Emissions Trading: ERCs or Allowances

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ABSTRACT

There are two principal choices of the baseline from which emissions trading may take place: 1) emission reduction credits (ERCs) in which the baseline is existing regulations which are often activity-based; and 2) cap-and-trade which specified the total allowable emissions. This paper examines the effects of these two tradable permit systems on marginal and average costs for the firm, using electricity generation as an example. The ERC system subsidises the activity level to which it is tied, failing to incorporate the full cost of external harm into the product price. The cap-and-trade system is more efficient.

JEL classifications: Q25, Q28

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I. Introduction

Interest in the use of emissions trading, often referred to as tradable pollution permits (TPPs), has increased during the last decade, spurred in part by the enactment of an emissions trading program for sulphur dioxide emissions from power plants in Title IV of the 1990 Clean Air Act Amendments in the United States. Further interest has arisen from concerns about greenhouse gas emission control and the belief that TPPs could play an important role in any international agreement to reduce these emissions, evidenced by Article 17 of the 1997 Kyoto Protocol which describes an international trading system for greenhouse gases as one of four cooperative mechanisms to achieve greenhouse gas targets by 2008-12. The Ontario Ministry of the Environment has proposed an emissions trading system for air pollutants in connection with the restructuring of the electricity industry. (Ontario Ministry of the Environment, 2000.)

While there is an extensive literature on emissions trading generally and the costs that may be saved by trading compared to command-and-control regulations (see, e.g., Tietenberg, 1985; Hahn and Hester, 1989; Joskow, Schmalensee and Bailey, 1998), there are some design matters on which there has been little economic analysis. The question addressed here is choosing the baseline from which trades take place, which can be characterized as the use of credits for reducing emissions below the requirement of existing regulations (emission reduction credits or ERCs) or the use of allowances under a cap-and-trade system. A related question, whether trading is limited to a specified set of sources (closed) or whether other sources can enter into trades with the specified set (open) is not addressed.

An ERC is generated by reducing emissions below a regulated amount that is generally defined as an emission rate proportional to an activity level in the polluting plant. An allowance system starts with a desired total emission rate for the industry, usually expressed in tonnes per unit of time and then allocates portions of this total to individual plants. The crucial difference is that with allowances the total allowed pollution emissions for the industry do not vary with current economic activity in the industry while with ERCs emissions may increase in proportion to industrial activity.

This paper explores the impacts of these two designs on the marginal and average cost of production, on the price of TPPs and on emission rates. It uses a stylized electricity generation industry as an example although the results would be equally applicable to any industry burning substantial quantities of fossil fuels. Section II of the paper explains in more detail how ERC and allowance systems work and how they differ, referring to existing pollution regulations in Canada and the United States, and reviewing the relevant theoretical literature. Section III uses a simple model of a competitive industry to explore marginal incentives in the short run, while section IV uses a simulation model to explore a broader range of effects. Section V summarizes the conclusions and policy implications that flow from the analysis.

II. Background

Environmental regulation in both Canada and in the United States has relied on a mix of instruments. Ontario has set limits on the maximum airborne concentration of pollution to which a source may contribute, using these limits in granting certificates of approval to new sources.[1] US legislation sets air quality targets for half a dozen pollutants and requires vigorous state action when an area fails to meet these targets.[2] But in both countries the principal regulation of air pollution consists of maximum emission rates for individual sources. In most cases, these emission rates are tied to the activity level of the polluter. For example, the Canadian federal guidelines for thermal power generation emissions limit the discharge of nitrogen oxides, particulate matter, and sulphur dioxide in grams (actually nanograms) of the pollutant per Joule (ng/J) of heat input.[3] Ontario's *Boilers Regulation* prohibits the burning in boilers of oil or coal with a sulphur content greater than one percent unless the emissions are no greater than if the fuel had contained less than one percent sulphur. Ontario's guidelines for stationary combustion turbines limit nitrogen oxides and sulphur dioxide in proportion to the power output of the turbine.[4] An exception to this rate-based format is the regulation that limits Ontario Hydro to 175 kilotonnes per year of sulphur dioxide discharge, regardless of the location of the generation unit, one of four regulations that formed the core of the Ontario acid rain control program.[5]

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[1] O.Reg. 795/94, Regulation 346 General - Air Pollution, s. 5, Schedule 1.

[2] 42 U.S. Code s. 7408 *et seq.* See Tietenberg (2000, ch. 16) for a discussion.

[3] *Thermal Power Generation Emissions National Guidelines for New Stationary Sources* P.C. 1990-333. The SO2 limit for coal-fired power plants is 258 ng/J (0.6 lbs/mmBTU) or 90 percent removal, whichever is greater.

[4] Ontario Ministry of the Environment, "Guidelines for Emission Limits for Stationary Combustion Turbines" (Toronto, MOE, March, 1994.)

[5] "Ontario Hydro" R.R.O 1990 Reg. 355.

In the United States, the new source performance standards (NSPS) for coal-fired electric power plants first enacted in 1970 limit sulphur dioxide emissions to 520 ng/J, equal to 1.2 pounds of SO2 per million British thermal units of fuel heat input (lbs/mmBtu) with an added requirement that at least 90 percent of the SO2 be removed from the stack gases or 260 ng/J and 70 percent removal. (See Appendix A.) The NSPS for nitrogen oxides limits emissions to a variety of values ranging from 86 ng/J to 340 ng/J depending on fuel type, with the highest limits allocated to coal combustion. (See Appendix B.) Existing US sources that are not subject to the NSPS are regulated by implementation plans (SIPs) designed to achieve the ambient air quality objectives. These state regulations generally limit the amount of pollution that may be discharged per unit of activity by the source, frequently differentiated by fuel type. Appendix C summarizes some such regulations for four Great Lakes states. The majority of the limits are expressed in pounds of sulfur dioxide per mmBtu of coal burned or the fuel sulfur percentage for burning oil. The limits are more stringent where pollution concentrations are higher. In Ohio and Indiana the regulations list emission limits for dozens of specific boilers grouped by county. In some cases, the limits are expressed per ton of product output or per ton of input (e.g. per ton of metal charged in a steel mill); in other cases the emission rate per mmBtu is accompanied by a limit on the heat input to the boiler; and in some cases there is a limit on the total sulfur dioxide emissions per hour for the furnace or facility. The general state limits are much less strict than the NSPS limits.

Three features of these regulations are important. First, the NSPS and the state regulations are generally tied to the activity level of the source, rising or falling with fuel input, power output or product output. In many cases, however, the permit specifies the capacity for the source, setting an upper limit on emissions. Second, the emissions of pre-existing sources are governed, if at all, by state regulations which are frequently less strict than the NSPS. This allows some existing sources to continue polluting at high rates indefinitely while the high cost of complying with the NSPS may delay the construction of new and cleaner sources. For example, the US NSPS for SO2 from utility boilers was first set at 1.2 lbs/mmBtu in 1970, yet a quarter of a century later 263 generating units still emitted more than 2.5 lbs/mmBtu. (Ellerman, *et al*. 1997, p. 12.) Third, there is no reason to expect these regulations to equate the marginal cost of pollution control even at sources that are close together and therefore contributing to a single environmental problem. As a result, they are inherently inefficient, causing costs higher than would be necessary to achieve the same environmental result.

Rigidities in the US system of environmental regulations and their inherent inefficiency generated pressure for flexibility during the 1970s leading to four types of emission trading programs. "Netting," begun in 1974, allows a plant to add a new source (stack or pipe) within the plant without meeting strict NSPS requirements so long as some other source within the plant reduces its emissions by more than the emissions of the new source and subject to the approval of the state. "Offsets" allow the construction of a new pollution source after 1975 in a "non-attainment" area (which would otherwise be prohibited) so long as the new source procures a reduction in emissions from an existing source in the same area that is greater than the new emissions. "Bubbles" allow a plant after 1979 to sum emissions from all sources within the plant and adjust their individual emissions so long as the total plant emissions do not exceed the total allowed emissions for all of the sources. "Banking" allows firms after 1979 to save reductions below the allowed emission amounts and use them for future emissions trading. All four of these trading mechanisms are based on existing regulations and therefore generally have as their base an emission rate that is tied to the activity level of the source.

Significant volumes of trading have arisen under these programs achieving cost savings in the hundreds of millions of dollars, which is large in absolute terms but much less than what theory suggests could be achieved from emissions trading. (Hahn and Hester, 1989a, 1989b.) Some of the shortfall in savings may arise from the strict trading requirements formalized in the EPA's 1986 "Emissions Trading Policy Statement" and the attached "Emissions Trading: Technical Issues Document."[6] This policy requires that emission reductions must be surplus, enforceable, permanent and quantifiable to qualify as ERCs. (Policy Statement, II.A.) A permanent reduction is usually achieved by a change in technology that reduces emissions per unit of activity but it may arise from reduced activity so long as the reduction is made permanent by a revision of the source's permit. (Policy Statement, II.A.3.) This means that a temporary reduction in output arising from reduced demand for the product cannot create ERCs.
There are many limits on trading, the most important of which is that ERCs may not be used to meet or avoid new source performance standards. (Policy Statement, II.B.4.) The result of this policy is that an electric utility could generate ERCs by installing pollution control equipment, permanently changing to a cleaner fuel, or permanently reducing output, including closing down (Technical Issues, I.A.1.c.(2)), but not by temporarily reducing output.

A somewhat different ERC program, Pilot Emission Reduction Trading (PERT), was developed by Ontario Hydro and other industrial, government and environmental representatives.

[6] Federal Register, 51:233, December 4, 1986, pp. 43829-43859.

Under PERT, ERCs can be created by “a specific and identifiable action or undertaking which is not a mere change in activity level, (e.g. due to typical business fluctuations).”[7] The quantity of ERCs created equals the activity level during the “creation period” measured in product output, such as MWh generated, or input, such as fuel consumed, multiplied by the difference between the baseline emission rate and the creation period emission rate. PERT does not require that output reductions must be reflected in a change in the source’s permit. Moreover, it explicitly rejects ERCs arising from shutdown of the source, since creation period activity would be zero.[8] Because there is no requirement that the reduction be permanent, it appears that a temporary shift to cleaner fuel or a temporary increase in abatement effectiveness could generate ERCs under PERT, although not under the EPA Trading Rules. The failure to give credit for plant shutdowns is, of course, inefficient in that it tends to preserve the life of inefficient plants. (Hartman, Bozdogan, and Nadkarni 1979; Koch and Leone, 1979.)

A quite different type of emissions trading program was established in 1990 by Title IV of the *1990 Clean Air Act Amendments*.[9] Title IV mandates a 50 percent reduction, about 10 million tons, in the emissions of sulphur dioxide from coal-fired electric utility boilers with Phase 1 taking effect in 1995 and the full reduction in Phase II in the year 2000. Title IV lists the Phase I and Phase II power plants and the quantity of SO2 allowances each should receive, based on 1985-87 fuel consumption and emission rates of 2.5 lbs/mmBtu for Phase I and 1.2 lbs/mmBtu for Phase II. The plants can trade allowances across the continental USA and can bank them. While Title IV does not repeal previous

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[7] Draft Rules for Emission Reduction Trading in Ontario, 1996, section 2.4.1.

[8] Draft Rules, s. 2.10.

[9] 42 USC s. 7651.

emission limitations, the allocation of allowances is not based on such limitations but rather on activity levels in a three-year reference period that preceded the development of the legislation. By the late 1990s, trading in the allowances created by this program had reached substantial levels, and prices had converged and become relatively stable over time. Analysts have concluding that Title IV trading facilitated the passage of the legislation with its major emission reduction and substantial costs. Trading appears to have saved considerable costs of pollution control, stimulating the development of options that were not fully anticipated at the time the legislation was passed. (Ellerman et al. 1997; Smith, Platt and Ellerman, 1998; Klassen, 1996, ch. 5.)

More recently, the RECLAIM program has used emission trading to control NO_x and SO_x in the Los Angeles Basin. RECLAIM is an allowance-based trading system in which firms are given allowances based on the product of activity levels in 1989-1992 multiplied by emission factors for the current year. (Klier, Mattoon and Prager, 1997.) Before RECLAIM was introduced, legislation had provided for reductions over time in these emission factors, so RECLAIM is a means of reducing the cost of achieving a specified emission reduction over time.

This short history reveals a shift from ERCs to allowances as the basis for allowed emissions under emissions trading programs in the United States. In Canada, there has been little trading activity, but the PERT program is an example of an ERC program (PERT, 1997), and the Ontario Ministry of the Environment electricity proposals combine allowances and ERCs.

Most of the theoretical analysis of the efficiency of emissions trading examines allowance systems like that of Title IV, finding that trading can achieve the same level of economic efficiency as an effluent charge. (Tietenberg, 1985, p. 17; Baumol and Oates, 1988, p. 58, ch. 12.) There are two elements to the efficient solution: all sources (in a mixed environment) face the same price for pollution discharge and therefore equate their marginal costs of abatement, minimizing total abatement costs; and by paying a price for pollution discharge equal to the marginal social cost of pollution damage all sources incorporate that marginal damage into the prices of their products.

There is, however, surprisingly little economic literature examining the choice between these two types of emission trading programs and the most relevant literature does not mention trading at all. Thomas (1980) compares regulatory policies that would achieve a given level of air pollution control including: a limit on annual tonnage of particulate discharge; a limit on the type or quantity of fuel used; and a limit on emissions per unit of fuel consumed. Using data from the US steel industry, Thomas finds that the direct regulation of emissions is less costly than regulating fuel use or emissions per unit of fuel. This supports the general principle that the most efficient regulation is one that directly targets the variable that is the goal of the regulation. Helfand (1991) compares several pollution regulations including limiting emissions directly, limiting emissions per unit of output and limiting emissions per unit of input. She finds that profits are higher when the regulation applies directly to pollution than when it is tied to either inputs or outputs to the production process. While neither of these studies discusses tradable pollution permits, if the units that a polluter is allowed to trade under a TPP system are derived from current activity, then both studies imply that an allowance system should impose lower compliance costs than an ERC system in which allowable emissions are tied to activity levels, either inputs or outputs. Neither paper considers the effect of changing product demand on relative compliance costs.

This paper examines the choice between a TPP design in which the initial distribution of permits is through activity-based regulation (ERC), and a TPP design in which the initial distribution of permits is through the creation of allowances in a fixed quantity whose total will not change with activity levels in the industry. I assume that an ERC system begins with regulations limiting emissions in relation to an activity measure in the industry but allows firms to reduce their emissions below the regulated amount and to sell the resulting tonnes not emitted to other firms. This differs from the EPA system in that temporary emission reductions could produce ERCs. An allowance system specifies the total allowed emissions of the pollutant in tonnes per year and allocates that total to individual sources on some historic basis, but the activity level of the sources does not affect the allocation that they receive. In both cases, I assume that the political process has determined the appropriate emission rate and that it is intended to be the same regardless of the system chosen. I will use SO2 emissions from thermal electricity generation plants as an example since this is the subject of the US *CAAA* Title IV and is being considered in Ontario today as a possible form of emission regulation for the competitive electricity industry that is scheduled to emerge in the year 2000. (MDC, 1998, ch 5, RM 5-1; OMOE, 2000.)

This choice has at least two important implications. One, which has been discussed in the literature, is that an ERC system creates uncertainty about the resulting level of environmental quality which will depend on activity levels in the industry. (Tietenberg, 1998, 14.) A growing economy, the creation of new firms, or the growth of old firms will lead to increased emissions over time. Indeed, an ERC system, by itself, does not protect the environment; it just lowers costs of complying with existing activity-based regulations. By contrast, an allowance system sets a cap on total emissions which does not increase with economic growth; the industry will have to use more effective pollution control methods if it is to grow while under an allowance cap. An allowance system can be used, as was Title

IV of the 1990 *Clean Air Act Amendments*, to reduce total emissions. The second implication is that under an ERC system, the firm's behaviour influences the quantity of pollution that it and the regulated industry as a whole may emit, while there is no such effect under an allowance system. It is this implication that will be discussed here. This model differs from the previous literature (Thomas, 1980; Helfand, 1991) in focussing explicitly on efficiency, by setting the model in a TPP framework rather than a regulatory framework, by explicitly treating the cost of pollution control, by determining the marginal cost of pollution abatement and by determining the market price of emission permits under each policy.

III. Short-Run Analysis

Assume a competitive industry consisting of ten identical firms each of which has a generation plant with boilers burning coal or natural gas and emitting air pollution from the coal. In the short run, the industry is obliged to generate enough electricity to meet the demand, so short run industry demand is perfectly inelastic at 1000 MWh in the base case. Each boiler can burn high sulphur coal, low sulphur coal, natural gas, or a blend of these fuels, emitting sulphur dioxide (SO2) when coal is burned. Reductions in SO2 emissions can be achieved by using pollution control technology to reduce the emissions of sulphur dioxide subject to increasing marginal costs, or by switching to a lower-sulphur fuel. While the pollution control strategies of a real-world utility are more complex, involving boilers with different operating costs and utilization rates and the installation of different controls on different boilers, this simple model captures the principal behavioural elements that would arise from the policies being considered here.

Assume that the Ministry is considering imposing one of two TPP systems for controlling SO2 emissions. The first system is an ERC system in which the Ministry limits emissions from coal-fired plants to ? tonnes of SO2 per tonne of coal burned. Any coal-fired plant that emits less than the limit creates ERCs for the difference and may use those ERCs in the future or sell them to other plants. All such sales must be registered with the Ministry. Gas-fired plants do not generate ERCs, a simplification from the limits shown in Appendix A and Appendix C, some of which have a non-trivial emission limit for SO2 from a gas-fired source. This TPP model is consistent with the US EPA's 1986 Emissions Trading Policy as indicated below for an industry of identical plants.

The second system is a cap-and-trade or allowance system in which the Ministry determines the total annual emissions of SO2 in tonnes and allocates allowances to each plant in proportion to its coal consumption in a specific past year. The total allowed emissions are the same as they would be in the ERC case with the base demand scenario (1000MWh) and only coal used as fuel. Plants may trade allowances, but must register all trades with the Ministry. No plant may emit SO2 in excess of unused allowances that it holds and one allowance must be surrendered for every tonne emitted.

In the short run, the only variable costs are fuel costs, abatement costs, and costs for ERCs or allowances. The marginal cost function for a plant, not counting pollution abatement, is constant up to the capacity of the plant and infinite at that point. We assume that the plant's permit allows it to emit at the specified rate per unit of fuel burned up to the specified capacity of the plant. While the supply of ERCs or allowances is fixed for the industry, in a competitive industry the supply for any firm is elastic, so we assume that the firm may buy or sell ERCs or allowances at a fixed price.

The amount of electricity generated by a plant in a specific period of time is determined by the fuel consumed and the efficiency of the plant in converting fuel into electricity:

$$MWh = \alpha_h T_h + \alpha_l T_l + \alpha_g T_g \quad i.e. \ = \sum \alpha_f T_f \tag{1}$$

where α_f = electricity generated in megawatt hours (MWh) per unit of fuel burned and

T_h = tonnes of high sulphur coal burned

T_l = tonnes of low sulphur coal burned

T_g = tonnes (equivalent) of gas burned

Pollution emissions EM are also a function of the sulphur content of the fuel β_i (tonnes of sulphur per tonne of fuel), the quantity of fuel consumed, and the percentage of pollution A removed by control technology:

$$EM = (\beta_h T_h + \beta_l T_l)(1 - \frac{A}{100}) \tag{2}$$

Natural gas burning does not release any SO2. Since the two types of coal may be blended the pollution discharged can be represented by:

$$EM = \beta_c T_c (\frac{100 - A}{100}) \tag{3}$$

where $T_c = T_h + T_l$ and $\beta_c = \frac{T_h \beta_h + T_l \beta_l}{T_h + T_l}$

The total cost of pollution control should increase with the amount of coal burned, the fuel sulphur content, and the percentage of emissions that are controlled. (Reinert and Ratick, 1988.) For specificity, we assume a particular form of the control cost function that is consistent with the observed shape:

$$CCTL = T_c H (0.2 + \beta_c) \frac{A}{(100 - A)} \tag{4}$$

where T_c is the total tonnes of coal burned, H is a constant in dollars per tonne of pollution emitted, $ß_c$ is the average sulphur content of the coal, and A is the percentage of pollution that is removed by the control technology. With coal sulphur content ranging from 1 percent to 5 percent, $ß_c$ could range from 0.01 to 0.05.

While each firm has an initial distribution of allowable emissions or can create them by burning coal, these can be sold in the market so they have an opportunity cost equal to their market price. For a system of ERC's, the short run cost of electricity generation is the cost of fuel plus the cost of emission control, plus the opportunity cost of ERCs:

$$CST = \sum T_f P_f + T_c H(0.2 + ß_c)\frac{A}{100-A} + T_c\left(ß_c \frac{(100-A)}{100} - ?\right)P_m \tag{5}$$

where: P_f is the price per unit of fuel f and P_m is the price of ERCs.

For an allowance system, the short run cost involves the same elements as above except that the cost of allowances replaces the cost of ERCs:

$$CST = \sum T_f P_f + T_c H(0.2 + ß_c)\frac{A}{100-A} + \left(T_c ß_c \frac{(100-A)}{100} - ?\,T\,(\,)\right)P_m \tag{6}$$

where ? T* is the quantity of allowances allocated to the firm for this period.

Because the firms are identical, we can assume that they will behave identically. With inelastic industry demand for the specified hour of 1000 MW, each firm will generate 100 MW. Under an ERC system, each firm can emit ? times T_c the tonnes of coal burned; under an allowance system each firm can emit ? times T*= 100/a_c, the number of tonnes of coal that would be burned if the firm burned only coal. The firm's task is to minimize its costs, according to equation 5 or 6 subject to generating 100 MW and not exceeding its emission constraint. Assume that $P_h<P_l<P_g$ so that the firm would prefer to burn the dirtier fuel until the emission constraint forces it to move to the more expensive fuel. The firm's

strategy can be seen by exploring what would happen as ? decreases from a high level to zero. With ? >ß_h the firm will burn high sulphur coal with no controls. As ? is reduced, the firm will begin to use abatement equipment, increasing the degree of abatement until it is cheaper to mix in some low sulphur fuel with the high sulphur fuel. As ? is further reduced the amount of high sulphur fuel is reduced to zero and the degree of abatement will be increased until it is cheaper to burn natural gas, whereupon coal will be phased out.

While the firm's overall problem is not subject to analytical solution, we can find analytic solutions to the problem when a particular fuel is used. For example, we examine the case where the firm is burning high sulphur coal but is forced to use some pollution abatement. The general problem is to minimize the cost of generation subject to generating the 100 MWh.

1. ERCs

To solve this minimization problem for ERCs, form a Lagrangian from Equation 5:

$$L \,'\, T_h P_h \% T_h H(0.2\%\text{ß}_h)\frac{A}{100\&A}\% T_h(\text{ß}_h\frac{(100\&A)}{100}\&?)P_m \% ?(a_h T_h \& 100) \qquad (7)$$

Differentiating with respect to the quantity of fuel yields the first order condition:

$$P_h \% H(0.2\%\text{ß}_h)\frac{A}{100\&A}\%(\text{ß}_h\frac{(100\&A)}{100}\&?)P_m \% ?a_h \,'\, 0$$

$$\&? \,'\, \frac{P_h}{a_h}\%\frac{H(0.2\%\text{ß}_h)}{a_h}\frac{A}{100\&A}\%\frac{\text{ß}_h(100\&A)P_m}{a_h 100}\&\frac{?P_m}{a_h} \qquad (8)$$

Here ? is the marginal cost of producing electricity using the specified fuel. P_h/a_h represents the cost of the added fuel, the second term represents the cost of treating the additional volume of stack gas in the pollution control process at a constant degree of control A, the third term represents the added cost of purchasing ERCs and the last term represents the value of additional ERCs created by burning additional coal. The last term shows that coal consumption is subsidized relative to gas consumption, since it brings with it the right to discharge increased air pollution. If ? is large, the subsidy may be considerable; as ? approaches zero, so does the value of the subsidy.

In this industry of identical firms, all will abate equally so no ERCs will in fact be bought or sold and firm's emissions will equal its coal consumption multiplied by ? $EM = T_c ?$, which will determine its degree of abatement A. From equation 3:

$$A = 100\frac{\beta_c T_c - EM}{\beta_c T_c} = 100\frac{\beta_c - ?}{\beta_c} \qquad (9)$$

For the industry, the price of ERCs is endogenous, determined by supply and demand. For the firm to minimize cost, the price must be such that the price of one tonne of ERC is equal to the marginal cost of reducing emissions by one tonne at a fixed activity level. Inserting equation 9 in equation 4 yields:

$$CCTL = T_h H(0.2 + \beta_h)\frac{(\beta_h T_h - EM)}{EM} \qquad (10)$$

The derivative of this equation with respect to EM is the marginal cost of control per tonne of emissions, which will equal the price of ERCs:

$$P_m = \beta_h H(0.2 + \beta_h)\left(\frac{T_h}{EM}\right)^2 \qquad (11)$$

Suppose that the demand for electricity increases or decreases. Once the firm has found the degree of emission control A that minimizes its costs of control plus purchasing or selling ERCs, changes in output involve changes in coal consumption which bring with them changes in allowable emissions. The degree of control A will not vary with output; instead emissions will be directly proportional to output. The marginal cost of generation, equation (8), does not include fuel consumption or electricity production as an argument, so the degree of abatement and the fuel mix will not vary as output changes. Marginal and average costs of production will not change with output because of the assumption of constant returns to scale in generation. On the other hand, if ? should decrease (increase), that will require increases (decreases) in the degree of abatement from all firms and thus increases (decreases) in the marginal and average cost of generation. Emissions will vary with output.

How would this analysis differ if the EPA or PERT trading rules were applied? Assume that each plant's permit specifies a capacity sufficient to supply the high demand case (+25%), and allows emissions of ? tonnes of sulphur dioxide per tonne of coal burned up to the plant's capacity. Under the EPA rules, a temporary switch to low-sulphur coal or a temporary increase in the degree of pollution abatement that reduced the emission rate below ? would not generate ERCs so these actions would not lead to trading; each plant would have no incentive to emit less than ? . Indeed, since our cost function is linear in fuel consumption, variations in output arising from changing demand will not lead to any change in abatement or fuel mix. A temporary switch to gas would also generate no ERCs, but this generates no ERCs in our model because ERCs depend on coal consumption, so this does not alter our results. Thus the first order conditions and Table 1 apply equally under the EPA rules.

Under PERT a temporary increase in abatement or a temporary switch to natural gas that reduced the emission rate below the baseline rate could create ERCs. Again, however, since our cost function is linear in total fuel use, changing output levels does not change the desired mix of fuel or degree of abatement.

How would the analysis differ if the baseline emission regulation was based on total fuel use, not coal use, so that temporary switching to natural gas could generate ERCs? In this case, equation 5 becomes:

$$CST = \sum T_f P_f + T_c H(0.2+\beta_c)\frac{A}{100-A} + T_f\left(\frac{T_c}{T_f}\beta_c\frac{(100-A)}{100} - ?\right)P_m \tag{5a}$$

This equation is still linear in total fuel consumption, so there is still no reason to change the fuel mix in response to changes in output level. The first order conditions for any particular fuel use will thus not change from the basic model. However when the allowed emission rate is reduced, a blend of natural gas and coal can be burned; since ? is multiplied by T_f not T_c, substituting gas for coal does not reduce the allowable emissions. Thus blending coal and natural gas could be part of a least-cost emission control strategy when ? is low enough to make gas competitive with further abatement of coal. Since blending will only occur when it is less costly than burning coal alone and applying abatement technology, tying emissions to total fuel use rather than to one fuel will yield lower costs over the range of ? where blending would occur.

2. Allowances

When the TPP system employs emission allowances, there is a fixed allocation (? T*) to the firm regardless of its coal consumption. In this case, remembering that this example assumes the burning of high sulphur coal, the Lagrangian from equation 6 is:

$$L = T_h P_h + T_h H(0.2+\beta_h)\frac{A}{100-A} + \left(T_h\beta_h\frac{(100-A)}{100} - ?\,T(\ )\right)P_m + ?(a_h T_h - 100) \tag{12}$$

Differentiating with respect to the quantity of fuel yields the first order conditions:

$$P_h + H(0.2+\beta_h)\frac{A}{100-A} + \left(\beta_h\frac{(100-A)}{100}\right)P_m + ?a_h = 0$$

so, $$\&?\,'\,\frac{P_h}{a_h}\%\frac{H(0.2\%\text{ß}_h)}{a_h}\frac{A}{100\&A}\%\frac{\text{ß}_h(100\&A)P_m}{a_h 100} \tag{13}$$

The first three terms in equation 13 are identical to those in equation 8 for ERCs. Equation 13 differs from 8 in omitting the fourth term of equation 8 which subtracts the value of ERCs created by burning more coal. Under an allowance system, the marginal cost must include the price of allowances multiplied by the increase in pollution associated with an increase in output at a given degree of pollution control with no offset for increased ERC creation. Thus the marginal cost of increased output must be greater for allowances than for ERCs, because for the industry as a whole more output cannot increase emissions while with ERCs more output increases emissions so long as more coal is burned.

As with the ERCs, in this industry of identical firms, all will abate equally so if allowances are distributed equally, no allowances will in fact be bought or sold. If the total allowances are set to equal the total emissions under the ERC system with the same level of electricity demand, each firm's allowances ? T* will equal 1/10 of the industry emissions. Suppose that the demand for electricity increases (decreases), increasing (decreasing) the output of the industry and the representative firm. With allowances, total emissions cannot increase and they will not be reduced unless the value has dropped to zero, so the increased (decreased) demand will be met by increasing (decreasing) the degree of pollution control. The marginal cost of output is greater with allowances than with ERCs.

If the pollution limit has been set optimally, P_m equals the marginal harm from one unit of emissions and the third term in equation 13 represents the external cost of the harm arising from increased output. Thus the firm faces the full marginal cost of external harm under the allowance system. Since the third term is offset by the fourth term under the ERC system the firm does not face this full external cost with ERCs. In short, ERCs that are based on the activity level of the firm subsidize additional production, reducing the price of the product as compared to a system that levied a Pigouvian tax. This is the central distinction between the two systems.

IV. Simulation Analysis

Assume that the emission limit ? for the ERC system is set at 0.021 tonnes/tonne of coal burned, just greater than the uncontrolled emission rate for low sulphur coal. The quantity of allowances is set to permit the total amount of pollution that would arise from burning coal at current demand levels, which require 1000 MWh of generation during the specific hour in question, and emitting at the allowed rate ? . This means that the marginal electricity cost equations for the firms remain as set out in equations 8 and 13 but that the price of TPPs must now be endogenous, to be determined by supply and demand within this industry. We assume that this industry is small relative to the total supply of fuel so that the three fuel prices remain exogenous.

The firms will choose output levels such that their marginal cost of generation MCL is just equal to the market price for electricity. Because fuel prices are fixed and each firm has constant costs up to its capacity, firm output is indeterminate but industry output and price will be determined by industry supply and demand. The price of electricity is now endogenous.

We assume a base demand for electricity of 1000 MWh. However in an electrical system that includes nuclear and hydroelectric sources, the demand for fossil energy can vary substantially depending on weather (and therefore water flow) and on the performance and the availability of the nuclear plants. For example, 1998 was a dry year in Ontario and water flows were low at the same time that seven nuclear plants were closed down to deal with serious operating problems. As a result, coal consumption for generation in Ontario was almost twice as great in 1998 as it had been in 1997. We therefore consider two alternative cases: one with a 25 percent reduction in demand and one with a 25 percent increase in demand above the baseline. Finally, because we have chosen an emission limit for the ERC system that is just greater than the emission rate for low sulphur coal, we will also examine a case in which ? is 0.019, marginally below the emission rate for low sulphur coal.

[table 1 about here]

Table 1 presents the base demand scenario and several variations, assuming that the price of gas is $70 per tonne of coal equivalent, the low sulphur coal price is $60/t and the high sulphur coal price is $50/t. In the base scenario with ERCs all generators would prefer to burn cheap high sulphur coal but they minimize cost by burning a blend of mostly high sulphur coal and some low sulphur coal, scrubbing the resulting stack gases extensively. Figure 1 shows the fuel mix with ERCs. The marginal cost of fuel plus control is $19.54 per MWh reflecting the blended fuel cost and there is no need to purchase ERCs so this is the marginal generation cost. The price of ERCs from Equation 11 is $302. Emissions are constrained by the regulation to 0.7 tonnes per firm, or 7 tonnes for the industry. If demand drops by 25 percent, then coal burning drops by the same amount and allowable emissions are similarly reduced. If demand increases, allowable emissions increase in proportion. The marginal cost of generation and the price of ERCs is unchanged by these variations in output since allowable emissions vary with coal consumption.

[Figure 1 about here]

The fourth case in Table 1 assumes that ? is 0.019, slightly less than the low sulphur coal emission rate. This increases the proportion of low sulphur coal relative to high sulphur coal, raising the marginal electricity cost to $19.98. With ? =0.019, P_m rises to $314/t. Equation 11 suggests that as EM is reduced P_m would rise rapidly, but in fact the price of ERCs is capped by the availability of natural gas which requires no ERCs. Figure 1 shows that as ? is reduced from 0.05, high sulphur coal is burned, with increasing use of abatement technology until at about 0.022 there is a rapid substitution of low sulphur for high sulphur coal. Below 0.016 only low sulphur coal is burned and abatement again increases until ? reaches about 0.007 when coal is abandoned for gas. Because ERCs are earned only by burning coal, reducing coal consumption is not a means for achieving emission rate ? ; if it is cheaper to substitute any gas for coal, it is cheaper to abandon coal entirely for gas. Thus as ? is reduced, firms cling to coal consumption until gas is less costly, at which point there is an abrupt shift from all coal to all gas. Figure 2 shows the marginal and average cost of electricity rising as ? is reduced until 0.007 when gas is substituted for coal and both marginal and average cost become constant.

[figure 2 about here]

How would these results change if the ERCs were based on total fuel use rather than on coal use? None of the entries in the table would be altered since all of them reflect the consumption only of coal. However the abrupt shift from coal to gas as ? drops below about 0.07 in Figure 1 would be replaced by a smooth transition, since substituting gas for coal would not reduce the creation of ERCs. Fuel use would be as in Figure 3 for allowances. As a result, the MC/AC curve for ERCs in Figure 2 would change shape - the lump would disappear and the MC/AC curve would be identical to the AC curve for allowances.

The results for the allowance system are rather different. The base case yields the same emissions, 7 tonnes for the industry, and the same price of allowances, derived from equation 11.

However the marginal cost of electricity is $21.66, about 10 percent greater than that for an ERC system. The reason is that to increase output a firm must either buy more allowances, increase its pollution control, or reduce its high sulphur coal consumption to accommodate the increased emissions arising from burning more low sulphur coal. The marginal generation cost is greater than the average cost because abatement is an increasing cost function. Figure 2 shows that the marginal cost of electricity under an allowance system is greater than the average cost of electricity and greater than the marginal and average cost under an ERC system at all levels of ? . If demand falls by 25 percent, then the proportion of high sulphur coal can be increased, reducing average cost to $18.30, but at the margin an increase in output still requires reducing high sulphur coal consumption or purchasing allowances, so the marginal cost of electricity is still above average cost and above the marginal cost in the ERC case. The price of allowances is much less than in the base case because much less abatement is needed. With allowances, emissions do not drop with reductions in output, instead more dirty fuel is consumed and/or less abatement is undertaken. If demand increases by 25 percent, emissions remain the same but more low sulphur coal must be used for the increased output, and more scrubbing is required, raising the electricity price to $22.19 and raising the allowance price to $329, derived from equation 11. The average cost of electricity also rises. Similarly a slight reduction in allowable emissions from the base case raises marginal costs, average costs and P_m.

Figure 3 shows the fuel mix with allowances as the emission limit ? varies. Figure 3 looks like Figure 1 for ERCs down to about ? = 0.015, below which there is a smooth substitution of gas for coal with allowances. This is quite different from the ERC system which preserves the use of coal down to ? of about 0.007 at which point coal is suddenly abandoned.

In summary, the ERC systems and allowance systems differ in several important respects. The ERC system allows the generators to expand output without changing their fuel mix, so the marginal and average cost of generation and the price of TPPs are affected only by the marginal fuel cost which is constant. Emissions rise and fall with demand. With allowances, emissions do **not** vary with industry output unless output is so low that the price of allowances falls to zero, but the marginal cost of electricity, the average cost of electricity, and the price of allowances all rise and fall with output. Moreover the marginal cost of electricity is greater with allowances than with ERCs which more fully reflects the external costs imposed by these emissions.

Since increased output does not require the purchase of additional ERCs, the MCL in Table 2 does not include ERC costs. With P_m equal to \$302, and assuming that this reflects the marginal social harm from increased emissions, MCL should be increased by \$302 times the number of tonnes of emissions associated with one MWh increase in electricity output, or \$2.11/MWh. That would yield an MCL of \$21.65, which is exactly the MCL under the allowance system. In short, the ERC system, while it is an emissions trading system, does not incorporate the marginal social cost of pollution into the product price. The allowance system does.

Our simulations, based on hypothetical data, suggest that the ERC system could cause the marginal product cost and therefore price to be 10 percent less than the efficient price set under the allowance system. More generally, the inefficient price drop caused by ERCs is proportional to the fraction of the increase in emissions associated with one marginal unit of output that is covered by the allowed emission rate ? , i.e. (ß - ?)/ß, in the absence of emission controls. If ? > ß, then the firm is a net seller of ERCs, so its marginal cost is **reduced** below the marginal cost in the absence of pollution regulation by the ERC system. If ? << ß, then the firm under ERCs must buy almost as many as a firm under allowances to cover one unit of increased output, so the marginal cost of output is barely lower under ERCs than allowances. Montero and Ellerman (1998, Table 3) provide an example of firms burning coal with sulphur dioxide levels of 2, 4 and 6 pounds per mmBtu of heat input, with allowances priced at $150 per ton of SO2, and with endogenous coal prices so that all firms have identical marginal electricity costs including purchasing allowances. In all three cases, the allowance system raises costs by 30% above the uncontrolled case. We can use the data in their example to estimate the implications of an ERC system, assuming (heroically) that the price of ERCs and allowances is exogenously set at $150/ton. If ? = 2.5 lbs/mmBtu, the Phase I limit under Title IV, the plant burning 4 pound coal would need to buy (4-2.5=) 1.5 pounds of ERCs per mmBtu, increasing its marginal costs by 11% over the uncontrolled case, compared to 30% for allowances. The plant burning 6 pound coal would need to buy (6-2.5=) 3.5 pounds of ERCs per mmBtu, increasing its marginal cost by 17% over the uncontrolled case, compared to 30% for allowances. The plant burning 2 pound coal would need to buy emission reduction credits of (2-2.5=) -0.5 pounds, that is, it could sell 0.5 pounds of ERCs per mmBtu, **reducing** its marginal cost by 2.5% compared to the uncontrolled case. Thus their model, which incorporate assumptions different from ours, may be used to support the proposition that the difference between marginal product cost under an allowance system and an ERC system may be significant.

V. Conclusions

The simple model and assumptions employed here produce some clear differences between two forms of TPP design: the use of ERCs and the use of allowances as the basis for trading.

1. The marginal cost of product output under an allowance system incorporates the marginal social harm from production and in a competitive market yields the economically efficient price for the product. The marginal cost of the product is below the efficient price with ERCs even when they achieve the same environmental result as the allowance system. Thus while the theoretical literature asserts that TPPs can achieve the same efficient result as effluent charges, this is not true for TPPs based on ERCs with respect to incorporating the external social cost of pollution into the price of the product.

2. The marginal cost and average cost of product output increase and decrease with output in an allowance system, while they are invariant with output in an ERC system. To the extent that marginal damage increases with emissions, the ERC system fails to reflect the changes in social cost that are associated with changes in emission rates.

3. An ERC system provides no incentive to reduce product output temporarily, despite the harm caused by emissions, while an allowance system provides a continuing incentive to reduce emissions by any efficient means, including reducing product output.

4. Emissions vary with output in an ERC system while they are invariant in an allowance system. The welfare implications of this difference depend on the relative slopes of the marginal cost and marginal benefit functions, as discussed by Weitzman (1974) and Baumol and Oates (1988, Ch. 5).

5. An ERC system in which the ERCs are based on the consumption of a particular fuel, such as coal, implicitly subsidizes coal consumption and thereby discourages switching to cleaner fuels, such as

natural gas. As emission rates are lowered, there will be a range in which firms will cling to coal consumption with increasing costs for stack gas cleaning, rather than following a lower cost path of substituting increasing quantities of cleaner fuel. In contrast, an ERC system in which the ERCs are based on total fuel use or product output will allow the use of blended fuels where appropriate, reducing resource costs compared to the case where ERCs are tied to one fuel. ERCs based on total fuel or on output will yield lower emissions over part of this range, where coal-based ERCs would lead to exclusive coal use, and higher emissions over another part of the range, where only gas would have been burned.

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Table 1
Short Run Industry Costs and Emissions

	ERC					Allowances				
Case	Marginal fuel	MCL $/MWh	ACL $/MWh	P_m $/tonne	Emiss (tonnes)	Marginal fuel	MCL $/MWh	ACL $/MWh	P_m $/tonne	Emiss (tonnes)
base dem	HS	19.54	19.54	302	7.00	HS	21.66	19.54	302	7.00
dem - 25%	HS	19.54	19.54	302	5.25	HS	20.40	18.30	225	7.00
dem + 25%	HS	19.54	19.54	302	8.75	HS/LS	22.19	20.35	329	7.00
? =.019	HS/LS	19.98	19.98	314	6.33	HS/LS	21.97	19.98	314	6.33

Parameter values:

$a_h = a_l$ = 3 MWh/tonne

a_g = 100 MWh/bcf = 3 MWh/tonne equivalent

? = 0.021 tonnes/tonne (2.1 % fuel sulphur content)

$ß_l$ = 0.02 tonnes/tonne; $ß_h$ = 0.050 tonnes/tonne

P_m = $200/tonne

Base electricity demand = 1000 MWh

Total allowances = 7 tonnes.

Fuel prices: P_h = $50; P_l = $60; P_g = $70

LS = low sulphur coal

HS = high sulphur coal

Appendix A
US NSPS for Sulfur Dioxide

Fuel	Limit		Required Removal	Statutory Section
	ng/Joule	lbs/mmBtu	%	40CFR60.43a
Solid or solid-derived	520	1.2	90	(a)(1)
	260	0.6	70	(a)(2)
Liquid or gaseous	340	0.8	90	(b)(1)
	86	0.2	0	(b)(2)

Source: 40CFR60.43a; Title 40 – Protection of the Environment, Chapter I – Environmental Protection Agency, Part 60 – Standards of performance for New Stationary Sources, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, Sec. 60.43a Standard for sulfur dioxide.

Note: The source can avoid the higher concentration reduction requirement by meeting the more stringent mass/energy limit.

Appendix B
US NSPS for Nitrogen Oxides

Fuel	Limit (mass/heat input)		Required Reduction of Potential Combustion Concentration
	ng/Joule	lbs/mmBtu	%
Gaseous fuels	86	0.2	25
Liquid fuels - shale oil	210	0.5	30
Liquid fuels - other	130	0.3	30
Solid fuels			
Anthracite coal	260	0.6	65
Bituminous coal	260	0.6	65
Sub-bituminous coal	210	0.5	65
Coal-derived fuels (Gas, oil, etc.)	210	0.5	65
>25% lignite mined in ND, SD, MT	340	0.8	65
Other solid fuels	260	0.6	65

Source: 40CFR60.44a: Title 40 – Protection of the Environment, Chapter I – Environmental Protection Agency, Part 60 – Standards of performance for New Stationary Sources, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, Sec. 60.44a Standard for nitrogen oxides.

Appendix C

Selected State SO2 Emission Limits

Location, application	Fuel, size	Limit (lbs/mmBtu)	Reference
Pennsylvania			
General	oil	2.8%	123.22(a)(2)
	coal	4	123.22(a)(1)
Allegheny County	all fuels, small	1	123.22(d)(1)
	all fuels, large	0.6	123.22(d)(3)
Southeastern Pa., general	all, small	1.0 inner area 1.2 outer area	123.22(e)(1)
	all, large	0.6 inner area 1.2 outer area	123.22(e)(1)
New York			
General new after 1973	oil	0.75%	225-1.2(a)(1)
	coal	0.6	225-1.2(a)(1)
NYC area	coal	0.2	225-1.2(d)
Suffolk County	coal	0.6	225-1.2(d)
Buffalo area	coal	1.7	225-1.2(d)
Elsewhere	coal	2.5	225-1.2(d)
Ohio			
Cuyahoga County	coal (steam gen)	4	
	all, (specific boilers)	0.0 to 4.9 lbs/mmBtu*	
Indiana			
General	oil	1.6%	326 IAC 7-1.1-2
	coal	6	326 IAC 7-1.1-2

* The Cuyahoga County regulations include widely varying boiler-specific limits in lbs/mmBtu, some limits in terms of lbs/ton of product output or lbs/ton of product input, some limits on the heat input to boilers, and some limits on total lbs of sulfur dioxide emitted per hour for a source.