D=0$, and electricity price is higher than if allowances are distributed for free.

$$RP = \frac{\sum_i T_i(q_i) - Dp_A}{Q(RP)} = \frac{TC}{Q(RP)} \tag{2}$$

where:

$$RP = \text{regulated price for the firm (\$/MWh)},$$
$$Q(RP) = \text{electricity demand (MWh/yr); } Q' < 0,$$
$$TC = \text{total cost (\$/yr).}$$

We assume electricity demand equals supply, $Q = \sum_i q_i$.

In competitive regions price is set not by average cost but by marginal cost. Under perfect competition the generation component of electricity price is determined by the variable cost of the marginal facility in the wholesale power market at each moment in time. The variable cost for each technology *i,* and specifically for the marginal technology *m,* is indicated by equation 3.

Identification of the marginal technology depends on aggregate demand (Q). Again time subscripts are suppressed for convenience.

$$CP(Q) = v_m = f_m + vom_m + (e_m - s)\, p_A \qquad (3)$$

where:

CP = competitive price (\$/MWh),

v = variable cost (\$/MWh),

f = fuel (\$/MWh),

vom = variable O&M (\$/MWh), and

s = output based allocation rate (tons/MWh).

The output-based allocation rate (s) is the rate at which allowances are distributed based on generation. Incremental generation earns a share of the emissions cap equal to $1/Q$; and s equals the aggregate emission cap $(\overline{E})$ measured in tons, divided by total generation: $s = \overline{E}/Q$. Under grandfathering or an auction, the output-based allocation rate is zero $(s = 0)$. Therefore, the variable cost for each technology and consequently the price under output-based allocation is less than under grandfathering or an auction because of the output subsidy associated with the distribution of allowances.

Note also that if all technologies are eligible to receive allowances on the basis of their output, the output-based allocation is uniform for each unit of generation and it reduces the variable cost of every kWh produced by all facilities that qualify for allowances in an equal manner. Hence, the output-based allocation does not alter the relative ordering by variable cost of generation units. Also, the lower price is expected to lead to greater electricity demand. However, we will see that when different groups of generators are eligible for output based allocations, and when multiple pollutants are regulated simultaneously, then the relative ordering by variable cost of generating units can be affected.

In summary, in regulated regions the electricity price under an auction is expected to be greater than the price with grandfathering or output-based allocations, and the price with grandfathering and output-based allocation would be equal. Under perfect competition, the electricity price under output-based allocation is expected to be less than the price under an auction and grandfathering, which would be approximately equal.[7] This is summarized in by:

$$RP[au] > RP[gf] \cong RP[oba] \quad \text{and} \quad CP[au] \cong CP[gf] > CP[oba], \qquad (4)$$

[7] The relative effects of grandfathering versus an output-based approach are confirmed in Beamon et al.'s (2001) simulation analysis comparing these two approaches to allocating carbon emissions within the electricity sector.

where *au* designates an auction, *gf* designates grandfathering, and *oba* designates output-based allocation.

In practice and in our simulation exercise the equations above do not hold precisely, especially in competitive regions because most customers do not see an electricity price that is equal to variable costs on a real-time basis. Rather, they see the average of variable costs over some period of time, which means the electricity price differs from variable cost but typically not by as much as in regulated regions. Also, features of regulation such as stranded cost recovery may affect price differently under different approaches to allowance distribution. In regulated regions firms may have the opportunity to export power from unused facilities to outside the region and regulators may capture some of those profits to reduce price within the region. Also, if only certain technologies are eligible for allowances under the output-based allocation, then it will affect the cost ordering of technologies which will, in turn, lead to differences between the price under grandfathering and output-based allocation. However, the inequalities in expression (4) are expected to hold throughout.

4.2 The Magnitude of Inefficiencies in Electricity Price

The loss in economic surplus from inefficient pricing of electricity, at the margin, is measured by the difference between willingness to pay (electricity price) and marginal cost. We ignore marginal social cost, inclusive of social costs of environmental damage, and focus just on marginal private cost roughly equivalent to the cost components reported in equations 1-4.

Electricity price is expected to increase under any policy to reduce emissions due to the increase in resource costs that include changes in fuel use and capital investment required for compliance. However, as noted the magnitude of the effect differs across different methods of distributing allowances. If one policy does more to close the gap between price and marginal cost, it will do more to reduce deadweight loss and offset some of the increase in resource cost.[8]

In our simulation model in the absence of a cap and trade policy we find that price is less than marginal cost for 36% of the MWh of electricity sold for the nation, and price is greater than marginal cost for 54% of electricity sales. Even in regions with competitive pricing, we assume prices to residential and commercial customers do not reflect real-time marginal costs but rather the average of marginal costs over the season. Only 9% of electricity sales is priced

[8] See Oates and Strassman (1984) for a discussion of the role that market structure plays in determining the cost of environmental policy.

efficiently, and this occurs in regions that price electricity competitively and provide real-time pricing for industrial customers.

Even though the share of generation with price less than marginal cost is 36%, in the example illustrated in Figure 1, this negative difference has the greatest effect on economic welfare. This is because marginal cost is bounded by zero from below, so when price is greater than marginal cost the potential difference is bounded also. The upper limit on marginal cost is unbounded, so the potential difference when marginal cost is greater than price is also unbounded. Figure 1 illustrates that virtually all of the time when price is greater than marginal cost, the difference is less than $25/MWh. However, when marginal cost is greater than price the difference can be as great as $1,000/MWh.

The magnitude of the difference when price is less than marginal cost matters because the loss in welfare from inefficient pricing grows at a geometric rate with the size of the difference. This can be illustrated by considering linear aggregate inverse demand $P(Q)=w-\alpha Q$ and aggregate marginal cost $C(Q)=x+\beta Q$, where w, α, x, and $\beta>0$. Surplus is maximized where demand and marginal cost are equal at $Q*=(w-x)/(\alpha+\beta)$, that is, where price equals marginal cost. At any other quantity the deadweight loss (L) is measured by:

$$L=(w-x)(Q-Q*)-\frac{(\alpha+\beta)}{2}\left(Q^2-Q*^2\right)=\frac{-(w-x)^2}{2(\alpha+\beta)}+(w-x)Q-\frac{(\alpha+\beta)}{2}Q^2 \qquad (5)$$

The loss in welfare grows at an increasing rate as the difference between Q and $Q*$ grows. Moreover, in reality the marginal cost curve is not linear. It may be very convex in some ranges when expensive units for peak generation are brought into service, typically in ranges where marginal cost is greater than price. Thus magnitude of the welfare loss is most sensitive in ranges where marginal cost is greater than price.

Hence, the methods of distributing allowances that increase electricity price the most can therefore have the least cost in terms of loss of producer and consumer surplus from the carbon policy because these methods are most effective at closing the gap between price and marginal cost. The inequalities in expression (4) indicate that in regulated regions the auction raises electricity price the most. In competitive regions the auction and grandfathering raise prices similarly and more than the output-based approach. On the other hand, output-based allocation leads to a lower price in competitive regions because it lowers the variable costs of all generating units including the marginal generating unit and therefore it lowers electricity price. Lower electricity price also leads to greater electricity demand, thereby exacerbating the difference between price and marginal cost, and increasing the economic cost of the emissions trading policy.

4.3 Magnitude of Efficiency Effect of Allocation

The potential magnitude of the effect of different approaches to distributing emission allowances on economic efficiency in the electricity market is most dramatically illustrated by considering a cap and trade policy for CO_2 (Burtraw et al. 2002). The main finding is that allocation through the auction (labeled AU on the graph) approach is roughly one-half the cost to society of allocation through grandfathering (labeled GF on the graph) or output-based allocation (labeled OBA on the graph) when viewed over a range of emission targets. This finding is illustrated in Figure 3 in a snapshot for the year 2012. The horizontal axis indicates reductions from the baseline emissions absent any carbon policy in 2012, which are estimated to be 626 million metric tons of carbon (mtC). The vertical dotted line anchors a point equivalent to 1990 emissions in the electricity sector, which were about 150 million mtC less than in the baseline for 2012. The vertical axis reports the average social cost in 1997 dollars per mtC of emission reduction.

Average social cost is calculated as the ratio of economic cost divided by tons of emission reduction. Economic cost is measured as the sum of the changes in consumer and producer surplus in the electricity sector. We measure consumer surplus using the Marshalian demand curve and producer surplus is equivalent to producer profits. A critical issue, as we will see below, is how revenues collected under the auction are used. In the results illustrated in Figure 3, we assume revenues are redistributed to households.

For moderate emission reduction targets, the cost under the auction approach is closer to one-third the cost of grandfathering and output-based allocation, and it is somewhat greater than one-half for ambitious reduction targets. However, the comparison of social cost and cost-effectiveness of different distribution mechanisms is of growing importance under the more ambitious targets because the overall level of costs incurred and the absolute value of the cost savings under an auction grow substantially.

Figure 4 provides a partial explanation for why social cost differs among the distribution methods by illustrating the price of an emission allowance commensurate with achieving various emission reduction targets in 2012. Over the range of emission targets we examine, an auction generates the most emission reductions for a given allowance price. Although grandfathering and output-based allocation achieve comparable reductions at lower permit prices (i.e., less than $60 per mtC), grandfathering results in more reductions at higher permit prices.

4.4 Distribution of allowances can create substantial price differences between regulated and unregulated regions

The difference in methods of distribution of allowances can have a sizable effect on the difference in electricity price among regions based on the way prices are determined in each region. The relationships in expression (4) indicate that electricity prices are always expected to be highest under an auction. They are expected to be similar under different regulatory regimes but they may not be the same because under competition the technology that is at the margin will determine the degree to which costs can be passed through to consumers. For example, if the marginal technology does not have emissions, then there will be no pass through, in that time period.

The potential differences in electricity price and the interaction of regulation and the method of allocating allowances is especially evident in comparing policies for CO_2 emission reductions. This is illustrated in Figure 5, which shows the change electricity price in a scenario that includes roughly 10% emission reductions from baseline for 2012. The figure requires some caveats. A competitive baseline will have greater CO_2 emission within the simulation model, so it will require greater emission reductions to achieve a comparable emissions cap. This picture does not compare equal emissions reductions or equal emissions. Rather, the change in electricity price is normalized for the two data series indicating regulation and competition for the case of an auction. The interesting aspect is the relative change in electricity price under alternative approaches to regulation. Under competition, grandfathering affects electricity price in almost the same way as the auction, but under regulation the result is very different.

The role of output based allocation varies among regimes because under competition the subsidy to electricity generation that is implicit leads to a decline in electricity price, because that price is equivalent to variable costs inclusive of the subsidy. However, under regulation, the price is set so as to recover the full resource costs of reducing emissions and therefore it is comparable to the grandfathering approach.

The important aspect of this picture is that the choice of how to allocate emission allowances can provide as great of incentives for choosing a regulatory regime as other usual justifications in support of competition or regulation. The way in which emission allowances are allocated could conceivably be the most important factor in determination of the best approach to setting electricity prices, from the perspective of producers and consumers in a given region.

4.5 Nature of pollutant and regulation

The potential magnitude of the efficiency effect is much less for the conventional pollutants SO_2 and NO_X, but as a share of program costs they could be important. To explore this we model a policy for reduction of NO_X and SO_2. We focus on the SIP Call region. To do so we construct two pollution control regions. The SIP Call region involves a cap and trade program for both NO_X and SO_2. The long-run emission reduction target is 1.25 million tons for annual NO_X emissions and 2.1 million tons for annual SO_2 emissions in the SIP Call region. Emission allowances were distributed to NERC regions for NO_X in proportion to their share of allocations under the NO_X SIP Call. For SO_2, they were distributed in proportion to emissions in the baseline, which assumes compliance with Title IV. Outside the SIP Call region we model a separate cap and trade policy comparable to emission rates equal to Title IV. The policy is implemented in the year 2005.

To explore this scenario we redefine competition so that differences from regulation are attributable strictly to greater use of marginal cost pricing. We assume regulation and competition have equivalent rates of technological change and we assume no time of day pricing under competition. We calculate changes in economic cost is measured as the sum of the changes in consumer and producer surplus in the electricity sector. We measure consumer surplus using the Marshalian demand curve and producer surplus is equivalent to producer profits.

Our preliminary results indicate that within the conventional pollutant scenario the ordering of methods of allocations is different, from an efficiency perspective, from that under the CO_2 policy. This is illustrated in Table 2, looking across the methods of allocation under limited restructuring. The results are net present values through 2020. All results are from a current year perspective 1999, with values in 1999$. With the conventional pollutants we find the auction to be more efficient than either grandfathering or output based allocation, as was the case with CO_2. However, the ordering of grandfathering and output based differs somewhat. We find output based to be more efficient than grandfathering, although it is less efficient than an auction. Also, the difference among all the conventional pollutant policies is less, relative to the total regulatory cost, than is the case for CO_2. This is primarily because the amount of potential revenue raised under the conventional pollutant policies is less relative to the resource costs necessary for compliance.

This different result is robust across the method of regulation for the electricity industry. As in the regulation of CO_2, the auction is the least cost method across the types of regulatory regimes in the electricity industry.

As mentioned, one way that the conventional pollutant scenario differs from the analysis of CO_2 is the magnitude of revenues.[9] In relative terms, the revenues collected under an auction of CO_2 allowances always measure greater than the loss in consumer surplus and there exist revenues that can be used in principle to offset all of the consumer surplus losses and some of the producer surplus losses.

However, under the scenario we model for NO_X and SO_2, revenues under the auction are roughly 80% of the loss in consumer surplus under the auction. This results from the fact that the emission reductions targets significantly exceed fifty percent of the baseline target. Consequently we are on the portion of the total revenue curve under the auction where revenues are declining (but not to the point where revenues begin to climb again, indicated on Figure 2).

Another outcome that varies across pollutants is the effect of cap and trade programs on merit order of plants. SO_2 has the biggest effect on baseload and virtually no effect on peak since gas units do not emit SO_2, and as a result SO_2 caps are unlikely to affect electricity price as much under competition (even with an auction). NO_X caps should have a more uniformly distributed effect throughout the dispatch order since both gas units and coal units have NO_X emission rates but total costs of new NOX caps are small so price effects likely to be low. Carbon emission caps will also raise generation costs across entire dispatch order.

The third difference between the CO_2 analysis and the analysis of conventional pollutants is the focus on the SIP Call region, and the particular features about that region of the country. The region generates just under 60% of the nation's electricity. The region emits 64% of the CO_2 for the nation. In contrast, the SIP Call region is responsible for over80% of the nations emissions of SO_2 and even after implementation of the SIP Call NO_X trading program in 2004 it will emit over 50% of the NO_X for the nation's electricity sector. Consequently the focus on this region will yield results that differ from those for the nation.

Even more particular is the relationship between price and marginal cost in the region, and especially in the ECAR subregion. ECAR accounts for 31% of the nation's SO_2 emissions, and about 26% of the nation's generation. Moreover, in the relationship between price and marginal cost, Figure 6 illustrates that, given the special assumptions about competition that are maintained in this analysis, ECAR has three-quarters of its generation sold at price greater than marginal cost.

[9] An important issue is how revenues collected under the auction are used. We assume that they are available to society on a dollar-per-dollar basis, and contribute to net economic surplus.

One of the most important reasons that an auction proves cost effective in the regulation of CO_2 is that for the nation price is less than marginal cost an important portion of the time periods. The auction internalizes a price signal about the opportunity cost of CO_2 emissions and the cost of the emission reductions is somewhat offset by closing the gap between price and marginal cost. But in ECAR, the internalization of a price signal through an auction amplifies the difference between price and marginal cost by increasing price. Rather than diminishing the cost of the auction as was the case for CO_2, in the analysis of conventional pollutants the price signal amplifies the cost of the auction.

5. Distributional Perspectives

The similarity between regulated and competitive regions under an auction will depend on the degree to which changes in costs can be passed through to consumers in competitive regions. In principle, given that costs of the marginal generator determine prices, producers who own a portfolio of generation facilities may be under-compensated, or over-compensated, for their costs.

In the case of CO_2 regulation there is an opportunity to potentially dramatically over-compensate firms for the costs imposed by the regulation. Figure 7 illustrates the change in the value of generation assets under a CO_2 policy that reduces emissions by 6% from a forecast baseline for the year 2012. The effect on three representative firms are illustrated. For example, Firm B is a firm with a large coal-fired portfolio. The value of its portfolio is diminished under any of the methods to distribute allowances.

In all cases, grandfathering is the most beneficial for the firms that are illustrated. The surprising result illustrated in this figure is that for all three firms the auction is at least as beneficial as output based allocation.

This result is only somewhat different in the analysis of conventional pollutants. As indicated in Table 2, in our preliminary results we find that producers favor grandfathering by a substantial margin over other approaches to distribution. Second, producers favor output based allocation and third they prefer an auction, but the difference between these options is small. As in the case of the CO_2 policy, the reason output based allocation yields greater losses in producer surplus is that the output subsidy erodes electricity price and the value of existing generation assets.

6. Conclusion

This paper reviews several pieces of research on the efficiency and distributional aspects to distributing emission allowances in the electricity sector. We briefly discuss results from the general equilibrium literature, and then discuss in greater detail results using a detailed simulation model of the electricity sector.

An important finding is that the performance of methods to distribute allowances varies significantly based on the nature of the pollutant and the amount of reductions to be achieved. In the case of CO_2 policies, there is substantial evidence that an auction approach is the most efficient. Furthermore, in the case of CO_2 an auction generates sufficient revenue to offset entirely the loss in consumer surplus and to offset partially the reduction in producer surplus due to the policy.

In the case of the scenario constructed for analysis of conventional pollutants SO_2 and NO_X, the auction again performs best in terms of overall efficiency. However, the difference between the auction and the other policies is less dramatic than is the case for CO_2 policy. There appear to be several contributing reasons for this. Perhaps foremost is the fact that the CO_2 policy potentially generates substantially more revenue, especially relative to the resource costs of compliance, than does the conventional pollutant policy. The substantial portion of emission reductions compared to baseline put the policy on the declining portion of the total revenue curve for the auction, meaning that there are not significant revenues collected compared to the case for CO_2.

Secondly, the ECAR region, an important component of the modeling domain, exhibits a different relationship between price and marginal cost than characterizes the rest of the nation. In ECAR one finds price more significantly greater than marginal cost than elsewhere. Hence, the apparent efficiency virtue of the auction in the context of national CO_2 policy – that it internalizes in price the opportunity cost of emission reductions – becomes a liability within the ECAR region.

Another finding is the important role of the structure of electricity regulation on the efficiency and distribution effects of the pollution policy. Regulation in the electricity industry causes the auction and grandfathering to behave very differently for regulation of both CO_2 and the conventional pollutants. Depending on the package of pollutants that are regulated in the electricity industry, the way in which emission allowances are allocated could conceivably be the most important factor in determination of the best approach to regulation of the electricity sector, at least from the perspective of producers and consumers in a given region.

References

Banzhaf, Spencer, Dallas Burtraw, and Karen Palmer. 2002. "Efficient Emission Fees in the U.S. Electricity Sector". RFF Discussion Paper 02-45 (October).

Beamon, J. Alan, Tom Leckey, and Laura Martin. 2001. "Power Plant Emission Reductions Using a Generation Performance Standard," Energy Information Administration, (Draft: 3/19/2001).

Bovenberg, A. Lans and Ruud A. de Mooij. 1994. "Environmental Levies and Distortionary Taxation." *American Economic Review* 84:1085-9.

Bovenberg, A. Lans and Lawrence H. Goulder. 1996. "Optimal Environmental Taxation in the Presence of Other Taxes: General Equilibrium Analyses." *American Economic Review* 86:985-1000.

Burtraw, Dallas, Karen Palmer, Ranjit Bharvirkar and Anthony Paul. 2001. "The Effect of Allowance Allocation on the Cost of Carbon Emission Trading," Resources for the Future Discussion Paper 01-30 (August).

Burtraw, Dallas, Karen Palmer, Ranjit Bharvirkar and Anthony Paul. 2002. "The Effect on Asset Values of the Allocation of Carbon Dioxide Emission Allowances," *The Electricity Journal* vol. 15, no. 5, 51-62.

Carlson, Curtis, Dallas Burtraw, Maureen Cropper, and Karen Palmer. 2000. "SO_2 Control by Electric Utilities: What Are the Gains from Trade?" *Journal of Political Economy* 108(6): 1292–326.

Goulder, Lawrence H., Ian W. H. Parry, Roberton C. Williams III and Dallas Burtraw. 1999. "The Cost-Effectiveness of Alternative Instruments For Environmental Protection in a Second-Best Setting," *Journal of Public Economics,* vol. 72, no. 3 (June), 329-360.

Goulder, Lawrence H., Ian W. H. Parry and Dallas Burtraw. 1997. "Revenue-Raising vs. Other Approaches to Environmental Protection: The Critical Significance of Pre-Existing Tax Distortions," RAND Journal of Economics, vol. 28, no. 4, (Winter), 708-731.

Hoglund, Lena. 2000. "Essays on Environmental Regulation with Applications to Sweden," Ph.D. Dissertation, University of Goteborg.

Oates, Wallace E. and D.L. Strassmann. 1984. "Effluent Fees and Market Structure." *Journal of Public Economics* 24(June): 29–46.

Parry, Ian W. H.. 1995. "Pollution Taxes and Revenue Recycling." *Journal of Environmental Economics and Management* 29:S64-77.

Parry, Ian W.H., Roberton C. Williams and Lawrence H. Goulder. 1998. "When Can Carbon Abatement Policies Increase Welfare? The Fundamental Role of Distorted Factor Markets." *Journal of Environmental Economics and Management*.

Paul, Anthony and Dallas Burtraw. 2002. *The RFF Haiku Electricity Market Model*, Washington, DC: Resources for the Future (June).

Sterner, Thomas, and Lena Hoglund. 2000. "Output-Based Refunding of Emission Payments: Theory, Distribution of Costs, and International Experience," Resources for the Future Discussion Paper 00-29 (June).

Williams, Roberton C. III. 2002. Environmental Tax Interactions When Pollution Affects Health or Productivity. *Journal of Environmental Economics and Management* 44: 261–70.

Table 1. General Equilibrium Cost of SO_2 Allowance Trading as Percentage of Partial Equilibrium Least-Cost Compliance

Percentage values normalized around first cell	*Least-cost compliance (%)*	*Command-and-control performance standard (%)*
Partial equilibrium measure	100	135
General equilibrium measure		
with revenue	129	*n/a*
without revenue	171 (Title IV)	178

Table 2. Net present value of the change in economic surplus in the SIP Call region, from current year perspective of 1999, with analysis through 2020. (billion 1999 $)

	Au	**GF**	**OBA emitters**	**OBA all except hydro and nuclear**
Consumer Surplus	-43.8	-27.4	-10.9	-11.6
Producer Surplus	-22.3	-7.0	-20.4	-21.1
Sum	*-66.1*	*-34.4*	*-31.3*	*-32.7*
Revenue to Government	35.6	0	0	0
Net Direct Surplus	*-30.5*	*-34.4*	*-31.3*	*-32.7*

Figure 1. Cumulative distribution of electricity sales (MWh) according to the difference between price and marginal cost (P-MC)

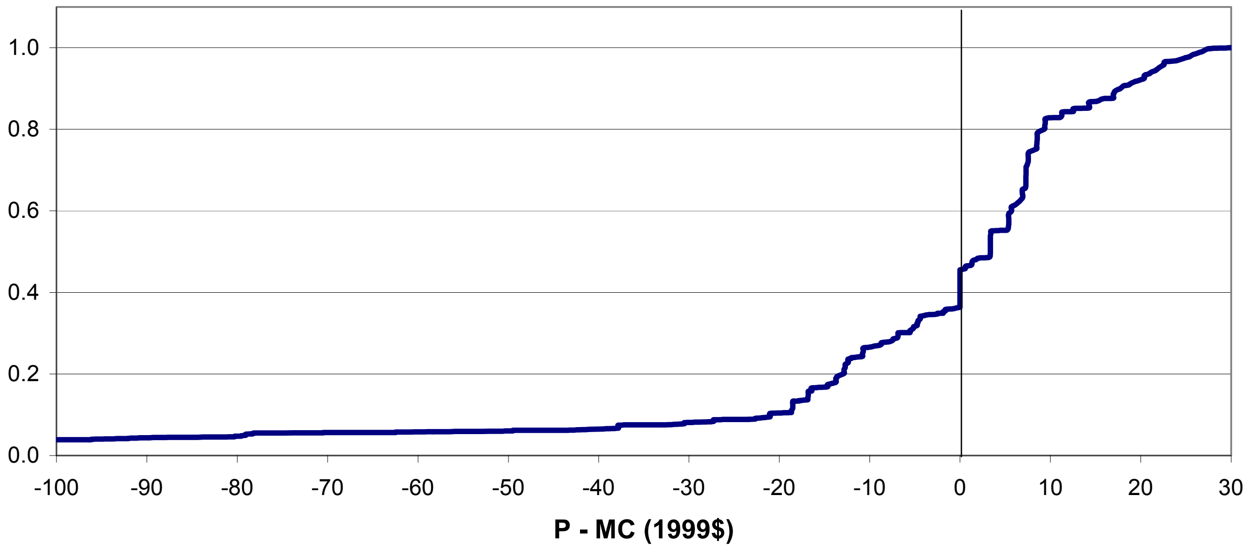
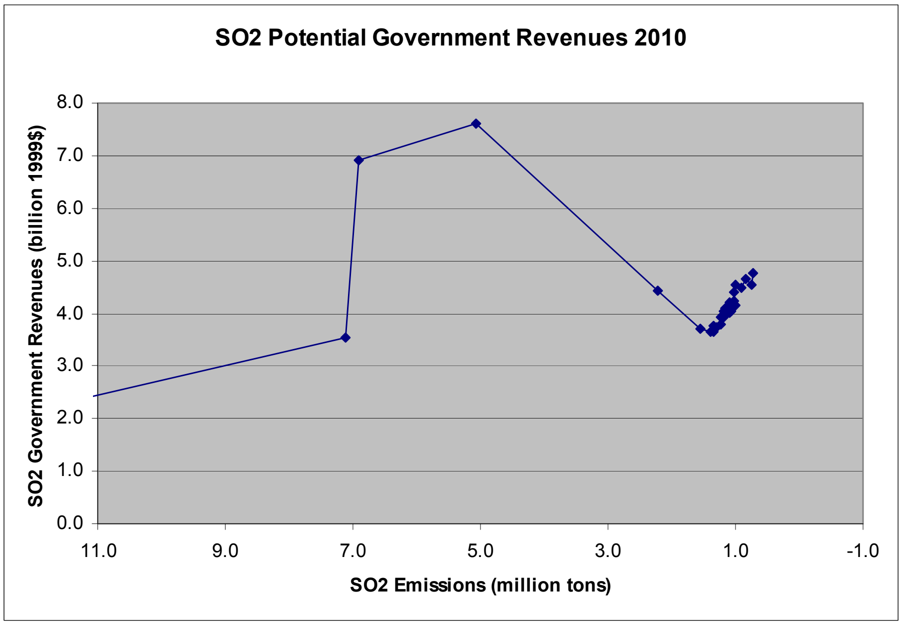


Figure 2. Potential Government Revenues from Auctioning SO2 and NOX Allowances as a Function of the Respective Emissions Caps



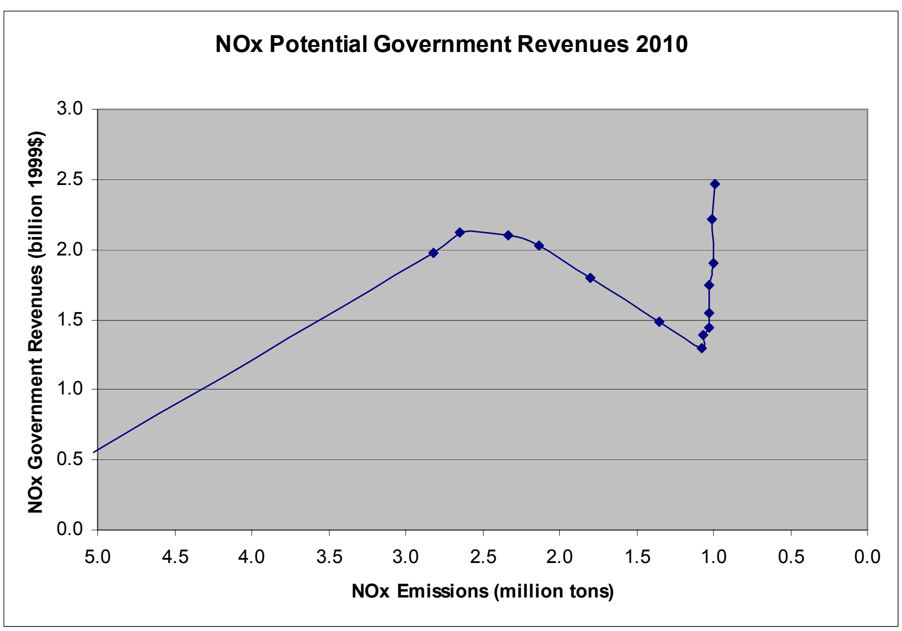


Figure 3. Social cost of allocation approaches over a range of emission targets.

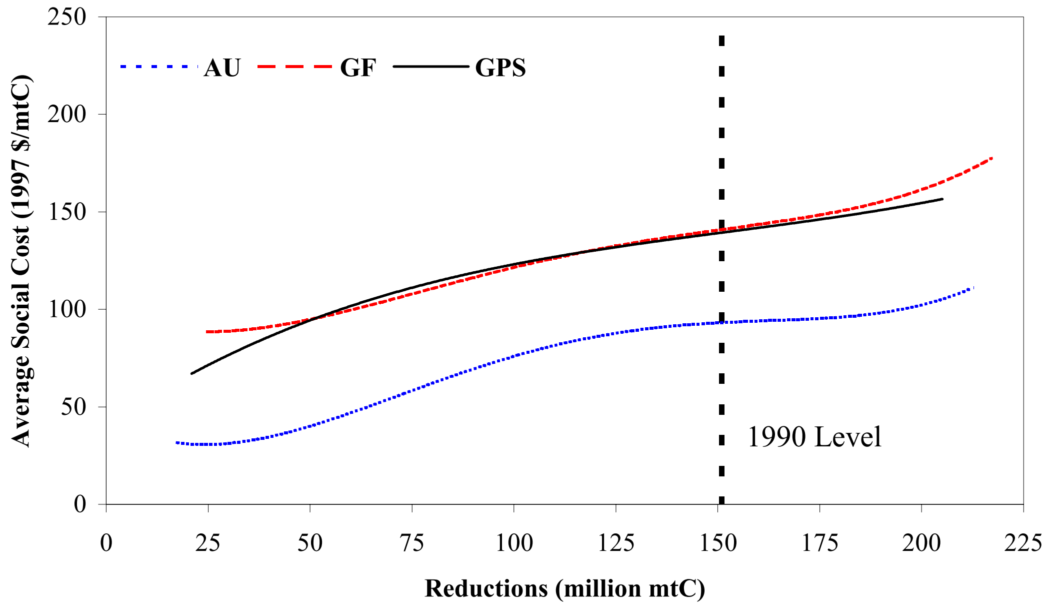


Figure 4. Allowance price for different allocation approaches over a range of emission targets.

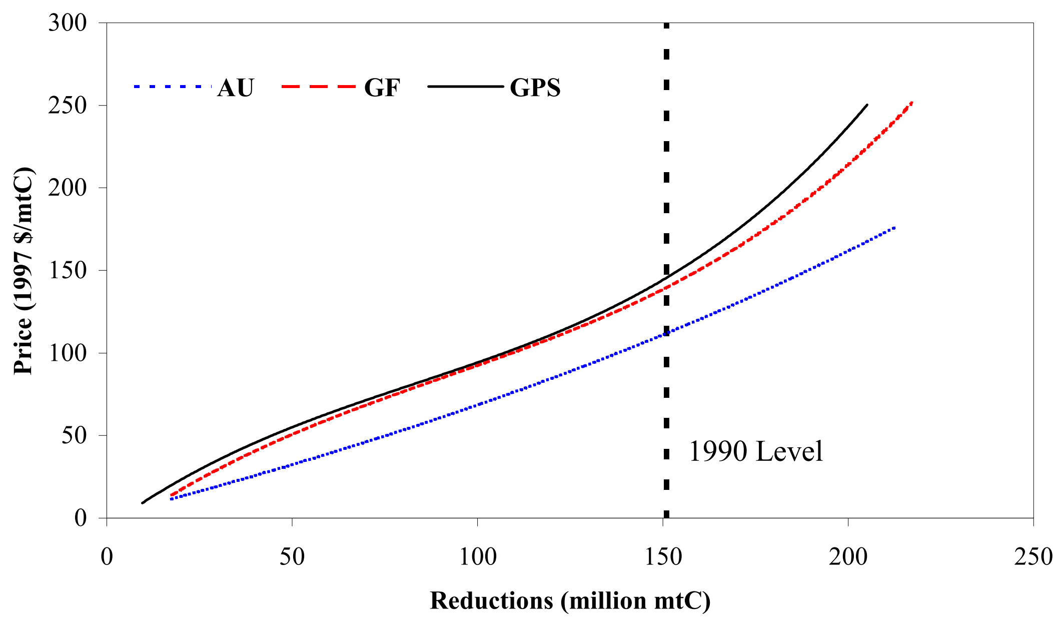


Figure 5: Percent Change in Electricity Price for Carbon Emission Reductions under Different Approaches to Electricity Regulation

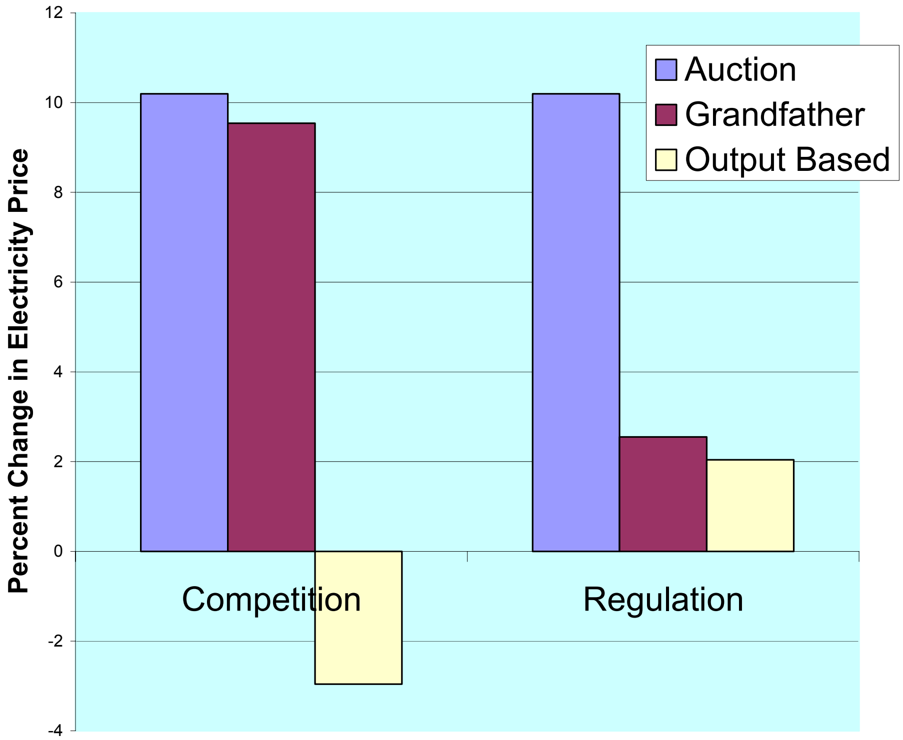
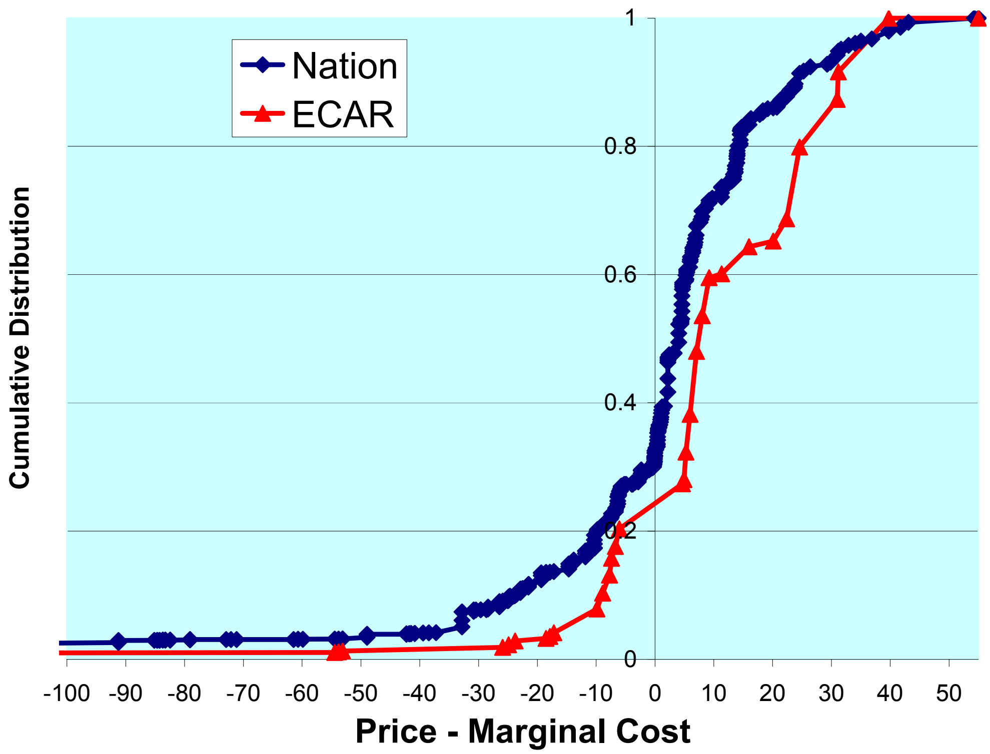
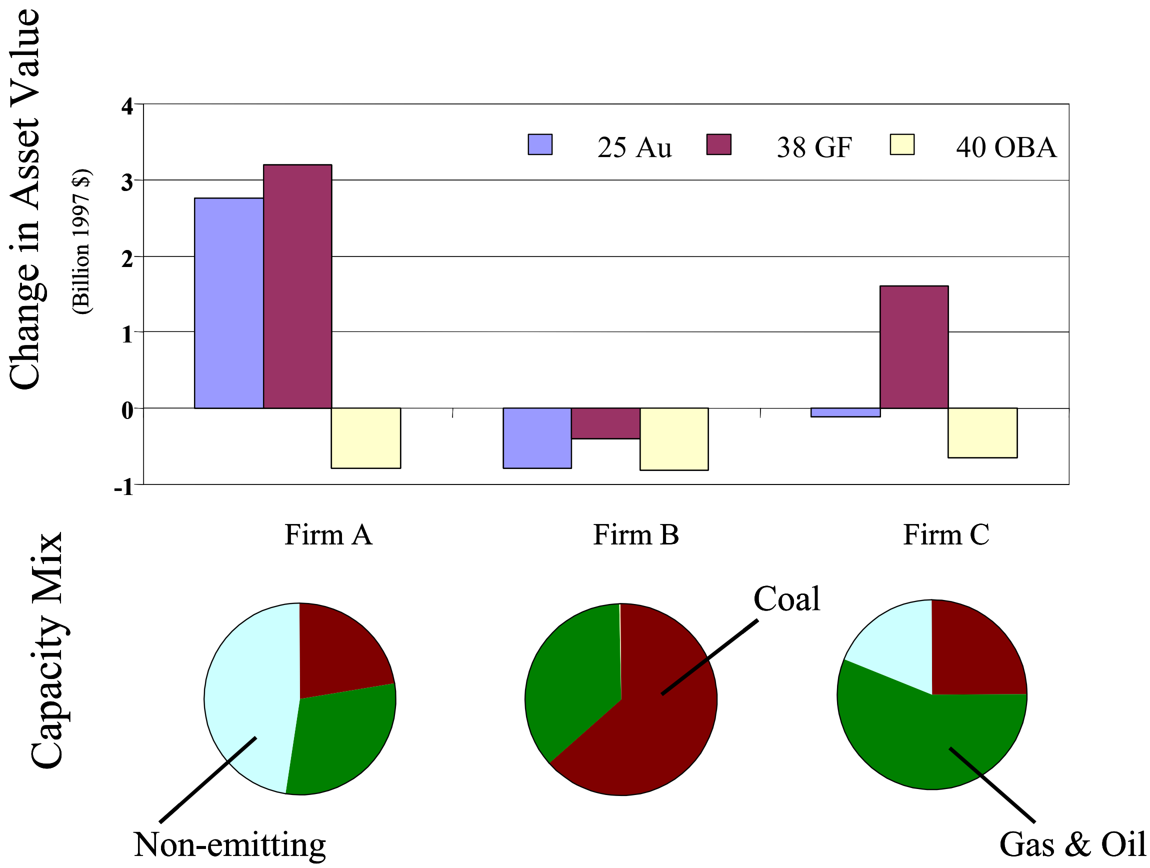


Figure 6: For Conventional Pollutant Scenario, Cumulative Distribution of Electricity Consumption Measured by Difference between Price and Marginal Cost for the Nation



and for ECAR.

Figure 7: The Change in Value of Generation Assets under a Carbon Policy, and the Effect on Three Representative Firms



Efficiency and Distributional Consequences of the Allocation of Emission Allowances in the Electricity Sector

Dallas Burtraw and Karen Palmer

Resources for the Future

"Market Mechanisms in Environmental Policy"
EPA / National Center for Environmental Research
May 2, 2003

Cap and trade approaches have gained wide acceptance because of demonstrated cost-effectiveness.

One of the biggest issues in designing a program is how to initially distribute allowances.

Distribution affects fairness and has unanticipated and large effects on efficiency.

Three Allocation Schemes

- (Au) Auction
- (GF) Grandfathering
- (OBA) Output Based Allocation (updating)

When Does Allocation Matter to Efficiency?

…When prices of goods and services differ from opportunity costs.

The allocation can amplify or diminish these distortions away from economic efficiency.

Why Does Allocation Matter?

1. Interactions with factor markets in the general economy.
(so-called "Tax-Interaction Effect")
2. Inefficient pricing in the product market that is the subject of environmental regulation.

General Equilibrium Perspective

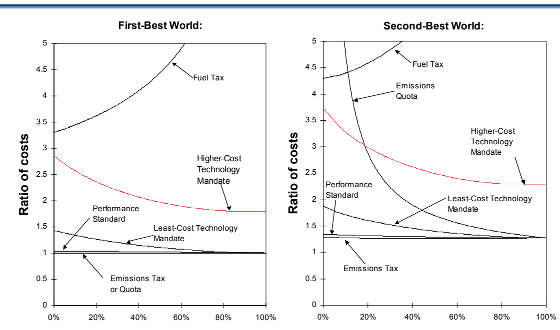
- Models assume perfect competition, constant returns to scale.
- Internally consistent linkages between all factor markets.
- Two articles examined SO_2 and NO_x. Both found substantial costs from grandfathered permits relative to other policy approaches.

SO_2 General Equilibrium Costs

Percentage values normalized around first cell	**Least Cost Compliance (%)**	**Command and Control Performance Standard (%)**
Partial Eqm Measure	100	135
General Eqm Measure		
• with revenue	129	*n/a*
• w/o revenue	171 (Title IV)	178

Table draws on Goulder, Parry and Burtraw, 1998, *Rand Journal* and Carlson, Burtraw, Cropper and Palmer, 1998, *J.Pol.Econ.*

NO_X General Equilibrium Costs: Ratio of policy to first-best emissions tax



Citation: Goulder, Parry, Williams and Burtraw, 1999, *J. Public Econ.*.

Electricity Sector Perspective

Different from CGE approach, because…

- Heterogeneous technologies represented with non-constant returns to scale, long-lived capital
- Able to capture important institutions
- Price not necessarily equal to MC
- Comparable to NEMS or IPM approach

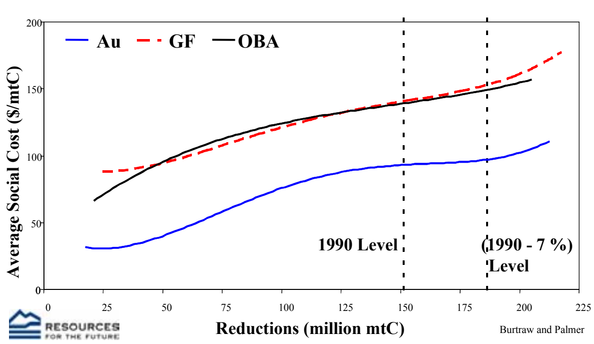
Results for Carbon Appear to Reinforce CGE Findings

➢ Allocation through an Auction is roughly one-half the cost to society of Grandfathering or OBA.

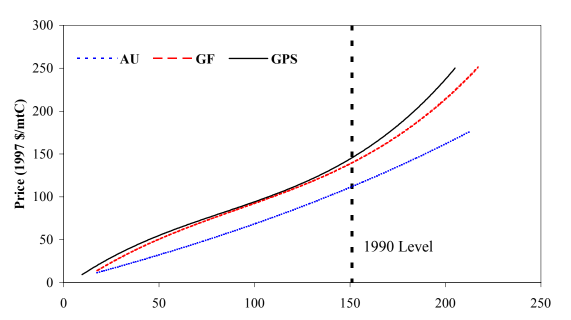
Also…

- Auction preserves **asset values** better than OBA.
- However, Auction raises **prices** to consumers.

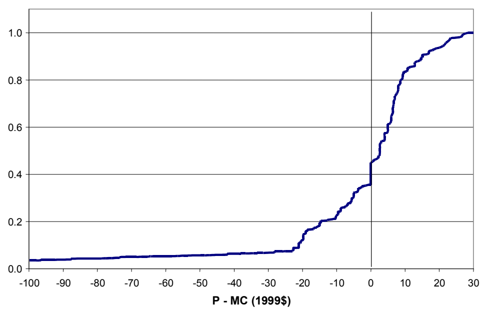
Social Cost Within Electricity Sector Varies Importantly with Choice of Policy



Carbon Permit Price Varies According to Choice of Policy



Inefficiency from $P \neq MC$



Determining Electricity Price

Regulated Price = Average Cost = (Total Cost ÷ Production)

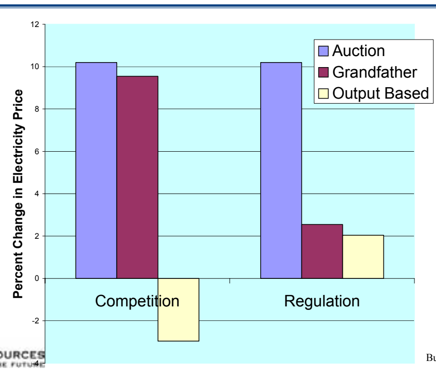
=> Price [Au] > Price [GF, OBA]

Competitive Price = Variable Cost of Marginal Unit

=> Price [Au, GF] > Price [OBA]

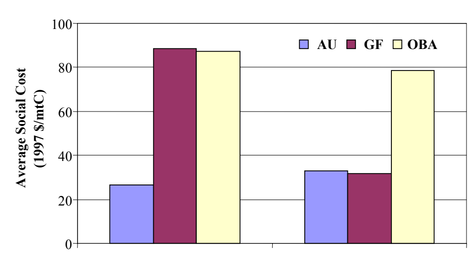
Price Effects Vary by Interaction of Regional Electricity Regulation and Choice of Carbon Policy

(2012, normalized to change under competition)



Social Cost under Limited & Nationwide Restructuring

(1997 $ in 2012; required carbon reductions vary to achieve same target)

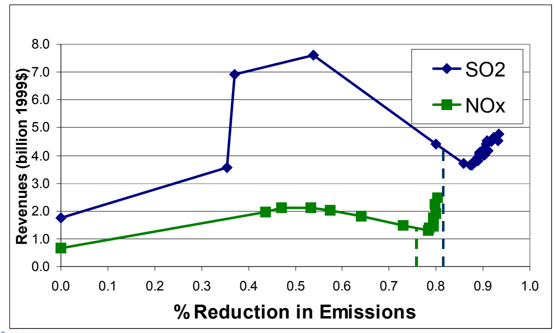


Three Reasons Why SO_2/NO_x May Behave Differently

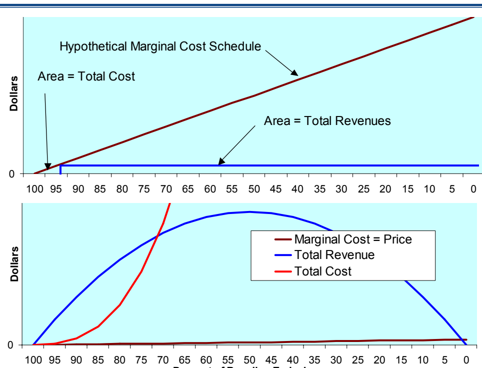
1. Declining revenues from additional emission reductions
2. Regional differences in "price – marginal cost"
3. Different technology

=> How important is each feature?

1. Emission Targets Are On the Declining Portion of the Total Revenue Function

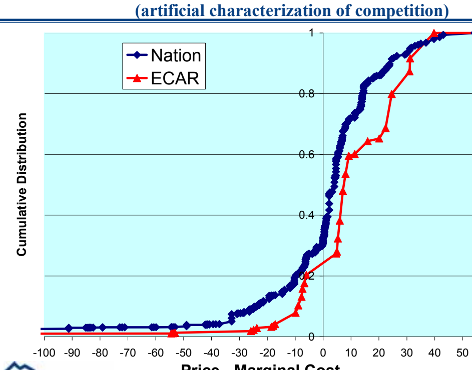


Likely Targets for Carbon Are On Increasing Part of Revenue Schedule

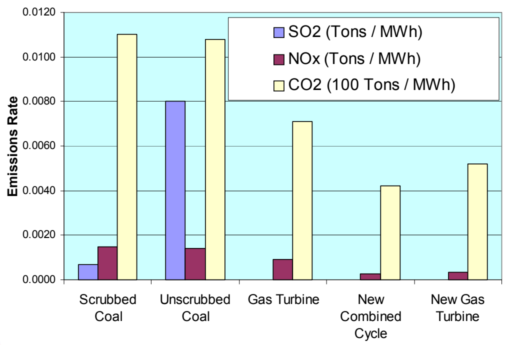


2. Price Differs from Marginal Cost Depending on Regulation, Technology

(artificial characterization of competition)



3. Effect on Price Varies with Technology of Marginal Generator

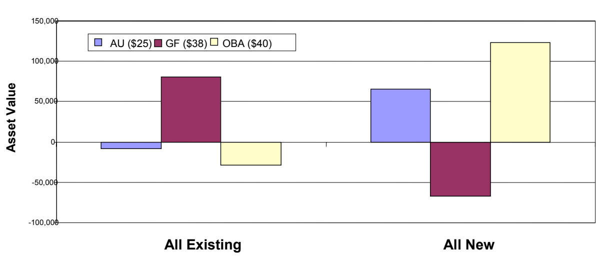


Distributional Perspectives

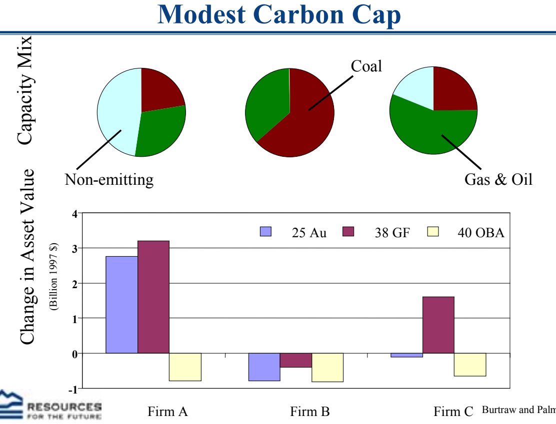
- To varying degrees, the free allocation of permits can potentially over-compensate firms at the expense of consumers.
- The effect on firms varies with their technology portfolio, and with regulation of prices.

Change in Asset Values and Compensation Under Moderate Carbon Policy

(1997 \$/MW in 2001; 35 million mtc carbon)



Illustrative Effects on Three Firms of Modest Carbon Cap



Conclusion

- Society's cost of emission cap programs can vary dramatically with method of distributing allowances.
- For carbon, an auction is dramatically more efficient. Output-based allocation undermines asset values and harms many firms.
- Free allocation (grandfathering) of carbon permits also can dramatically over-compensate firms.
- The story may be different for conventional pollutants; output based allocation may be less inefficient.
- The effects on firms and consumers may vary widely based on electricity regulation and technology portfolio.

Temporal Hotspots in Emission Trading Programs:

Evidence From The Ozone Transport Commission's NO_X Budget

Alexander E. Farrell*
Energy and Resources Group
University of California, Berkeley
afarrell@socrates.berkeley.edu

Presented at a conference on:
Market Mechanisms and Incentives:
Applications to Environmental Policy

May 1-2, 2003
Washington, DC 20005

Sponsored by
US EPA National Center for Environmental Economics (NCEE)
US EPA National Center for Environmental Research (NCER)

* This research was supported by the EPA's Science To Achieve Results (STAR) program. The author would like to thank the many industry and government people who spent time discussing this analysis, and Antonio R. Paez, who provided valuable research assistance. All opinions and any remaining errors are those of the author alone.

Introduction

The use of Market Mechanisms and Incentives (MM&I) for environmental protection has increased over the last several years, and proposals for new MM&I policies are increasing. Notable (perhaps even principal) among these proposals are cap-and-trade (C/T) systems, which as the name implies, create a permanent limit on total emissions yet provide firms with flexibility in compliance. Several concerns have been raised about the environmental and economic outcomes of C/T systems, in particular about the potential for "hot spots" and about the viability of markets in emission allowances. Environmentalists are concerned that C/T systems may allow for localized pollution problems while industry is concerned that there be a large, stable enough market in allowances so that they can count on being able to buy or sell allowances at reasonable and predictable prices (Dudek and Goffman 1992; Solomon and Rose 1992; Campbell and Holmes 1993; Chinn 1999). The results so far have been mixed on both counts, some emission trading programs have had problems with hot spots and environmental justice issues and others have not (Drury 1999; Swift 2001). Similarly, some emission allowance markets have been successful and others have not (Foster and Hahn 1995; Carlson *et al.* 2000; Israels *et al.* 2002).

This paper examines several key aspects of an early multi-state C/T system designed to control oxides of nitrogen (NO_X) in nine Northeastern States, the Ozone Transport Commission's (OTC) NO_X Budget. Several earlier papers have examined the political economy of the OTC NO_X Budget (Farrell 2001; Farrell and Morgan 2003). Electricity generating plants, including co-generators, dominate regulated facilities in the OTC NO_X Budget (representing more than 90% of seasonal NO_X emissions) and will have a key role in the upcoming NO_X SIP Call, so this paper focuses on the electric power sector (U.S. Environmental Protection Agency 1998).

The OTC NO_X Budget is a cap-and-trade (C/T) system[1] operated jointly by the nine states shown in green in Figure 1: CT, DE, MD, MA, NH, NJ, NY, PA, RI, plus the District of Columbia. Three states in the OTC chose not to participate in the NO_X Budget Program (ME, VA, VT), shown in yellow. Maryland did not participate in 1999 due to a lawsuit. The NO_x Budget applies to electrical generating units 25 megawatts or larger and similar-sized industrial facilities (such as process boilers and refineries), and covers a 5-month control period from May through September. The NO_x budget has uses a C/T system to reduce emissions by 55-65 percent for 1999–2002 and 65-75 percent starting in 2003.

The OTC NO_x Budget has some important and distinctive features. First, there were no early auctions or other methods for price discovery before the year it actually went into effect, and no method to build up a bank of allowances before the start of the program. These have proved important in other markets (Ellerman *et al.* 2000 pp. 161-5, 174-6). Second, the NO_X Budget is operative only during the 'ozone season' of May through June. Third, and most unusually, banked allowances can be discounted through provisions called 'progressive flow control' (PFC). Under these rules, several months after the true-up date for the relevant control period, regulators determine the discount factor for all banked allowances for the upcoming year. Although a relatively straightforward formula is used to determine the discount factor, it is based

[1] This paper assumes the reader has a general familiarity with MM&I policies. For a more detailed description of emission trading programs, see Farrell, A. E. (2003). Clean Air Markets. In Encyclopedia of Energy. C. Clevelenad, Ed.: Academic Press. pp. forthcoming..

on aggregate behavior of all firms that hold allowances, so individual firms do not know what (if any) discount will be applied to their allowances until after they have made decisions about banking allowances. This adds an element of uncertainty to the allowance market.

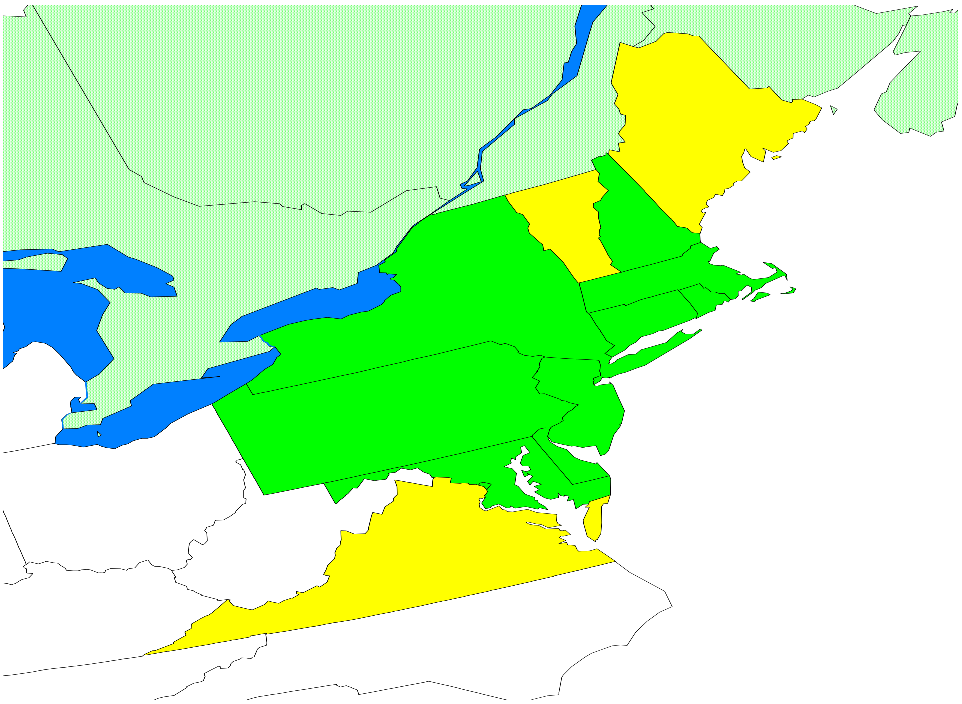


Figure 1: Sates in the Ozone Transport Region.
Green: States in the OTC NO_X Budget Program.
Yellow: States not the NO_X Budget Program

The intent of PFC is to deal with the episodic nature of photochemical smog (commonly measured in terms of ozone concentrations) in the northeastern United States (Possiel and Cox 1993). Smog is a secondary pollutant, formed from precursor compounds, of which NO_X is the most important in the OTC region (Milford *et al.* 1994). Unhealthful smog levels occur in the OTC region on only a limited number of days (usually <20 per year), which occur when meteorological conditions are most favorable for smog formation and accumulation. These are typically hot summer days when anthropogenic NO_X emissions also tend to rise as electric power plants increase generation to meet air conditioning demand. PFC was implemented to limit the use of banked allowances out of concern that if one or two cool summers was followed by a hot summer, firms would build up a significant number of allowances that could allow them to emit more NO_X than the capped level, possibly allowing firms to comply with the requirements of the program without achieving its goals.

However, it is not clear that progressive flow control adequately addresses this problem of a mismatch between the time period of the environmental problem (2-5 day episodes) and the control period (5 months). Even small differences may be important because ozone concentrations are highly non-linear functions of local NO_X concentrations. This is potential problem may be exacerbated by the fact that power plant operation and several NO_X control technologies can be easily adjusted in near real-time and because restructuring has led to higher power prices when demand is greatest (Zhou *et al.* 2001; Blumsack *et al.* 2002).

NO_X control technologies can be divided into three rough categories: combustion controls, selective catalytic reduction (SCR) and non-selective catalytic reduction (SNCR). Combustion controls (e.g. low-NO_X burners, overfire air, etc.) are used to change the shape, temperature profile and air/fuel ratio of the flames in the boiler in order to minimize the amount of fuel and atmospheric nitrogen (NO_2) that is oxidized. The other two technologies are used to chemically reduce NO_X into molecular nitrogen (N_2) and water (H_2O) by spraying a nitrogen-based chemical reagent, usually urea (CH_4N_2O) or ammonia (NH_3) into the flue gas.

In the case of SNCR, reagent is introduced close to the boiler because the greatest NO_X reduction is achieved at temperatures between1, 600-2,200°F. Multiple injection locations may be required to permit adequate control during partial load conditions. Typical SNCR technologies can lower NO_X emissions 30-50% from coal-fired power plants, although more recent advances may give better performance. The capital costs for SNCR units are about 10-20$/kW for retrofits and half that for new construction, the difference being the need to modify boilers and flues in during a retrofit. Operating costs associated with reagent, maintenance and power requirements usually amount to 1-2$/MWh.

SCR controls are very similar, except that they contain beds of catalyst, usually made of a vanadium/titanium formulation (V_2O_5 stabilized in a TiO_2 base) and zeolite materials. The flue gas flows around and through these catalyst beds, speeding up the reduction reactions and allowing for much lower temperatures, 650-720°F. SCR technologies can lower NO_X emissions 70-95% from coal-fired power plants. The capital costs for SCR units are about 50-150$/kW for retrofits and less for new construction, although very unit-specific difficulties in fitting an SCR unit into (or next to, or on top of) an existing power plant can drive those costs up. Operating costs associated with reagent, catalyst cost, maintenance and power requirements usually amount to 4-8$/kWh, largely dependent on the catalyst's life.

Two important potential are problems associated with SCR and SNCR controls. The first is the buildup of ammonium bisulfate on the pre-heater or other downstream components. These buildups can reduce plant efficiency and may require maintenance to remove them. The second problem is that ammonia may contaminate the fly ash, which may make it difficult or unsafe to handle and thus hard to sell to concrete makers or other buyers. Thus, careful, controlled operation of these technologies is required to maximize plant operation and revenue.

Under these conditions, power plant operators may respond to economic incentives in the both the production of electric power and the management of NO_X emissions, possibly turning NO_X controls down when electricity prices are highest in order to increase electricity production (and therefore revenue), or possibly shifting from one plant to another as fuel prices change, thus changing the rate and mass of NO_X emissions during hot summer days. Such actions could lead to higher levels of air pollution than would be expected under a command-and-control approach, and raises the question of whether the periodicity of the NO_X Budget gives firms too much temporal flexibility even with progressive flow control (Farrell *et al.* 1999).

Concern about spatial hotspots is more common than about temporal hotspots. Here the question is: Does emission trading result in a geographic pattern of emissions that is undesirable, even if total mass emissions are limited by a cap? This concern is sometimes associated with the term 'wrong-way trades', suggesting that an emission trade may in effect move pollution from a relatively clean area to a relatively dirtier area. This concern also forms the basis of environmental justice claims of disparate impacts on minority communities.

Concerns about these temporal and spatial effects have been an important part of the policy landscape. For instance, the RECLAIM program had two trading zones as well as a policy that did not allow banking from one year to another, features that addressed each of these issues (Fromm and Hansjurgens 1996). Some local emission reduction credit programs feature sunset provisions for credits. The debate about the Clean Air Act's Acid Rain Program for SO_2 featured a spatial limitation almost to the end and the current Clear Skies Initiative features spatial limitations (Nash and Revesz 2001 pp. 589-593; Bush 2002). Some experts feel this is an inherent problem of C/T systems and several solutions have been proposed, including trading zones, markets in units of environmental degradation or health impacts, offset ratios in emissions markets, and a web-based analysis for quick pre-approval of proposed emission trades (Atkinson and Tietenberg 1987; Raufer 1998; Nash and Revesz 2001). Others who have looked at such restrictions are skeptical (Bernstein *et al.* 1994; Stavins 1997).

Several studies on the potential existence and importance of hot spots have been conducted. Some simulation-based analyses so far of the Acid Rain SO_2 program have shown benefits from trading (Burtraw and Mansur 1999). Simulations of NO_X emission trading systems in the eastern part of the United States and in California showed no significant effect due to directionality (i.e. no significant net 'wrong way' trades and no significant hot spots), but that limiting trading to avoid even the potential problems imposed a cost increase for a C/T system of several percent (Johnson and Pekelney 1996; Dorris *et al.* 1999). Several simulations by Nobel and others of NO_X C/T system in the Houston-Galveston area have shown that spatial and temporal variability can produce only small changes in outcomes, compared to the average benefit, and that these changes may be slight improvements (Nobel *et al.* 2001; Nobel *et al.* 2002). However, these studies have all been simulations of one sort or another. One of the goals of this paper is to examine data based on the actual outcomes of a C/T system to gain insights into the potential for hot spots to be a problem in practice.

The overall effects of the NO_X Budget Program are described in the Environmental Protection Agency's (EPA) annual compliance reports for the OTC NO_X Budget program, which provide aggregate results, including the number of units regulated, ozone season emissions and allowance allocations (by state and total), the number of banked allowances (total), noncompliance issues and the progressive flow control ratios.[2] This analysis goes somewhat deeper by examining data at a much more fine level of temporal detail (hourly).

Data and Methods

Qualitative data used in this study was gathered from interviews with participants in the NO_X Budget Program, including regulators, managers in regulated firms, and brokers. Electric power plant and other plant configuration information were compiled from several sources, including EPA's *E-GRID* database, several EIA reports and publicly available material provided by firms with facilities regulated by the NO_X Budget. Unit-specific, hourly NO_X emissions data for all sources in the OTC NO_X Budget for 1998-2001 were obtained from Resource Data International (RDI). Weekly NO_X allowance prices were obtained from several brokers and industry trade publications, especially *Air Daily*, for 1998-2003. Hourly electricity data (demand, generation,

2 http://www.epa.gov/airmarkets/cmprpt/index.html

imports, and prices) were obtained from the Independent System Operators (ISO) for the New England (NE), New York (NY), and Pennsylvania-New Jersey-Maryland (PJM) interconnects. Fuel prices were obtained from RDI and the New York Mercantile Exchange.[3]

Insights from the interviews and literature review were used to guide the several quantitative analyses that followed. There are 907 'sources' in the OTC NO_X Budget Program, which, in 2000 had emissions of 952,049,548 lbs. This study focused on 'large' (>100MW_e) electric power plants and co-generators, which accounted for 773,530,680 emissions in 2000, or 81% of all regulated emissions. This data set contained 476 units combined in 137 plants. A part of this analysis considered only power plants and not co-generators and part considered only plants in PJM, due to data availability. Data from 1998-2000 was used. Table 1 shows some of the details of large power plants in the OTC states and post-combustion NO_X controls.

Table 1: Large (>100MW) power plants (not co-generators) in the OTC States

	Number of Units	Capacity (MW)	Post-Combustion NO_X Controls (2002)	
			SCR	SNCR
CT	26	3767	1	2
DC	2	550	-	-
DE	13	2149	--	1
MA	27	6891	3	1
MD	48	8386	2	1
NH	9	1034	2	-
NJ	67	8157	2	2
NY	153	16519	4	-
PA	64	15962	3	-
RI	6	1127	4	-
Total	415	64542	21	7

The first quantitative analysis compared key values in terms of emissions and emissions rates for various periods. Because power plant emissions are closely associated with generation, comparisons to control for the effect of changes in demand were made. In addition, because emissions during ozone periods are of greatest importance in terms of human health, these periods were identified and compared as well. The second quantitative analysis consisted of a series of Ordinary Least Squares (OLS) regressions designed to more rigorously investigate possible reasons for observed changes in NO_X emissions during the course of the year. Again, greatest focus was given to the periods during which NO_X emissions have the greatest potential impact on human health – ozone episodes.

[3] Relevant URLs include: http://www.epa.gov/airmarkets/egrid/, http://www.eia.doe.gov/fuelelectric.html, http://www.emissions.org/, http://www.energyargus.com/, http://www.epa.gov/airmarkets/tracking, http://www.iso-ne.com/, http://www.nyiso.com/, and http://www.pjm.com/

Results

The interviews with the participants in the OTC NO_X Budget Program indicated a wide variety of opinion. The early years of this market (1997-2000) occurred in a very different world – this was while the dot.com stock market bubble and electricity industry restructuring were underway, and before the financial scandals associated with Enron and some electric power markets. A key finding of this study was that virtually every firm with a requirement to reduce emissions took a conservative approach to the trading of emissions allowances. They traded relatively infrequently and generally did not rely on the market very much for compliance.

Reluctance to rely on the NO_X Allowance market came from several sources. Perhaps most importantly, market participants perceived very large uncertainties in the market, especially over the ability to purchase allowances. The relatively small number of potential participants in the NO_X market and, over time, the observation that relatively few transactions occurred during most weeks, meant both buyers and sellers were concerned that their own participation in the market could change market prices, generally in an unfavorable direction. The slow pace of the allowance market may have been enhanced by a somewhat hurried start of the program in 1999 and the lack of mechanisms for early price discovery, such as allowance auctions (Farrell 2000). Uncertainties were also introduced by the PFC provisions, and lawsuits (especially in Maryland) in 1998-99.

Another reason for reluctance to rely on the market was that most firms thought of the NO_X Budget program as a regulatory issue for which the most appropriate concept is compliance, rather than a market opportunity for which the most appropriate concept would be profitability. The relatively low cost of the program relative to electricity markets at the time may also have contributed. For instance, using average values for the 2000 ozone season, NO_X emission allowances were priced at 0.40$/MWh, while electricity prices averaged 42$/MWh and peaked at over 1,500$/MW in at least one market. Given these incentives, it is likely that power plant operators would focus on reliability in generating electricity over making slight changes to the emissions control equipment to optimize NO_X control costs. The structure of contracts in electricity markets would tend to reinforce this effect, since they punish both over- and under-generation relative to the amount promised in day-ahead markets. Interviews with market participants and power plant operators supported these arguments. Thus, many firms with regulated sources participated in the NO_X market only occasionally, whenever their total environmental compliance plan was modified, which might happen only once or twice per year.

An exception to this observation of low participation can be found in speculators in the NO_X Allowance Market, including Enron, Arizona Power System, and individual trading desks at some regulated firms. Speculative activities were not uncommon in the first few years of the market but became more rare after 2001, as many markets slowed down.

The results of the first set of quantitative analyses are discussed next. Table 2 shows a variety of emissions values as well as generation for the ozone seasons (May-September) in 1998-2001. This information is shown in graphical form in Figure 2. The data has been normalized in the tables to allow all the relevant values to be shown on the same figure. Total emissions over the NO_X season (tons) declines in each year, and declines substantially (by almost 25%) in the first year of the program from the pervious year. Similarly, the average emission rate (lb/hr) declines every year. However, the peak emission rate recorded over any single hour during the ozone season at first declines by about 15% from 1998 to 1999 and then rises again, although never rising higher than pre-program levels. The peak emission rate may be a better indicator of the impact of the OTC NO_X Budget program than the seasonal values because of the episodic nature of the ozone problem. This suggests that there may be a problem with temporal hotspots. However, it should be noted that even the 1998 emissions were lower than the baseline used for the OTC NO_X Budget program, which was 1990. In addition, it is hard to know what the counter-factual condition would be (i.e. if there was no NO_X Budget, what regulatory program would exist?) and what the resulting emissions profile would be.

Table 2: Ozone Season NO_X emissions and generation

Year	Emissions (tons)	Avg. NO_X rate (lb./hr)	Peak NO_X rate (lb./hr)	Avg. NO_X rate (lb./MWh)	Peak NO_X rate (lb./MWh)	Generation (GWh)
1998	156,484	83,310	134,947	2.9	20.0	108,799
1999	120,048	63,082	115,628	2.1	8.2	118,107
2000	117,025	60,640	124,125	1.2	5.5	134,390
2001	111,043	57,223	126,556	1.1	3.0	131,521

Note: These data are for all power plants, including those in Maryland that only participated in the 2000 and 2001 NO_X Budget program.

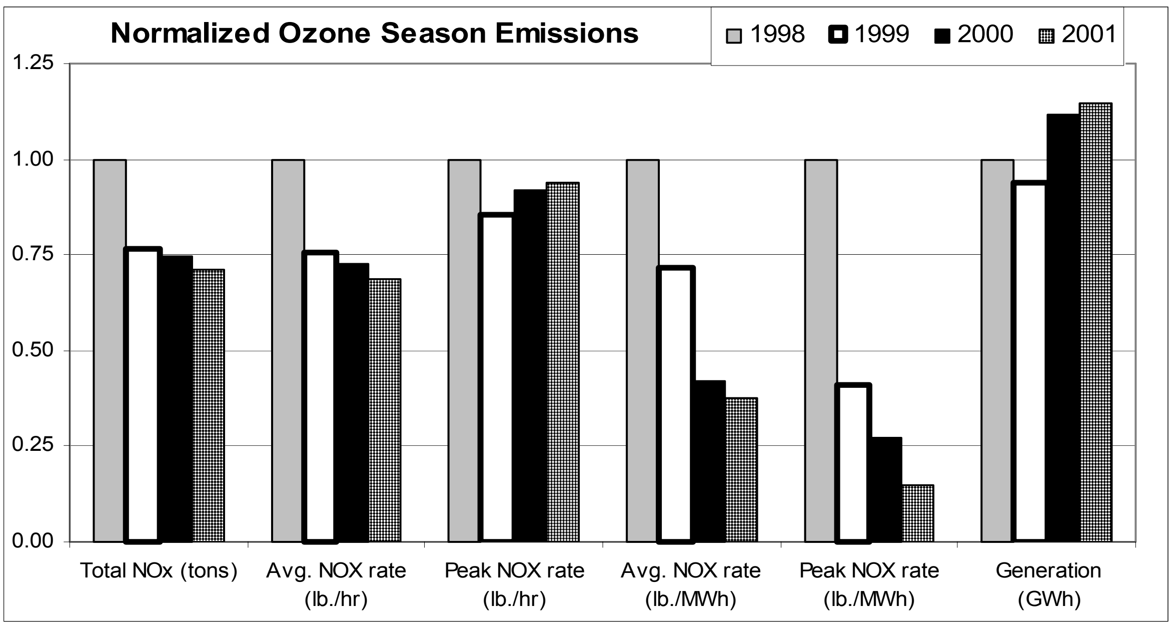


Figure 2: Normalized Emissions during the ozone season

Also significant are the very substantial declines in emissions per unit of output (lb./MWh, or emission factor), which is a result of both declining emissions and rising generation. This analysis shows that the large (>100MW) power plants in the OTC NO_X Budget controlled emissions, on aggregate, more each of the first three years of the program. Similar but less strong trends are seen in annual emissions data (not shown here).

Table 3 and Figure 3 present emissions and generation for the worst ozone episode in each year, as measured in New York City (which is roughly in the center of the OTC states). Peak ozone concentrations ranged from 0.142-0.171 parts per million (ppm), compared to the health standard of 0.120ppm. Two episodes lasted three days (2000 and 2001), and two lasted four days (1998 and 1999), making the total tons and total generation results less easily comparable.

Table 3: Ozone episode NO_X emissions and generation

Year	Emissions (tons)	Avg. NO_X rate (lb./hr)	Peak NO_X rate (lb./hr)	Avg. NO_X rate (lb./MWh)	Peak NO_X rate (lb./MWh)	Generation (GWh)
1998	5,670	91,996	121,570	3.0	4.9	3,374
1999	4,238	85,038	110,573	2.8	5.5	2,980
2000	2,483	65,658	83,643	1.2	1.7	2,135
2001	3,801	100,976	126,556	1.8	3.0	3,177

Notes: These data are for the worst ozone episode in each year, which were of different lengths.

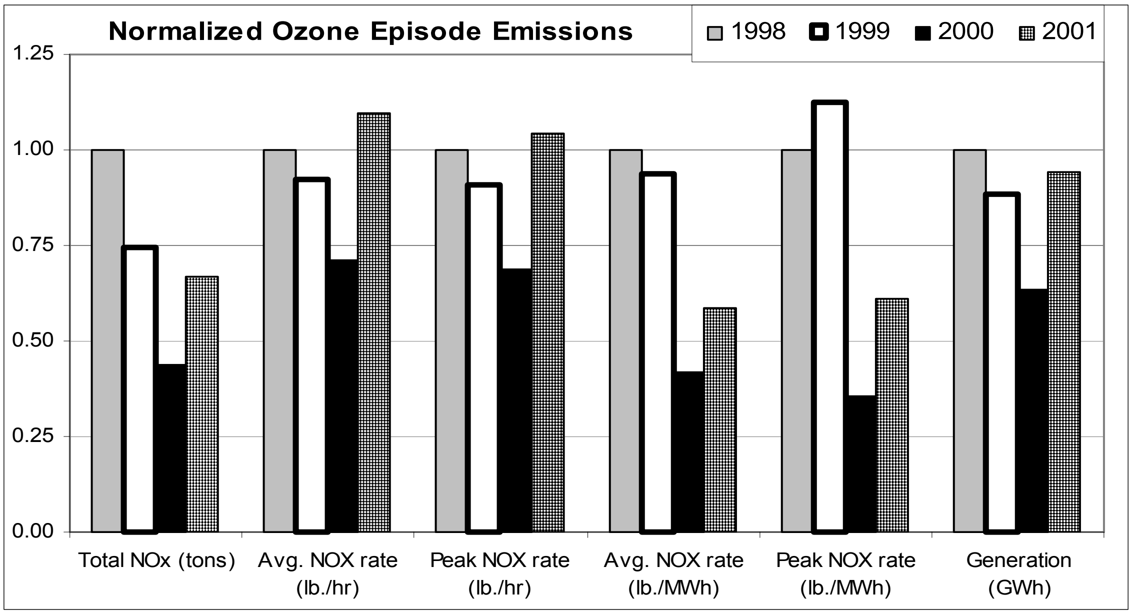


Figure 3: Emissions and generation for the worst ozone episodes in four years

As with the ozone season analysis, total emissions during ozone episodes periods decreased with the NO_X Budget, but they have not declined each year since 1998. However, the average and peak NO_X emission rates (lb/hr) are highest in 2001, while the peak emission factor (lb/MWh) is highest in 1998. More tellingly, average generation (in MW, not shown) during these episodes is considerably (12%-80%) higher than during the ozone season as a whole. Further, comparing between Tables 1 and 2, it can be seen that the absolute magnitudes of the average NO_X emission rates (lb/hr) are substantially (8% to 77%) higher during the ozone episodes than during the entire ozone season they occur in. Thus, temporal hotspots do occur under the OTC NO_X Budget program, however it is not yet clear if this is due to the C/T system.

One reason for the high emission rate in 2001 is that electricity demand for this period (8/7-8/9) was extremely high. Total generation for these three days was greater than that for the four-day long ozone episode of 1998 (3.18GWh compared to 2.98 GWh), while peak generation was even more exceptional (52GW compared to 37-39GW for the other three episodes). At the same time, the 2001 ozone episode was the least severe, with a peak concentration of 0.142ppm.

This analysis suggests two things. First, NO_X emissions under a C/T system are strongly correlated with electricity generation. This is particularly important because the same is true of traditional command-and-control regulation, the most reasonable counter-factual regulatory situation. Second power plant NO_X emissions in the Northeast are not always determinative of the level of smog problems in the area. This may be important because it suggests that even if there is a temporal hotspot problem for all seasonal NO_X C/T trade systems designed to combat regional photochemical smog, relatively modest-sized hotspots may not matter.

While an increase in emission rates due to increased electricity demand (and thus increased generation) would occur under both C/T and traditional command-and-control regulation, it may still be the case that plants take advantage of the temporal flexibility and change their operations during ozone episodes or other periods (such as when electric power prices are higher. Aggregate comparisons here are difficult in particular because to a significant degree, NO_X emissions depend on which specific power generators are operating at any give time. One approach would be to look at periods with similar total power generation, when the units operating would be roughly similar.

This approach is taken with Table 4 and Figure 4, which present data for four three-day periods with generation close to the three-day period containing the worst ozone episode in 2000 (00e). The first two are also taken from 2000, one period during the ozone season (00s) and one period is not during the ozone season (00n). The second two are from the ozone seasons in 1999 and 2001 (99 and 01, respectively). While not a perfect control, this should reduce the differences due to having different generators running for any given period, assuming dispatch order does not change appreciably.

Table 4: Emissions and generation for periods comparable to a 2000 ozone episode

Period	Emissions (tons)	Avg. NO_X rate (lb./hr)	Peak NO_X rate (lb./hr)	Avg. NO_X rate (lb./MWh)	Peak NO_X rate (lb./MWh)	Generation (GWh)
00e	2,483	65,658	83,643	1.2	1.7	2,135
00s	2,236	59,217	87,471	1.2	1.4	1,916
00n	3,613	95,527	113,253	2.6	3.6	2,315
99s	2,766	74,117	101,968	2.6	3.2	1,880
01s	2,008	52,917	82,768	1.1	1.6	1,820

Note: Table contains data for four three-day periods with total generation close to the worst ozone episode in 2000, 6/9-6/11, labeled 00e. Period 00s occurred during the 2000 ozone season. Period 00n occurred during 2000 but not during the ozone season. Period 99s and 01s occurred during the 1999 and 2001 ozone seasons.

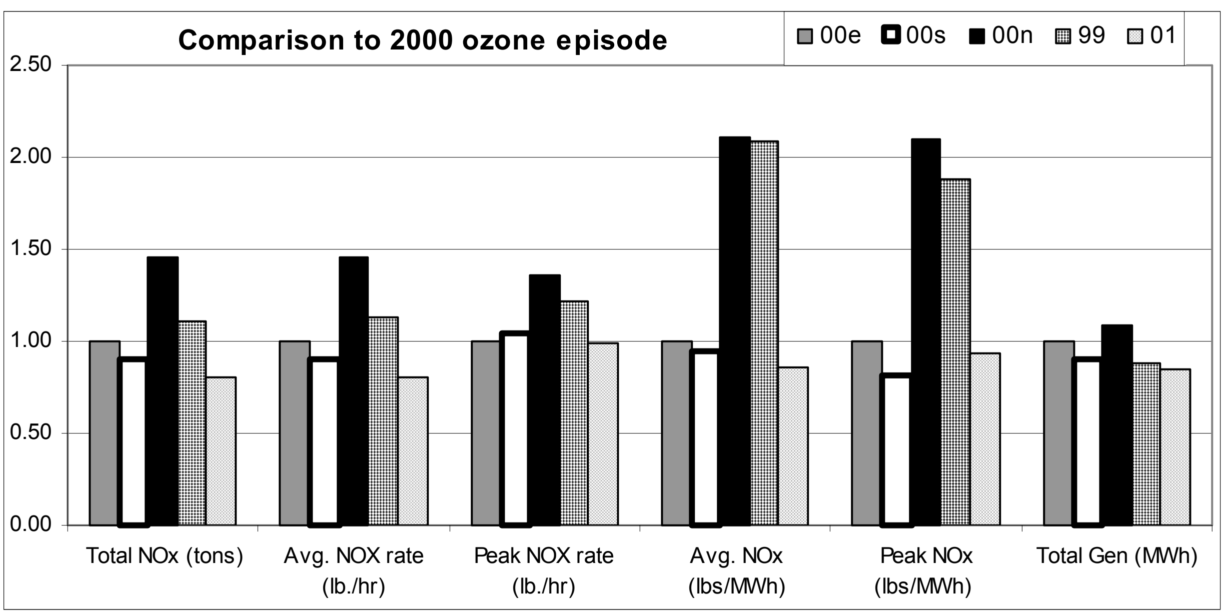


Figure 4: Emissions and generation for periods comparable to a 2000 ozone episode

Emissions in the non-ozone season comparison period (00n) are substantially higher than those, during the season, which is expected. Differences in terms of the emission factor (lb/MWh) are greatest, which is important because this metric reflects changes in dispatch and plant operation and is independent of amount of electricity generated. The emissions of the other two comparison periods (00s and 01s) suggest, on the contrary, very similar dispatch and plant operation. This suggests that the NO_X Budget Program does not tend to change the propensity for temporal hotspots. To test this definitely, however, a more rigorous approach is needed.

A set of OLS regression models were developed to test for the effect of the OTC NO_X Budget program on temporal hotspots by looking for evidence of changes in the behavior of large (>100MW) power plants. Data for 2000 was used. This analysis proceeded in three steps.

First, several models were estimated using data for all the large plants in the OTC region. The second step consisted of using the same models with data from large plants in PJM and specifying additional models were specified with variables for electricity prices, which were available for the entire year only for PJM. Power plants in the PJM interconnect account for a majority of electricity capacity in the entire OTC region (55%), so these results are reasonably representative of the overall outcomes.

The results from the first two steps are presented in Tables 5 and 6 below. The models are specified to use generation, fuel prices, electricity prices, and the OTC NO_X Budget to explain hourly ozone emissions. Various specifications were used; those shown here demonstrate the results best. All of the coefficients are significant at the 0.001 level, and all have the expected sign, save two minor exceptions.

Model 1 consists only of a variable for electricity generation at power plants (excluding co-generators for the OTC data) and a constant. Even this simple model achieves high explanatory power (R^2 values of 0.64 for the OTC and 0.78 for PJM). This confirms the earlier assumption that electricity generation would be a good predictor for emissions. Model 2 adds a dummy variable that takes a value of one for hours during the ozone season and a value of zero otherwise. The predictive power of these models is significantly stronger (R^2 values of 0.84 for the OTC and 0.96 for PJM). These results strongly suggest that the OTC NO_X Budget has had a very strong affect on emissions from large power plants, which is unsurprising.

More importantly, models 3-6 add fuel and electricity prices (and co-generators for the OTC data) to models 1 and 2. While the coefficients for these specifications are significant, and they improve the predictive power of the regression models without the ozone season dummy variable (models 3 and 5), they have very little or no effect with the dummy *is* in the model (models 4 and 6). This strongly suggests that fuel and electricity prices have little or no effect on NO_X emissions of large power plants in the OTC NO_X Budget program relative to the requirements of the program itself. Very similar results are obtained with a variety of specifications and when allowance prices are included.

Table 5: Regression models for large OTC plants for all of 2000

Model 1-OTC					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.10	175	0	N	8,760
Constant	5,100	13	0	R^2	0.78
				Adj. R^2	0.78
Model 2-OTC					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.37	373	0	N	8,760
D_SEASON	-16,600	-162	0	R^2	0.94
Constant	6,400	34	0	Adj. R^2	0.94
Model 3-OTC					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	2.94	234	0	N	8,760
COGEN	3.79	66.0	0	R^2	0.90
COALPRICE	192,000	29.6	0	Adj. R^2	0.90
GASPRICE	-5050	-18.0	0		
Constant	-243,000	-27.0	0		
Model 4-OTC					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.33	381	0	N	8,760
COGEN	-.427	-8.05	0	R^2	0.96
COALPRICE	104,000	24.5	0	Adj. R^2	0.96
GASPRICE	-1,870	-10.3	0		
D_SEASON	-16,900	-111	0		
Constant	-35,200	-9.36	0		

Table 6: Regression models for large PJM plants for all of 2000

Model 1-PJM					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.00	125	0	N	8,760
Constant	-27,800	-40	0	R^2	0.64
				Adj. R^2	0.64
Model 2-PJM					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.24	200	0	N	8,760
D_SEASON	-14,400	-104	0	R^2	0.84
Constant	-287,00	-61	0	Adj. R^2	0.84
Model 5-PJM					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.07	108	0	N	8,760
ELECTPRICE	-16.3	-4.2	0	R^2	0.64
Constant	-29,200	-37.9	0	Adj. R^2	0.64
Model 6-PJM					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.18	167	0	N	8,760
ELECTPRICE	15.6	5.98	0	R^2	0.84
D_SEASON	-14,500	-104	0	Adj. R^2	0.84
Constant	-27,400	-53	0		

The third step in the regression analysis applied model 3 to data from the worst ozone episode in 2000 and two other periods in that year of the same duration with very similar total electricity generation, one during the ozone season and one not during the ozone season. . This analysis parallels the analysis above associated with Table 4 and Figure 4. The key regression results are presented below in Table 7. The R^2 values for these models are extremely high, but the sign and significance of most of the variables change from one model to another. Only the coefficient for electricity generation is significant and has the expected sign in all three models. This suggests that generation can be an extremely good predictor of NO_X emissions over short periods of time, and that some of the residuals in other (annual) models applied to annual data may be associated with the operation of different power plants over the course of the year due to scheduled (and unscheduled) maintenance. If it is assumed that within each of the three-day periods that the same power plants are operated, the results in Table 7 indicate extremely stable operation. The idea that power plant operators might change plant operation as electricity prices change over the course of the day (power prices often have a diurnal pattern) is not supported by this analysis.

Interesting but less obvious are the values taken by the generation coefficient in the three models shown in Table 7. For comparison, the coefficient found using annual data is 2.94 (see Table 5). The coefficient for the ozone episode (00c) is lower, while the coefficient for the in-season comparison (00d) is close to the annual value and the coefficient for the non-season (00e) value is higher. (The coefficient for generation when model 3 is applied to October-December data is similar to the non-season value.) A higher value for the non-season coefficient is expected since this implies that power plants in the OTC produce more NO_X when the NO_X Budget program is not in force, which was observed in models 2, 4, and 6. However, it is not so clear why the value for the ozone episode itself should be so low. Investigating more ozone season comparisons or using a disaggregated analysis may be needed to resolve this issue.

Nonetheless, this third step of the regression analysis provides no support for the idea that the NO_X Budget program has led to increased emissions during ozone episodes, undercutting concerns about temporal hotspots.

Table 7: Regression models for large PJM plants for 2000

Model 3-00e: ozone episode					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	2.27	12.6	0	N	72
COGEN	2.71	1.94	0.057	R^2	0.98
COALPRICE	-12,800	-0.877	0.384	Adj. R^2	0.98
GASPRICE	-205	-0.230	0.818		
Constant	213,000	38.7	0.228		
Model 3-00s: comparison during ozone season					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	3.01	19.1	0	N	72
COGEN	1.74	1.47	0.240	R^2	0.99
COALPRICE	37,900	4.30	0.0001	Adj. R^2	0.99
GASPRICE	114	4.59	0		
Constant	-517,000	-4.37	0		
Model 3-00n: comparison not in the ozone season					
Variable	Coefficient	*t* – statistic	*p* – value		
POWERGEN	4.02	23.6	0	N	72
COGEN	-2.81	-2.82	0.0062	R^2	0.96
COALPRICE	-2,830	-0.208	0.836	Adj. R^2	0.96
GASPRICE	41.4	0.195	0.846		
Constant	58,100	0.339	0.736		

Discussion

The analysis presented here supports the idea that temporal variations in NO_X emissions occur during the ozone season in the Northeast, with higher than average emissions occurring during ozone episodes. However, these 'hotspots' are very closely associated with increases in electricity generation, and would likely occur even with rate-based command and control regulation. The statistical analysis showed that while generation is by far the most important driver of NO_X emissions in the OTC NO_X Budget, the effect of the program is very significant as well.

More importantly, this research discovered no interview or statistical evidence for the 2000 ozone season that operators of large power plants respond to fuel or electricity prices by adjusting (in aggregate) plant operation to change NO_X emissions. This result is further supported by the comparison of a specific ozone episode with periods similar from an electric generation standpoint. Power plants appear to operate the same during high ozone periods as other periods of the year.

Policies, both proposed and adopted, for dealing with hotspots in emission trading systems have tended to introduce uncertainty and inflexibility into the markets. These have (or would have) reduced the efficiency of the market and thus limited the cost savings available, and in the case of RECLAIM they probably contributed to the failure of the program. While there is no doubt that emission trading systems may hypothetically increase the likelihood of hotspots, concern for this problem may be over-stated. A better policy may be to avoid provisions that limit trading or banking in the hopes of limiting temporal hotspots, but institute a regular system of review that would impose such limits if the potential for such a problem arose. These policies should be prospective, not retrospective, in order to minimize the uncertainty they introduce into the market.

Nonetheless, while this research has turned up no evidence that emission trading enhances any tendency towards greater temporal hotspots, it is undeniable that the flexibility built into such systems plus the mismatch between the phenomenon of concern and the regulatory period makes such a problem possible. Further, this study has some limitations. Most important is probably the fact that the OTC NO_X market is relatively small and illiquid, which limited participation and possibly limited the opportunity for firms to vary plant operation to optimize revenues associated with NO_X controls and allowance purchases. This would be accentuated by the fact that only the first three years of the program are evaluated and for the first, at least, there was very little familiarity with the program and no bank of allowances saved up. The relatively low prices for NO_X allowances (compared to the prices for power) may also be a factor – things may change as the cap decreases.

This paper suggests a number of areas for further research. One obvious issue would be to continue to look for temporal hotspot problems in C/T systems as the caps become tighter. A second would be to conduct a more detailed and disaggregated analysis of plant dispatch and utilization to verify the underlying causes of the residuals in the regressions above and the values that the coefficients take. Third, an analysis of the NO_X Budget program for spatial hotspots is clearly needed. Finally, air quality modeling may be needed to determine if any spatial and temporal differences in *emissions* caused by the OTC NO_X Budget have a significant effect on pollution concentrations or on health.

References

Atkinson, S. E. and T. Tietenberg (1987). "Economic Implications of Emissions Trading Rules for Local and Regional Pollutants." Canadian Journal of Economics **20**: 370.

Bernstein, M., A. Farrell and J. Winebrake (1994). "The Environment and Economics: The Impact of Restricting the SO2 Allowance Market." Energy Policy **22**(9): 748-754.

Blumsack, S., D. Perekhodstev and L. B. Lave (2002). "Market Power in Deregulated Wholesale Electricity Markets: Issues in Measurement and the Cost of Mitigation." Electricity Journal **15**(9): 11-24.

Burtraw, D. and E. Mansur (1999). "Environmental effects of SO2 trading and banking." Environmental Science & Technology **33**(20): 3489-3494.

Bush, G. W. (2002). Clear Skies Initiative. Washington, DC, The White House. Press Release.

Campbell, S. M. and A. S. Holmes (1993). "Going Once, Going Twice, Sold! EPA Auctions Pollution Rights." New York Law Journal: S10.

Carlson, C., D. Burtraw, M. Cropper and K. L. Palmer (2000). "Sulfur dioxide control by electric utilities: What are the gains from trade?" Journal of Political Economy **108**(6): 1292-1326.

Chinn, L. N. (1999). "Can the market be fair and efficient? An environmental justice critique of emissions trading." Ecology Law Quarterly **26**(1): 80-125.

Dorris, G., J. Agras, S. Burrows, M. McNain and S. Reynolds (1999). Development and Evaluation of a Targeted Emission Reduction Scenario for NOx Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ). Washington, DC, U.S. Environmental Protection Agency. November 24.

Drury, R. T. (1999). "Pollution Trading and Environmental Injustice: Los Angeles' Failed Experiment in Air Quality Policy." Duke Environmental Law and Policy Forum **9**: 231.

Dudek, D. J. and J. Goffman (1992). "Can Preapproval Jump-Start the Allowance Market ?" Electricity Journal: 12-17.

Farrell, A. (2000). "The NOx Budget: A Look at the First Year." Electricity Journal **March**: 83-92.

Farrell, A. E. (2001). The Political Economy of Interstate Public Policy: Power-Sector Restructuring and Transboundary Air Pollution. In Improving Regulation. S. Farrow and P. Fischbeck, Eds. Washington, DC: RFF Press. pp. 115-141.

Farrell, A. E. (2003). Clean Air Markets. In Encyclopedia of Energy. C. Clevelenad, Ed.: Academic Press. pp. forthcoming.

Farrell, A. E., R. Carter and R. Raufer (1999). "The NOx Budget: Costs, Emissions, and Implementation Issues." Resource & Energy Economics **21**(2): 103-124.

Farrell, A. E. and G. Morgan (2003). Multi-Lateral Emission Trading: Heterogeneity in domestic and international common pool resource management. In The Commons in the New Millenium: Challenges and Adaptation. E. Ostrom and N. Dolšak, Eds. Cambridge: MIT Press. pp. forthcoming.

Foster, V. and R. W. Hahn (1995). "Designing More Efficient Markets: Lessons From Los Angeles Smog Control." Journal of Law and Economics **38**(1): 19-48.

Fromm, O. and B. Hansjurgens (1996). "Emission trading in theory and practice: an analysis of RECLAIM in Southern California." Environment and Planning C: Government and Policy **14**: 367-384.

Israels, K., R. Grow, A. Campbell, A. Liddell, A. Schwarz and D. Pekelney (2002). An Evaluation of the South Coast Air Quality Management District's Regional Clean Air Incentives Market - Lessons in Environmental Markets and Innovation. San Francisco, U. S. Environmental Protection Agency Region 9. November. 69. http://www.epa.gov/Region9/air/reclaim/index.html

Johnson, S. L. and D. Pekelney (1996). "Economic assessment of the regional clean air incentives market: A new emissions trading program for Los Angeles." Land Economics **72**(3): 277-297.

Milford, J. B., D. F. Gao, A. Zafirakou and T. E. Pierce (1994). "Ozone Precursor Levels and Respones to Emissions Reductions - Analysis of Regional Oxidant Model Results." Atmospheric Environment **28**(12): 2093-2104.

Nash, J. R. and R. L. Revesz (2001). "Markets and geography: Designing marketable permit schemes to control local and regional pollutants." Ecology Law Quarterly **28**(3): 569-661.

Nobel, C. E., E. C. McDonald-Buller, Y. Kimura and D. T. Allen (2001). "Accounting for spatial variation of ozone productivity in NOx emission trading." Environmental Science & Technology **35**(22): 4397-4407.

Nobel, C. E., E. C. McDonald-Butler, Y. Kimura, K. E. Lumbley and D. T. Allen (2002). "Influence of population density and temporal variations in emissions on the air quality benefits of NOx emission trading." Environmental Science & Technology **36**(16): 3465-3473.

Possiel, N. C. and W. M. Cox (1993). "The Relative Effectiveness of NOx and VOC Strategies In Reducing Northeast U.S. Ozone Concentrations." Water, Air, and Soil Pollution **67**: 161-179.

Raufer, R. (1998). Pollution Markets in a Green Country Town: Urban Environmental Management in Transition. Westport, CT, Praeger Publishers.

Solomon, B. and K. Rose (1992). "Making a Market for SO2 Emissions Trading." The Electricity Journal **5**(July): 58-66.

Stavins, R. (1997). "What can we learn from the grand policy experiment? Lessons from SO2 allowance trading." Journal of Economic Perspectives **12**(3): 69-88.

Swift, B. (2001). "How Environmental Laws Work: An Analysis of the Utility Sector's Response to Regulation of Nitrogen Oxides and Sulfur Dioxide Under the Clean Air Act." Tulane Environmental Law Journal **14**(Summer): 309.

U.S. Environmental Protection Agency (1998). Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule. 63*FR*57356. October 27

Zhou, H., K. F. Cen and J. B. Mao (2001). "Combining neural network and genetic algorithms to optimize low NOx pulverized coal combustion." Fuel **80**(15): 2163-2169.

Lessons from Phase 2 Compliance with the U.S. Acid Rain Program

A. Denny Ellerman[1]

INTRODUCTION

The acid rain provisions of the 1990 Clean Air Act Amendments, included in Title IV, required fossil-fuel-fired electricity generating units to reduce sulfur dioxide (SO_2) emissions by 50% in two phases. In the first, known as Phase I and extending from 1995 through 1999, generating units of 100 MW^e of capacity and larger, having an SO_2 emission rate in 1985 of 2.5 lbs. per million Btu (#/mmBtu) or higher, were required to take a first step and to reduce SO_2 emissions to an average of 2.5 #/mmBtu during these transitional years. Phase II, which began in 2000 and continues indefinitely, expanded the scope of the program by including all fossil-fuel-fired generating units greater than 25 MW^e and increased its stringency by requiring affected units to reduce emissions to an average emission rate that would be approximately 1.2 #/mmBtu at average annual heat or Btu input in 1985-87, and that would be proportionately lower for increased total fossil-fuel fired heat input.[2]

The behavior of affected units in Phase I has provided the answers to many questions about how tradable permit systems would work in practice: for instance, how electric utilities would use allowances and whether reasonably efficient allowance markets would develop. It has also been possible to answer questions about environmental effectiveness, patterns of abatement, opt-in behavior, cost savings, and

---

[1] Ellerman is executive director of the Center for Energy and Environmental Policy Research (CEEPR) at MIT and senior lecturer in the Sloan School of Management. The author is indebted to Paul Joskow for comments on an earlier draft, to Curtis Carlson and Byron Swift, who commented on the paper at the EPA workshop on market-based mechanisms at which the paper was first presented, and to Brice Tariel and Florence Dubroeucq for very capable research assistance. Funding by EPA STAR grant award #R-82863001-0 is gratefully acknowledged.

[2] The nation-wide Phase II cap on SO_2 emissions is 8.9 million tons, which is approximately the product of total baseline (average 1985-87) heat input and the emission rate target of 1.2 #/mmBtu. Since the cap is fixed, higher total heat input necessarily implies a lower average emission rate, and vice versa.

innovative activity associated with cap-and-trade programs.[3] Yet, the answers to some of these questions were necessarily incomplete, while other questions could not be addressed until Phase II began, such as: How much additional abatement would be provided by the four-fold increase in coverage and the tighter cap? How would the allowances banked in Phase I be used during Phase II? Was the degree of over-compliance in Phase I, which led to the accumulation of a large allowance bank, even reasonably optimal? Do new generating units, who receive no allowances, face any barriers to entry caused by the need to acquire allowances in the market? And finally, what will it all cost when the Phase II cap is fully phased in? This paper provides tentative answers to these questions based on the analysis of data from the first two years of Phase II.

THE DISTRIBUTION OF ABATEMENT

Phase 1 and Phase II units

Any analysis of abatement and compliance must distinguish between those units for which 2000 was only the sixth year of being subject to the requirements of Title IV and those for which 2000 was the first year.[4] Table 1 shows the relevant statistics for these two groups of units for the year 2001.

Table 1. Title IV Compliance Behavior, 2001

	Phase I Units (374 Units)	Significant Phase II Units (1,420 Units)	Total (1,794 Units)
Heat Input (trillion Btu)	6,007 (24%)	18,730	24,737
Emissions (000 tons SO_2)	4,041 (38%)	6,571	10,612
Emission Rate (lbs SO_2/mmBtu)	1.35	0.70	0.86
CF Emissions (000 tons SO_2)	9,304 (55%)	7,622	16,926
Abatement (000 tons SO_2)	5,263 (83%)	1,051	6,314
Allowances (000 tons SO_2)	2,914 (32%)	6,199	9,113
Banking (000 tons SO_2)	(1,127) (75%)	(372)	(1,499)

[3] The principal works evaluating compliance behavior in Phase I are Burtraw (1996), Carlson et al. (2000), Ellerman et al. (2000), Joskow et al. (1998), Montero (1999), Popp (2001), Schmalensee et al. (1998), Swift (2000), and Swift (2001). Ellerman (2003) provides an update that includes the first years of Phase II and Ellerman et al. (2003) provide a more general treatment that includes other emissions trading programs.
[4] About 100 of the Phase II units opted into and out of Title IV in one or more years of Phase I, but none of these units were continuously affected until 2000.

Three hundred seventy-four electrical generating units were subject to Title IV during all five years of Phase I, including 263 units that were mandated to be subject to Title IV beginning in 1995 and another 111 units that voluntarily opted into Phase I for all five years. A total of nearly 4,000 unit accounts were subject to Title IV requirements in 2000 and 2001, but many of these were for units that were yet to be built and about 1200 generated little electricity and virtually no emissions. For the purpose of analyzing the Phase II response, inclusion of these units provides little information about compliance behavior since they account for less than 2% of fossil-fuel heat input and less than 0.2% of emissions.[5] Instead, and unless otherwise stated the analysis below is based on the 374 Phase I units and 1420 Phase II units that can be considered significant either because of their generation or their emissions. By definition, the Phase II units are smaller and lower emitting units, but they accounted for approximately 45% of 2001 counterfactual emissions and they received 68% of the allowances.

While the Phase II units account for the majority of allowances and heat input (and therefore generation), they account for a relative small part of the abatement that can be attributed to Title IV. The reduction of SO_2 emissions in 2001 due to Title IV is 6.3 million tons of which five-sixths occurred at the Phase I units. As a group, these units have reduced emissions by 57%, while the comparable percentage for the Phase II units is 14%. As a result, the share of emissions attributable to the Phase I units, the "big dirties," has declined from approximately 55% of the national total to 38%.

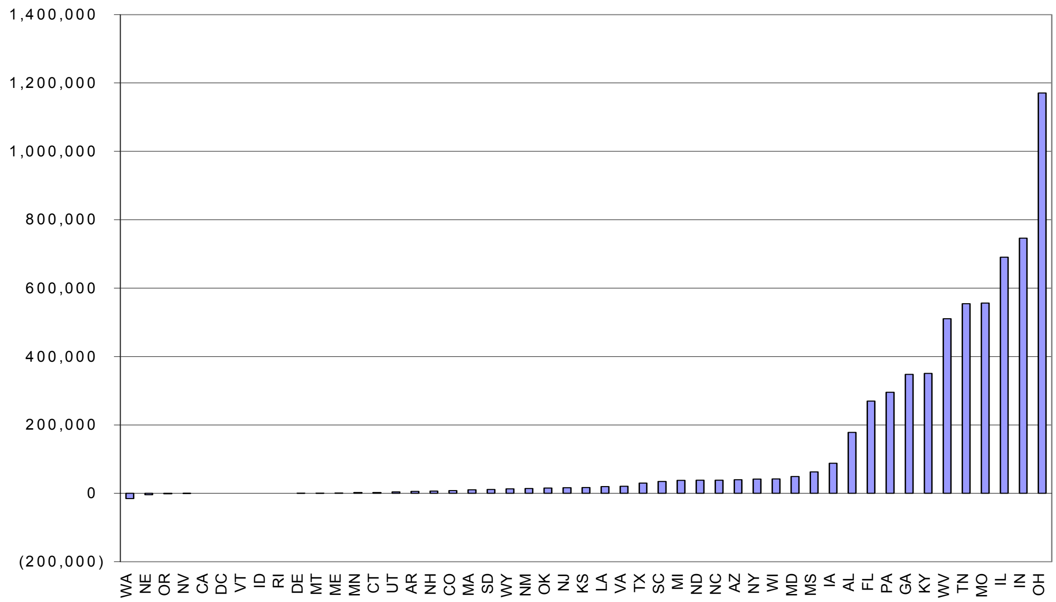
As of 2001, both Phase I and Phase II units are relying upon the accumulated Phase I bank of allowances to cover emissions that are higher in the aggregate than the 2001 allowances allocated to these two categories. The use of the bank is however much greater for the Phase I units; their emissions are about 39% higher than the aggregate allowance allocation for the Phase I units while the comparable number for the Phase II units is 6%.

[5] Technically, the criteria for inclusion as a significant unit was having heat input greater than 1×10^{12} Btu in two of the seven years, 1995-2001, or heat input greater than 5×10^{12} Btu in any one of those years. For a unit with a heat rate of 10,000 Btu/kwh, heat input of 1×10^{12} Btu would generate approximately 100,000 Mwh in a year, which would imply a 11% capacity factor for a 100 MW unit.

The Geographic Distribution of Abatement

Figure 1 show the geographical distribution of abatement in 2000.

Figure 1. Title IV Emission Reduction by State, 2000 (tons SO_2)



Eleven states (OH, IN, IL, MO, TN, WV, KY, GA, PA, FL, and AL) account for 90% of national abatement. Excluding the three southeastern states of GA, FL, and AL, 77% of the abatement is occurring in the Mid-west. This geographic concentration of abatement in the Mid-west reflects the predominance of the Phase I units in this region. Virtually all of the Phase I units are located east of the Mississippi River and the heaviest concentration of emissions prior to enactment of Title IV was in the Mid-west.

Since Title IV did not require abatement in any specific geographic location, one might ask: Why did the abatement occur where it was desired? The increased availability and attractiveness of lower sulfur coals in the Midwest provides part of the answer, but an equally important cause is the changed incentive structure of cap-and-trade programs. Deep abatement technologies, such as scrubbers, are more economic at units where a lot of sulfur can be removed, that is, at large units burning high sulfur coal, which in this instance were located in the Midwest. When the owners of affected units must pay a price (in the form of an allowance surrendered) for every ton of emissions, these large and high emitting units will offer the most attractive locations for scrubbers. In fact, 23 of the 30 retrofitted scrubbers installed in response to Title IV are located in the Midwest.

By Abatement Technique

Table 2 provides a breakout of emissions reductions in 2001 by abatement technique, that is, whether by scrubbing or switching to lower sulfur fuels.

Table 2: 2001 Emission Reduction by Technique and Fuel

000 tons	Phase I Units	Phase II Units	Total
Scrubbing	2,048	263	2,311
Fuel Switching	3,215	788	4,003
Total	5,263	1,051	6,314

Scrubbing accounts for approximately 37% of the abatement in 2001 and virtually all of this abatement (1,993,000 tons) comes from new scrubbers installed on 30 Phase I units as a result of Title IV.[6] These thirty units, located primarily in the Midwest and constituting 3% of the generating capacity and 4% of the 2001 heat input at Title IV units, accounted for 32% of total abatement. The remaining reductions attributed to scrubbing are reductions in excess of the percentage reduction required of scrubbers under non-Title IV regulation, which is typically 70% to 90%. Switching to lower sulfur fuels occurred almost exclusively (99.9%) at coal-fired units and it consisted entirely of switching to lower sulfur coals. The remaining 0.1% of the emission reduction by switching occurred at oil-fired units, which were switched either to lower sulfur petroleum products or to natural gas. No coal units have been switched to natural gas because the price of natural gas is too high to justify abatement by this means.

First Year Effect

One of the most interesting phenomena of both Phase I and Phase II is that the largest reduction of emissions was made in the first year that units were subject to Title IV, which is to say, the first year in which they were required to pay a price for every ton of SO_2 emissions. Figures 2 and 3 show this effect for the 374 Phase I units that first

[6] 27 of these units were installed at the beginning of Phase I. Since 1998, when allowance prices first exceeded $200/ton, at least eight new retrofit scrubbers have been announced and three of these were on-line in 2001.

became subject to Title IV in 1995 (by law or through opting-in voluntarily) and have been so continuously since then and the Phase II units that became subject to Title IV in 2000.

Figure 2. Phase I unit emissions, allowances and counterfactual emissions

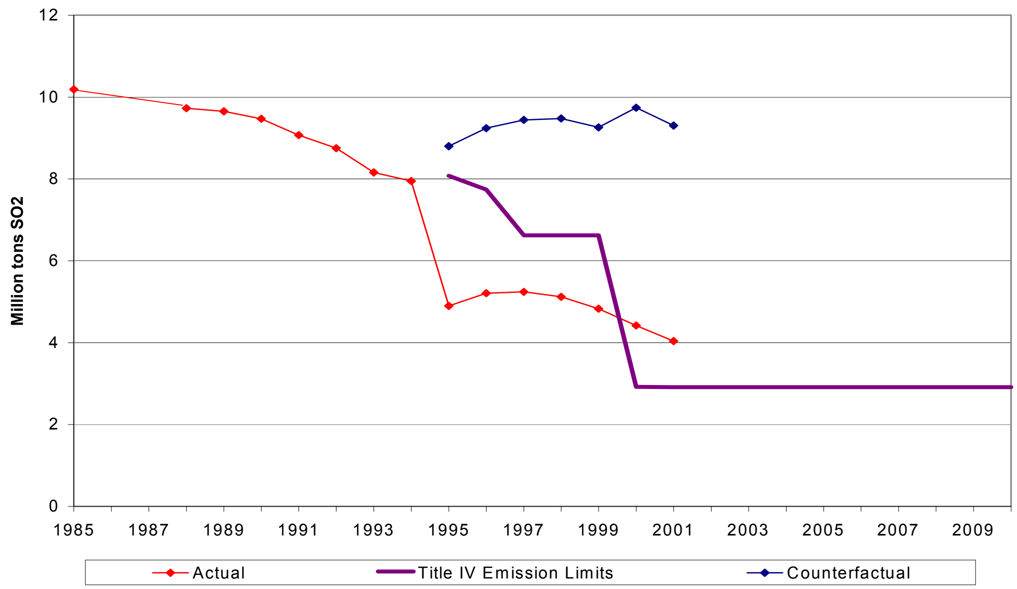
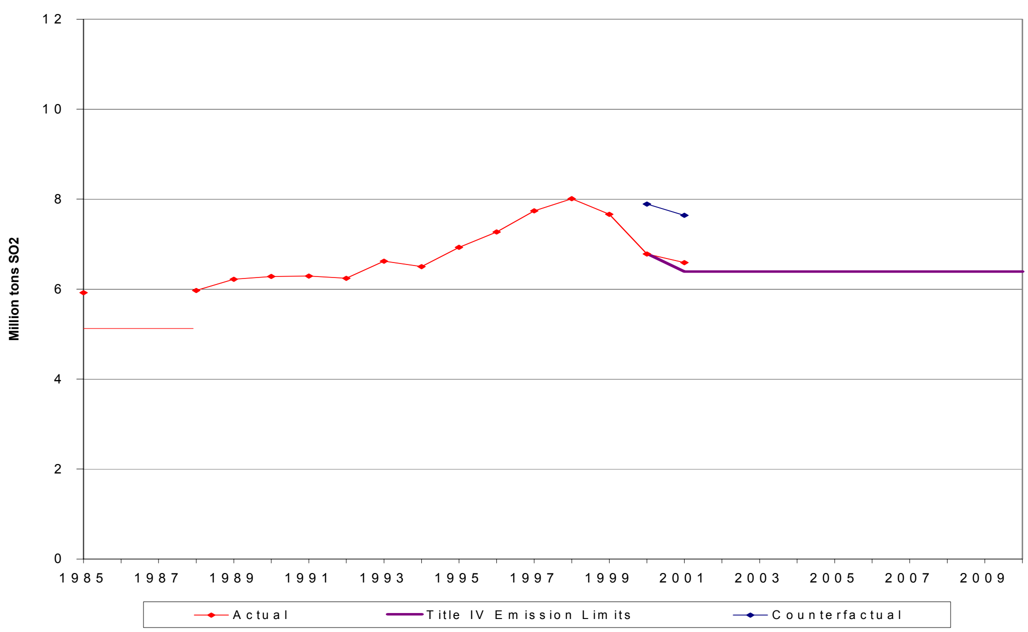


Figure 3. Phase II unit emissions, allowances, and counterfactual emissions



In both of these figures, the red line beginning in 1985 and continuing through 2001 depicts the evolution of actual SO_2 emissions; the lines beginning in 1995 in Figure 2 and in 2000 in Figure 3 and continuing to the right-hand side of each figure represents the total number of allowances issued to these units for each year; and the shorter line consisting of seven points in Figure 2 and two points in Figure 3 provides an estimate of counterfactual emissions, what emissions would have been for these units if Title IV had not been in force. The notable feature for each subset of generating units is the large reduction in emissions that is observed in the first year that Title IV took effect.

This first-year effect is particularly striking for the Phase I units. A steady decline in the trend of emissions can be observed in the late 1980s and early 1990s, but the reduction from 1994 to 1995 was much greater than any year-to-year decline observed before.[7] Title IV occasioned this sharp one-year decline; there simply is no other explanation. It is the more remarkable in that it can be seen as completely voluntary, at least with respect to the timing of the emission reduction since the total number of allowances issued for 1995 was in fact not very constraining.

The first-year effect is not as large in absolute or percentage terms for the Phase II units because these relatively low emission units contribute less to the aggregate emissions, but it is still noticeable. The start of Phase II broke what had been a steady upward trend in SO_2 emissions for these units that contrasts with the pre-Title IV trend for the Phase I units. In 2000, aggregate emissions for Phase II units were virtually the same as the number of allowances issued to these units, but the pattern beneath the aggregate is highly variable. Approximately 60% of the Phase II units receive more allowances than needed to cover calculate counterfactual (and generally actual) emissions; the surplus is effectively transferred to other Phase II units, generally located east of the Mississippi, that received fewer allowances than those unit's pre-Title IV and estimated 2000 counterfactual, emissions.[8]

---

[7] Ellerman and Montero (1998) the declining trend in SO_2 emission prior to the onset of Phase I to the deregulation of railroads which made low sulfur western coal cheap in the Midwest. The appendix by Schennach in Ellerman et al. (2000) provides an econometric estimate that separates the amount of pre-1995 decline due to railroad deregulation and to anticipation of Title IV.

[8] Counterfactual emissions are calculated as the product of the observed, pre-Title IV emission rate and actual heat input for the year in question. For instance, 2000 counterfactual emissions for any given unit is

BANKING

One of the prominent features of Phase I was the accumulation of a bank of allowances that totaled 11.65 million tons at the end of 1999. Although most observers believed that these allowances would be used during the first decade of Phase II, it was never clear whether the amount of banking in Phase I was the result of reasonably rational banking programs implemented by the owners of Phase I affected units, which is to say, whether the level of banking was economically justified..

The effect of Phase II on Phase I unit emissions

One important sign that the owners of Phase I affected units have been engaging in reasonably rational banking behavior is provided by the change in total emissions from these units between 1999 and 2000, when the allocation of allowances for these units was reduced by about 50%. Economic agents who engage in reasonably efficient banking programs would ignore year-to-year changes in the number of allowances allocated and abate according to a banking program based on the cumulative required emission reduction over the relevant economic horizon—essentially smoothing abatement over time.

Figure 2 shows that the 56% reduction in allowances from 1999 to 2000 had little effect on emissions, which declined by 8% between the two years. The only change from 1999 to 2000 was the change in the banking position of these units; in 1999 they continued to bank allowances and in 2000 they started to draw down the accumulated Phase I bank.. The general shape in the trajectory of emissions, and in the net changes to the bank, is what would be predicted by economic theory when agents are able to redistribute emissions over time in a cost-minimizing fashion and they are faced with a sharp discontinuity in the temporal allocation of allowances (Schennach, 2000).

Optimality of Banking

The smooth path of aggregate emissions from Phase I units and the concomitant start of the draw down of the accumulated allowance bank does not imply that banking

---

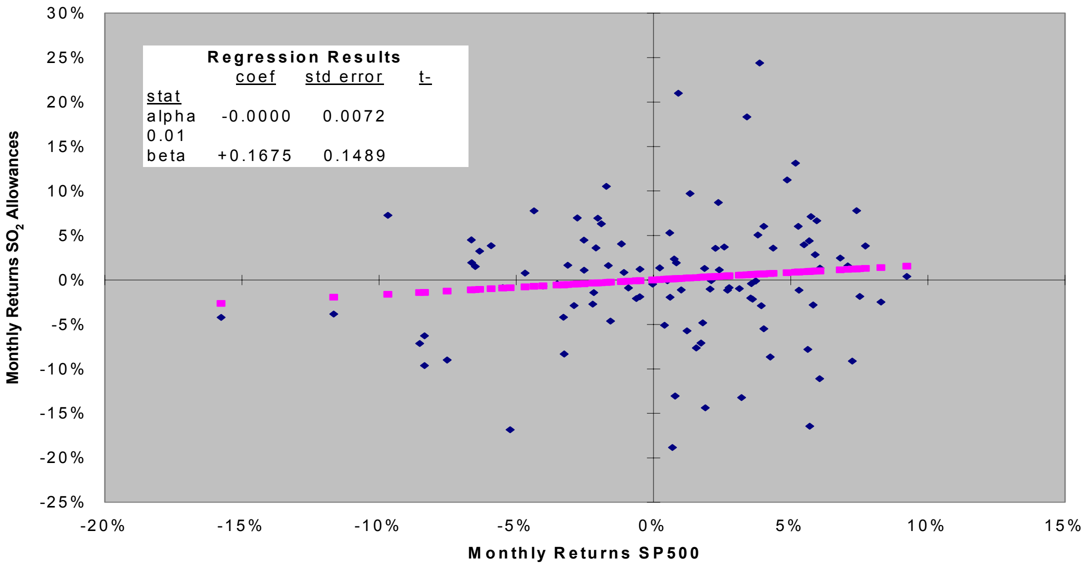
the product of that unit's 1998 emission rate and its 2000 heat input. Aggregate counterfactual emissions for any year is calculated by summing all the individual units.

behavior has been optimal, although it does eliminate the possibility of irrational hoarding, a common concern in the early days of Title IV. Any judgment on temporal efficiency requires that an appropriate discount rate be chosen, which is a non-trivial task.

The usual assumption has been that the owners of electric utilities would use an internal discount rate reflecting their weighted cost of capital; yet, finance theory is clear that the cash flows associated with certain projects or assets should be discounted by a rate reflecting the degree of undiversifiable risk, that is, the extent to which the returns from a particular type of asset vary with the returns from a well diversified portfolio of equities, such as the S&P 500. By the Capital Asset Pricing Model, the appropriate discount rate is the sum of the risk-free rate, associated with Treasury bills or notes, and a risk premium that depends on the asset's "beta," which is the slope of the line regressing the returns from the particular type of asset on the returns from a well-diversified portfolio of equities over a succession of periods. The empirically observed additional return associated with a well-diversified portfolio of equities (in comparison with T-bills for instance) is known as the equity premium for the undiversifiable risk of such a portfolio. The appropriate discount rate for any specific asset, such as SO_2 allowances, is then the risk-free rate plus the product of the asset's beta and the market equity premium. For example, a beta of 1.0 implies that on average the percentage returns from the specific asset (defined as the change in price of the asset plus any dividend payment) are the same as the general equity market; and lower or higher betas imply a lower or higher discount rate for the cash flows associated with the specific asset.

The capital asset pricing model is useful because it provides a means for determining the appropriate discount rate for any asset that is priced in some market. SO_2 allowances are financial assets whose ultimate value depends on the abatement costs avoided by their use for covering emissions in some period. They are also bought and sold in what appears to be a reasonably efficient market so that the returns from holding SO_2 allowances can be easily calculated and compared to those from holding a well-diversified portfolio of equities. Such a comparison is made in Figure 4 for the period from October 1994 through March 2003.

Figure 4. Returns from holding SO2 Allowances and the S&P500



The straight, slightly upward sloping line is the regression line, and its slope indicates the beta, which is statistically insignificantly different from zero. This result indicates that no correlation exists between the monthly returns from SO_2 allowances and the S&P500.[9] When the return from holding a diversified portfolio for some period is positive, the return from holding an SO_2 allowance in the same period is as likely to be negative as it is to be positive. Equivalently, SO_2 allowances constitute a zero-beta asset and this result implies that the appropriate discount rate for SO_2 allowances is the risk-free rate.[10]

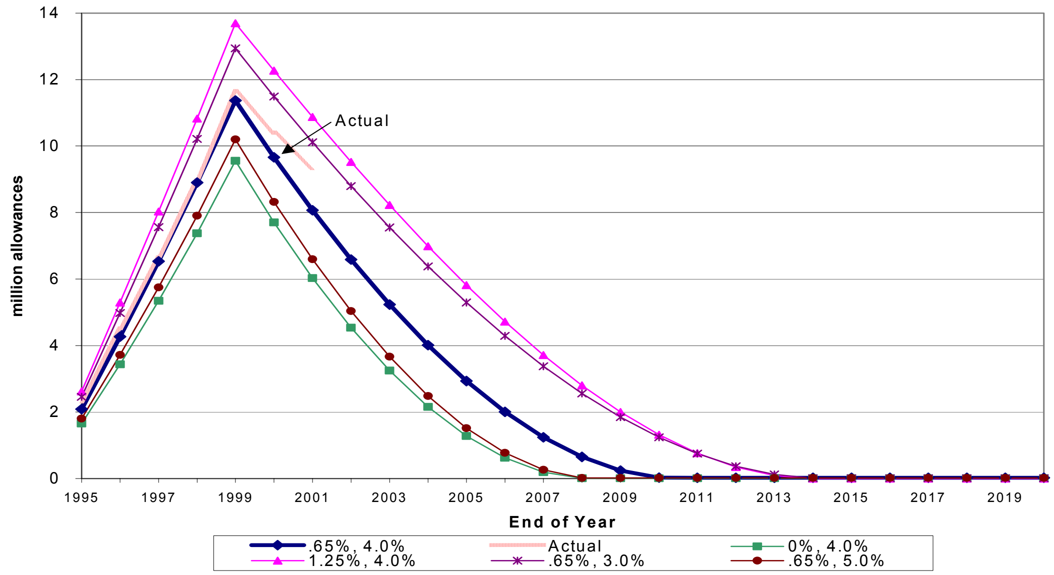
It would take this paper to far afield to delve into the construction of an appropriate discount rate for SO_2 allowances, such as how to determine the risk-free rate and over what period of time; however, the result of that analysis, as developed more fully in Ellerman and Montero (2002), is given in Figure 5.

---

[9] Regressions on different market indices, for differing periods of time, and with corrections for serial correlation give similar results.

[10] It must be emphasized that the risk that is measured is systemic or undiversifiable risk, not asset specific risk. The latter can be reduced and avoided by constructing a portfolio with an appropriate weighting of assets whose returns are negatively correlated with the specific risk being diversified.

Figure 5. Simulation of optimal Title IV banking



The five peaked lines extending from 1995 through varying years in Phase II represent optimal aggregate bank holdings depending on plausible assumptions concerning discount rates and the expected growth of SO_2 emissions over the banking period. The fuzzy line that runs through 2001 represents actual aggregate bank holdings and it closely tracks the optimal path for a real discount rate of 4.0% and an expected growth of emissions of 0.65%. These are in fact reasonable assumptions for the real risk-free discount rate from the mid-1990s through 2001 and for pre-1995 expectations of expected SO_2 emissions growth without Title IV. However, the important point is not that the actual path tracks this particular line, but that it falls within the paths described by alternative plausible assumptions concerning real risk-free discount rates—3.0% and 5.0%—and for the growth of counterfactual emissions—0% and 1.25% per annum. The real risk-free discount rate varies over time, as do expectations of expected growth in counterfactual emissions, but these bounds fairly describe the variation in these parameters since Title IV began.

It would be too much to claim that banking has been optimal in any exact sense, but the lines in Figure 5 describe the range of reasonably efficient banking programs given reasonable assumptions about the most important parameters determining banking behavior. The envelope described by these banking programs would predict an end-of-Phase I bank of between 9.5 million tons and 13.5 million tons and the complete draw down of the bank sometime between 2008 and 2013. This envelope is consistent with what has been observed and what is expected, assuming no changes to Title IV during the remainder of the banking period. In summary, the response to the banking provisions of Title IV provides further evidence economic agents respond in a rational, cost-minimizing way when market-based incentives are made available.

NEW UNITS

A frequently maligned feature of Title IV is the endowment of allowances to incumbents (as of 1985-87) without any provision for allowances to new entrants. This feature is often decried as a barrier to entry for new generating units, an issue of particular concern when wholesale power markets are deregulated. This feature of Title IV could not be observed in Phase I, since existing plants only were included. However, any new fossil-fuel-fired generating unit of more than 25 MW^e that has come on line since enactment of the legislation in 1990 would be covered in Phase II, so that this effect can now be observed.[11]

One way to evaluate the effect on new units is to observe the frequency of generating units that were not allocated allowances. Zero-allowance units are not necessarily new units since re-activated, mothballed units not operating in 1985-87 would also not receive allowances, and there were some of these. Nevertheless, all new units would be zero-allowance units and the crux of the argument about barriers to entry concerns the absence of an allowance allocation. Of the nearly 3,000 units subject to reconciliation and emitting some SO_2 during 2000-2001, 981 are zero-allowance units, almost a third. This large number reflects mostly the increase in new gas-fired capacity that has been observed in 2000 and 2001.

Table 3 provides an accounting of these zero-allowance units by the time when they first appeared as generating units. In this presentation, a division is made between

[11] A few units that were in the planning stage in 1990 received contingent allowance allocations in the Title IV legislation. In the following analysis, three of these units that were operating in 2000 and 2001 have been excluded.

Phase II units that make a significant contribution to heat input or emissions (1420 units), which have been cited above, and the remaining units (1200) with small contributions to aggregate heat input (1-2% of the total) and emissions (≈ 0.2%). Since many of the new units were used for peaking purposes only or were only starting up as combined cycles in 2001, any assessment of the role of zero-allocation units must include these "remaining" or "insignificant" Phase II units.

Table 3. Zero-allowance Phase II units, by time of first generation

	Significant Units	Remaining Units	Total Phase II
Online prior to 2000	109	264	373
New in 2000	34	189	123
New in 2001	31	354	385
Total	174	807	981

Nearly all of the zero-allowance units are new, gas-fired peaking or combined cycle units that emit little SO_2, but a small number are not. In 2001, 61 units had an average emission rate higher than 0.05 lbs/SO_2 per mmBtu, which implies they were burning a petroleum product or coal; and 20 emitted more than 100 tons of SO_2 during the year. These small numbers might be used to argue that the absence of an allowance endowment discouraged new coal or oil capacity, but it is more likely that the compelling economics of gas-fired peaking and combined cycle generation (at least before the recent and persistent higher price levels for natural gas) explain this phenomenon. At the very least, it is evident that the lack of an allowance endowment does not impede the entry of new low-emitting generation capacity.

Quite apart from the issue of barriers to entry, the new gas-fired units have had a significant effect on SO_2 emissions. The year 2001 was the first year since 1992 in which the heat input into fossil fuel fired generating units declined thereby breaking what had been an eight-year succession of rising demand for fossil-fuels for the generation of electricity. The 3.2% decline in heat input from 2000 to 2001was the more remarkable in that fossil fuel fired generation of electricity in these two years was approximately constant. The explanation lies in the significant increment of new gas-fired combined cycle generating capacity that came on line in 2001.

The differing trends in fossil-fuel fired generation and fossil-fuel heat input due to the new combined cycle units emerges clearly from the latest EIA data, as shown in Table 4.

Table 4: Generation and Heat Input at Fossil-fuel fired Generating Units, 1999-2001

	1999	% Chg	2000	% Chg	2001
Generation (000 Gwh)	2,578	+4.31%	2,689	+0.07%	2,691
Coal	1,884	+4.46%	1,968	-2.79%	1,913
Oil/Gas	694	+3.89%	721	+7.90%	778
Heat Input (Quads)	23.45	+2.22%	23.97	-3.46%	23.14
Coal	19.33	+3.93%	20.09	-2.59%	19.57
Oil/Gas	4.12	-5.83%	3.88	-7.99%	3.57
Implied Efficiency					
All Units		+2.04%		+3.66%	
Coal Units		+0.51%		-0.21%	
Oil/Gas Units		+10.32%		+17.27%	

Source: EIA, Monthly Energy Review, February 2003

The effect of the new combined cycle units can be seen in the statistics for implied efficiency, which is the change of generation divided by the change in heat input. For instance, in comparing 2001 with 2000, fossil-fuel fired generation increased by less than .1% and heat input declined by 3.5%, which implies an improvement in efficiency of 3.66%. As can be seen from the decomposition by fuel, all of this comes from the oil/gas fired units. The efficiency of the coal units has been relatively constant in the aggregate, but the oil/gas generating units have improved in aggregate efficiency by about 10% in 2000 and 17% in 2001. The result in 2001, when demand for electricity was flat, has been a backing out of the coal units (-2.8%) and an increase in oil/gas generation (+7.9%). The improvement in efficiency also implies less demand for natural gas for generating electricity, a trend that is clearly evident in the EIA statistics (-8.0% from 2000 to 2001).[12]

The effect of the new gas-fired combined cycle generating units can be readily observed when the annual changes in emissions at generating units are decomposed into changes in emission rates at individual units, caused by fuel switching, and changes in heat input at those units. Table 5 provides an accounting of the changes in SO_2 emissions from 1999 to 2000 and from 2000 to 2001 by summing the observed changes at all affected generating units.

Table 5. Changes in SO_2 emissions by fuel and cause

000 tons SO_2	All Units	Coal Units	Oil/Gas Units
1999-2000 Changes	**- 1,254**	**- 1,132**	**- 122**
Emission Rate Changes	- 1,392	- 1,382	- 10
Heat Input Changes	+ 138	+ 250	- 109
2000-2001 Changes	**- 567**	**- 649**	**+ 83**
Emission Rate Changes	- 64	- 135	+ 71
Heat Input Changes	- 503	- 514	+ 12

Source: Derived from EPA CEMS data

The source of SO_2 reductions changes dramatically from the comparison of 1999 with 2000 and 2000 with 2001. All of the reduction in emissions from 1999 to 2000 can be attributed to an average lowering of emission rates at affected units, mostly by switching to lower sulfur fuels. This change is the first-year effect that has been discussed earlier: the downward shift in emission rates that occurs when units are first required to pay a price for all emissions. In contrast, nearly all of the reduction from 2000 to 2001 is due to lower heat input at affected units, which reflects the influx of new combined cycle

[12] The heat input data from the CEMS (Continuous Emissions Monitoring System) data collected by EPA confirms the general trend but not the magnitudes of improved generation efficiency for oil/gas units. For instance the CEMS data show oil/gas unit heat input to have increased by 2.7% from 2000 to 2001, instead of declining by 8.0%, as the EIA data indicate. A 2.7% increase in heat input would still imply some improvement in efficiency, given the increase in gas-fired generation, but not 17%. There are obvious problems of comparability concerning oil and gas units. While the EIA and EPA statistics agree closely with respect to heat input into coal-fired units, the disagreement for oil/gas fired units is large. EIA reports 3.57 quads of oil and gas heat input in 2001, while the EPA CEMS indicates 4.85 quads of oil and gas heat input, or 36% more.

capacity and the resultant backing out of coal-fired and single cycle oil and gas-fired generation. Had the new combined cycle units not been brought on line, the demand for electricity would have been met by existing generating capacity and SO_2 emissions would have been about 500,000 tons, or about 5%, higher than they were.

COST

No estimates of the actual cost of compliance with Title IV in Phase II have been made; however, two groups of analysts made ex post estimates of the cost of compliance in Phase I and both provided updated estimates of the expected cost in Phase II based on observed Phase I cost. These estimates of Phase II cost can be now be assessed based on the observed abatement in Phase II and allowance price behavior. The two ex-post evaluations of Phase I compliance cost were made by Carlson et al. (2000) and Ellerman et al. (2000) [hereafter, CBCP for the initials of the authors of Carlson et al. and MCA for *Markets for Clean Air*, the title of the book published by Ellerman et al.]

CBCP and MCA agree roughly on the cost of compliance in the early years of the Acid Rain Program. The latter estimates the cost of compliance at $726 million in 1995 and about $750 million in 1996, while the former places the cost at $832 million in 1995 and $910 million in 1996, all stated in 1995 dollars. These estimates are not as far apart as they would seem. Complete comparability is not possible because of differences in methodology; however, both treat scrubber expense in the same manner.[13] Although they largely agree on the fixed cost of scrubbers ($375 million in MCA and $382 million in CBCP), they differ significantly on the variable costs associated with scrubbers ($89 in MCA million and $274 million in CBCP).[14] CBCP uses scrubber data that reflect pre-1995 estimates of the variable cost of scrubbing, but the actual performance of the Phase I scrubbers has been much better than predicted. Correction of this item alone largely

---

[13] MCA provides a bottom-up, plant-by-plant analysis based on reported capital costs and observed sulfur premia. CBCP conducts an econometric estimation of a translog cost function and share equations of unit-level data for 734 *non-scrubbed* units over the 1985-94 period and then takes the resulting parameter values to form marginal abatement cost functions for individual units, which are then used to estimate actual costs based on observed 1995-96 emission levels. Scrubbed units are handled separately on a cost accounting basis using identical cost of capital and depreciation assumptions as in Ellerman *et al.* (2000).

[14] The numbers cited from CBCP are from their break-out of the costs of 2010 compliance. This estimate will be approximately the same as the scrubber costs in 1995-96 since the fixed costs are annualized over 20 years, fuel costs are assumed not to change after 1995, the number of scrubbers is assumed to remain unchanged, and costs are stated in 1995 dollars.

removes the disparity in cost estimates between these two ex post evaluations. As an approximate figure, $750 million is probably a reasonable estimate of the annual cost of abatement in the first years of Phase I.

A simple estimate of Phase II cost can be obtained by extrapolation of this estimate using the increase in the amount abatement observed and the behavior of allowance prices, which can be taken as a reasonable indication of short and long-run costs of abatement. The estimate of $750 million for early Phase I costs corresponds to about 4.0 million tons of abatement, while currently observed abatement is about 6.5 million tons, or 63% more. Although three new retrofitted scrubbers were operating as of 2001, most of the 2.5 million tons of additional abatement since 1995 has occurred through switching to lower sulfur coal. Allowance prices provide a good proxy for the per ton cost of this additional abatement since there is every indication that utilities recognize that allowances are perfect substitutes for abatement at the margin and act accordingly.

After an initial downward adjustment, allowance prices have moved generally upward, as would be predicted for agents engaged in reasonably rational banking programs; and since early 1998, prices have ranged from highs of about $210 to lows of about $130. In addition, the significant observed reduction in scrubber cost has brought the total costs of scrubbing within the upper end of the range of allowance prices since 1998.[15] Hence, it is reasonable to assume that the increment total cost of the additional abatement observed since 1995-96 lies between $150 and $200 a ton. This implies an additional total cost of abatement between $375 million and $500 million (2.5 million tons of additional abatement times $150/ton and $200/ton, respectively) and a total estimated cost for early Phase II abatement of between $1.125 billion and $1.25 billion. Since another 1.5 million tons is to be abated as the Phase I allowance bank is drawn down, total annual costs for compliance with the completely phased-in Phase II limits would be about $1.5 billion assuming an incremental per ton cost of $200.

[15] Ellerman and Joskow (forthcoming) provide a discussion of the evolution of estimates of scrubbing costs and estimates of the cost of scrubbing the remaining unscrubbed coal units. Taylor et al. (2001) also provide estimates of the decline in scrubber costs since the early 1970s.

By any reckoning, these estimated costs, made with the benefit of observed data and trends, are lower than the ex ante predictions when Title IV was enacted. Most of the often noted disparity between ex ante and ex post estimates of the cost of the Acid Rain Program reflects very different assumptions about the nature of proposed acid rain controls, the projected demand for electricity, and the relative availability and cost of low sulfur coal. For instance, the total annual costs associated with some of the early proposals to control acid rain precursor emissions were estimated at amounts ranging from \$3.5 to \$7.5 billion, 2 to 5 times what now appear likely to be the cost of a fully phased-in program. Although the details of these earlier proposals varied, they generally mandated scrubbers at a significant number of units and allowed very limited emissions trading. Once the proposal that ultimately became Title IV was proposed (in 1989) and enacted (in 1990), the ex ante cost estimates for the fully phased-in program with trading fell to a range from \$2.3 billion to \$6.0 billion, with most of this variation reflecting varying assumptions about the extent to which emissions trading would be used.

A good example is provided by the discussion in MCA (pp. 231-235) of the few ex ante estimates of Phase I costs and a comparison with the MCA estimate of actual cost. Most of the variation in the ex ante estimates, made only a few years before Phase I began, reflects differing assumptions about the extent to which utilities made full use of the flexibility afforded by emissions trading. When compared on an average cost basis to account for differences in assumptions about the quantity of abatement (due to differing assumptions about the growth in electricity demand and the extent of banking), MCA's ex post estimate of cost in 1995 was slightly above (3-15%) ex ante estimates assuming full use of emissions trading and 20-35% below estimates that assumed relatively little use of emissions trading.

CBCP provides a very helpful quantification of the causes of the change between the early estimates of fully phased-in Title IV costs and the current estimates. In analyzing the causes for the change between expected costs as of the mid-1980s and actual costs in early Phase I, CBCP find that the marginal cost of abatement for a representative generating unit has been approximately halved and that 80% of the reduction in cost is attributable to falling price of low-sulfur coal relative to the price of high sulfur coal and that the remaining 20% is attributable to technological change. Estimates of fully phased-in Phase II costs are then made using different assumptions about coal prices, technological change, and the use of trading, as illustrated in Table 6.

Table 6: Simulated Total Cost of Compliance with Title IV in 2010
(billion 1995 dollars)

Cost Assumptions	Command-and-Control	Efficient Trading
1989 Prices and Technology	$2.67	$1.90
1995 Prices and Technology	$2.23	$1.51
1995 Prices and 2010 Technology	$1.82	$1.04

Source: Carlson et al. (2000), Table 2, p. 1313

Since efficient trading is being observed, the relevant estimate for Phase II cost from this study lies between $1.04 billion and $1.51 billion, depending upon the amount of technological progress from 1995 to 2010. The estimate of $1.5 billion presented above lies at the upper end of this range, but it does not attempt to estimate further improvements in abatement technology. Even so, this table shows that, while costs depend on prices and technology, which are not subject to program design, the ability to trade, which is subject to program design, can lead to equally and even more significant reductions in the cost of compliance.

In summary, it seems clear that Phase II costs are considerably lower than what was expected and that this difference is attributable to 1) the flexibility allowed by Title IV, 2) improvements in abatement technology, especially in scrubbers, and 3) the lower prices for low sulfur coal due largely to changes independent of Title IV. As detailed in Ellerman and Montero (1998), the most important independent change was the reduction in rail rates that made low sulfur bituminous coals from the West economically attractive as a replacement for high sulfur, Midwestern bituminous coal and significantly reduced the abatement requirements imposed by the Title IV cap.

CONCLUSION

With two years of Phase II compliance data now available (and a third year's data about to be released), more confident answers concerning the effectiveness of cap-and-trade systems can be made. Although not discussed in this paper, nothing suggests that allowance markets are working less efficiently in Phase II than in Phase I; and there is plenty of anecdotal evidence to suggest that the owners of Title IV affected units are avoiding whatever less than optimal abatement choices may have been made in Phase I. The more important evidence arising from Phase II compliance concerns the distribution of total abatement, the efficiency of banking, the extent to which lack of an allowance endowment impedes the entry of new generating units, and not least the total cost of compliance. This evidence provides the basis for the following tentative conclusions.

1. By far, the bulk of the abatement by Title IV affected units is being made by the Phase I units that, by definition, are the larger units with relatively high pre-Title IV emission levels, located mostly in the Midwest. About three-quarters of the reduction in SO_2 emissions due to Title IV is occurring in this region of the country and this share is larger that that region's share of electricity generation or pre-Title IV emissions. This pattern of abatement implies that the cheapest abatement lies where emissions are greatest and that market-based incentives can be expected to direct abatement to these locations.

2. The amount of banking undertaken in Phase I and the rate of draw down in Phase II has been reasonably efficient. The observed response to the sharp discontinuity in marginal cost created by the two phases of Title IV suggests that, when banking is allowed, agents take a longer view and distribute abatement efficiently over time. This behavior also implies a non-mandated acceleration in the timing of the required cumulative abatement that is environmentally beneficial.

3. There is little evidence in Phase II that failing to endow new generating capacity with allowances impedes entry. While a frequently voiced complaint, and perhaps unfair in some non-economic sense, the practical realities are that neither short-run nor long-run marginal calculations concerning production or entry are affected by the allowance endowments in Title IV. Moreover, SO_2 allowance cost

is a relatively minor consideration when compared with permitting and siting costs and new source performance requirements.

4. While detailed studies of Phase II compliance cost have not been performed, reasonable extrapolations from carefully done earlier analyses of Phase I cost continue to indicate that the fully phased in cost of Title IV is and will be significantly lower than expected, somewhere between $1.0 billion, at the very lowest, and perhaps $1.5 billion at the high end. Much of the explanation for the disparity with the much higher ex ante forecasts lies in differing assumptions about the rate of improvement in abatement technology and other changes in the coal sector that are largely independent of Title IV; however, a significant share of the disparity can be attributed to the flexibility provided by Title IV and electric utilities' willingness to take advantage of the cost-saving opportunities provided by emissions trading.

REFERENCES

Burtraw, Dallas 1996. "The SO_2 Emissions Trading Program: Cost Savings without Allowance Trades," *Contemporary Economic Policy*, 14 (April): 79-94.

Carlson, Curtis P., Dallas Burtraw, Maureen Cropper, and Karen Palmer (Carlson *et al*, 2000, abbreviated to CBCP). "SO_2 Control by Electric Utilities: What are the Gains from Trade?" *Journal of Political Economy,* Vol. 108, No. 6: 1292-1326.

Ellerman, A. Denny 2003. "Ex Post Evaluation of Tradable Permits: The U.S. SO_2 Cap-and-Trade Program." MIT-CEEPR Working Paper 2003-003 and forthcoming in OECD *Ex Post Evaluation of Tradable Permit Systems* (working title).

Ellerman, A. Denny and Paul L. Joskow. (forthcoming). "To Retrofit or to Replace: The Economics of Scrubbing and Switching to Natural Gas," MIT-CEEPR Working Paper.

Ellerman, A. Denny and Juan-Pablo Montero. 1998. "The Declining Trend in Sulfur Dioxide Emissions: Implications for Allowance Prices," *Journal of Environmental Economics and Management* 36: 26-45. (This article is substantively reproduced as chapter 4 of Ellerman et al. (2000)

Ellerman, A. Denny and Juan-Pablo Montero. 2002. *The Temporal Efficiency of SO_2 Emissions Trading*, MIT-CEEPR Working Paper 02-003 (September)

Ellerman, A. Denny, David Harrison and Paul L. Joskow. (Ellerman *et al*., 2003). *Emissions Trading: Experience, Lessons, and Considerations for Greenhouse Gases*. Washington, D.C.: Pew Center for Global Climate Change (scheduled for release on May 15, 2003).

Ellerman, A. Denny, Paul L. Joskow, Richard Schmalensee, Juan-Pablo Montero, and Elizabeth Bailey (Ellerman *et al*., 2000; abbreviated to MCA). *Markets for Clean Air: The U.S. Acid Rain Program*. Cambridge University Press, 2000.

Joskow, Paul L., Richard Schmalensee, and Elizabeth M. Bailey (Joskow *et al*., 1998). "The Market for Sulfur Dioxide Emissions," *American Economic Review* 88:4, pp. 669-685. (This article is substantively reproduced as chapter 7 of Ellerman et al. (2000).)

Montero, Juan-Pablo (1999). "Voluntary Compliance with Market-based Environmental Policy: Evidence from the U.S. Acid Rain Program," *Journal of Political Economy*, 107 (October): 998-1033. (This article is substantively reproduced as chapter 8 of Ellerman et al. (2000).)

Popp, David (2001). *Pollution Control Innovations and the Clean Air Act of 1990*, NBER Working Paper 8593. Cambridge, MA: National Bureau of Economic Research (November).

Schennach, Susanne (2000), "The Economics of Pollution Permit Banking in the Context of Title IV of the Clean Air Act Amendments", *Journal of Environmental Economics and Management* 40, 189-210.

Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan-Pablo Montero and Elizabeth Bailey (1998). "An Interim Evaluation of Sulfur Dioxide Emissions Trading," *Journal of Economic Perspectives*, 12(3): 53-68 (summer).

Swift, Byron 2000. "Allowance Trading and SO_2 Hot Spots: Good News from the Acid Rain Program," *Environment Reporter,* 31:19 (May 12), pp. 954-59. Washington, DC: BNA, Inc.

Swift, Byron 2001. "How Environmental Laws Work: An Analysis of the Utility Sector's Response to Regulation of Nitrogen Oxides and Sulfur Dioxide under the Clean Air Act," *Tulane Environmental Law Journal*, 14:309 (summer)

Taylor, Margaret R., Edward S. Rubin, and David A. Hounshell (Taylor *et al*., 2001), "The Effect of Government Actions on Technological Innovation for SO_2 Control," *Proceedings of the EPA/DOE/EPRI/AWMA MegaSymposium, August20-23, 2001*. Pittsburgh, PA: Air & Waste Management Association (October).

May 2, 2003 11:30AM
Question and Discussion Session

Q. Hale Thurston, US EPA, Office of Research and Development:
I am not as familiar with CSI as I would like to be, so I apologize to the experts in the room. A couple of quick questions for Mr. McLean or Dr. Burtraw: Does the CSI default to or propose a specific allocation method? And then, too, is an increase in deci-views an explicit goal of the program?

A. Brian McLean, US EPA, Office of Atmospheric Programs
In response to the first question on the allocation mechanism—yes. In the Clear Skies Act there is a specific allocation mechanism for each of the three emissions (pollutants). I have to call them emissions since someone might bring up the fourth one—the three that we have are all pollutants. The mechanism that is in there is a declining grandfathered system and an increasing auction. It recognizes some of the merits and advantages of an auction system but also recognizes the difficulty of moving abruptly to that kind of system, which is very new. Just wanted to mention to those who deal with this issue, prior to this kind of a program in the U.S., where we don't rely heavily on taxes or fees, all the permits are free and everything we give away is free. When we introduce a concept of paying for this, it's a new concept and a change to the way people operate. It works very well in a market system--naturally you start talking about paying for it, but all our command-and-control structures--people don't pay for that permit--they are given that permit to emit a certain amount. We charge some fees, but they are not comparable to what it would cost to buy that permit. So that's how the mechanism works, and we phase it in—actually it takes over 50 years to phase it in, so it's a very gradual phase in. The present value of those allowances is pretty high in terms of the gift that is still given.

In regard to the second question, the deci-view issue, that's what you are also raising, is tied to visibility. That is a measure of a noticeable change in visibility, and it's a way to describe an impact of the program. There are no visibility goals, just as there are no specific air quality goals and no specific deposition goals. The Clear Skies Initiative does not set air quality standards, visibility standards, or deposition standards—what it does is it controls emissions, and in that way it will contribute to the achievement of all those standards. So the goal of the program or objective is an emission-driven program.