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Eric Harkness

College Scholars Project

CO_2 Shadow Prices in the U.S. Electric Utility Industry:

Calculating the Costs of Reducing CO_2 Emissions

Presented to a faculty committee at the University of Tennessee on

May 8, 2006

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Presented to:

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Section 1. Introduction

Economists have written extensively about market approaches to environmental externalities including emissions taxes and permit trading programs. Coase (1960), Dales (1968), Montgomery (1972), Tietenberg (1985), and Baumol and Oates (1988), for instance, provide arguments for such approaches. Relative to rigid regulatory approaches such as technology mandates, market approaches allow individual firms to determine their own abatement strategies. When marginal abatement costs vary across firms, the flexibility of a permit trading program leads to cost savings over technology mandates. Moreover, in principle, permit trading minimizes the total abatement cost of achieving a specified emissions target. A permit trading program has the added bonus of prompting new competition among previously independent abatement technology industries resulting in subsequent reductions in abatement costs (Rezek and Blair, 2005).[1]

The promise of achieving low cost greenhouse gas abatement has brought the concept of carbon dioxide (CO_2) permit trading to the forefront of international discussions on climate change. Recent proposals for greenhouse gas allowance trading programs include those in Europe, a small number of U.S. states, and voluntary corporate programs. The perceived success of the U.S. market for sulfur dioxide (SO_2) and nitrogen oxide (NOx) in the electric utility industry, established under Title IV of the 1990 Clean Air Act Amendments, has both motivated and heavily influenced the design of proposed CO2 trading programs.

To be sure, climate change is a real concern of the international community. The Kyoto Protocol serves as the key international policy instrument to reduce greenhouse gases. Under the agreement, which was negotiated in December 1997 and became

[1] For more on the economics of permit trading, please see Section 2 A.

effective on February 16, 2005 following ratification by Russia in November 2004, collective emissions are to be reduced to 5.2 percent below 1990 levels between 2008 and 2012. Country-specific targets range from 8 percent in the European Union and 7 percent in the U.S. to 0 percent in Russia. If greenhouse gas emissions increase or reductions fail to meet targets, countries may participate in a permit trading market. In all, 163 countries have ratified the protocol, though notable exceptions include the U.S. and Australia. In addition to the Kyoto Protocol, in June 2005 the science academies of 11 countries, including the U.S., Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, and the United Kingdom, issued a joint statement on global climate change. The statement warns that climate change is real and that human activity is the driving force behind recent changes in the Earth's climate (EIA 2005).

Carbon is an element commonly found in vast quantities in the atmosphere, soil, carbonate rocks such as limestone, and dissolved ocean water. Records from Antarctic ice cores reveal that the "carbon cycle" has been imbalanced for some 200 years, with a surplus of carbon accumulating in the atmosphere faster than the natural environment can sequester it. The Intergovernmental Panel on Climate Change estimates that before 1750 atmospheric carbon concentration rested at 280 ± 10 parts per million. Today concentration levels are at 374.9 parts per million (IPCC 2001).

The U.S. Energy Information Agency (EIA) estimates that U.S. energy-related carbon dioxide emissions in 2002 totaled 5,746 million metric tons (MMT), or about 24 percent of the world total. In 2000 the U.S. Environmental Protection Agency (EPA) estimates that energy-related activities accounted for 85 percent of U.S. total anthropogenic greenhouse gas emissions on a carbon equivalent basis, and was

specifically responsible for 97 percent of CO2 emissions (EPA 2002). Moreover, the EPA found that electric utility industry fossil fuel combustion accounted for 39 percent of national anthropogenic CO_2 emissions in 2000, consuming 34 percent of U.S. energy from fossil fuels and making the electric utility industry the largest economic sector producing CO_2 emissions (EPA 2001, 2005). In addition, the EPA reports that CO_2 from fossil fuel combustion accounted for a nearly constant 79 percent of global warming potential (GWP) weighted emissions from 1990 to 2000, making it the single largest source of U.S. greenhouse gas emissions. Overall, approximately 85 percent of energy consumed in the U.S. is produced from fossil fuels (EPA 2001).

Given that the electric utility industry is responsible for the largest portion of domestic greenhouse gas emissions, that CO_2 represents a dominant share of these emissions, and that economic theory suggests a tradable permit approach minimizes aggregate abatement costs, a national CO_2 tradable permit market for emissions from electric utility plants offers a legitimate policy option for curbing carbon emissions in the U.S. This paper endeavors to shed light on how a tradable CO_2 permit market might take shape by analyzing plant-level marginal abatement costs. Specifically, the "shadow price" for a ton of CO_2 is identified through a linear programming model, where the shadow price represents the opportunity cost of abatement (in terms of lost revenue) and therefore serves as a proxy for marginal abatement cost.

The remainder of the paper is organized as follows. Section 2 discusses the economic rationale of trading programs and outlines existing allowance trading programs including the Acid Rain Reduction program developed under the 1990 Clean Air Act Amendments, as well as various CO_2 programs in Europe and the United States. Section

2 also reviews approaches for estimating shadow prices. Section 3 presents the model used to identify CO_2 shadow prices in this paper. Section 4 describes the data and procedure used to calculate shadow prices. Section 5 provides the results and interpretation of this model. Finally, Section 6 offers conclusions and suggestions for future research.

Section 2. Prior Research on Allowance Trading Programs and Shadow Prices

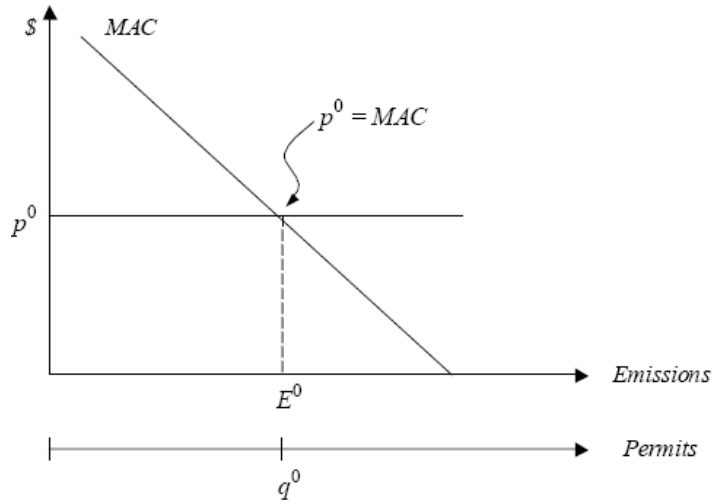
2.1 Utilizing a Property Rights Approach to Curb Externalities: Increasing Economic Efficiency through Permit Trading

Traditionally, government regulation targeting pollution has sought to uniformly control emissions among polluters. This approach, known as "command and control" (CAC), ultimately imposes a "one-size fits all" set of rules on emissions sources, though these rules may take on any number of forms. For instance, a regulation may impose a uniform standard of emissions per kilowatt hour at electric utility plants, or it may require the use of a particular abatement technology such as a scrubber on a smokestack. A major criticism of the CAC approach is that a uniform standard is too rigid and may not represent the least cost abatement strategy for the firm, resulting in a potential efficiency loss given the set of abatement opportunities that could otherwise be pursued. To achieve overall minimum abatement costs, each firm must abate to the point where marginal abatement costs are equalized across firms. As a result, rigid technology standards potentially engender an inefficient abatement scheme by forcing the adoption of a technology with varying levels of implementation costs between firms. Thus, marginal

abatement costs may differ for each firm, meaning that overall costs have not been minimized. This leads to a loss of economic efficiency, as the prescribed quantity of emissions could be reduced at a lower cost through each firm utilizing its own most efficient abatement option.

The concept of permit trading emerged as an alternative to CAC in the early 1970s (Stavins 2003). Under a permit trading scheme, the regulator selects an aggregate emissions target, and a number of permits equal to targeted emissions are distributed to polluting firms covered by the program. These permits may then be traded between firms, as firms with higher marginal abatement costs will find it beneficial to purchase permits from firms with lower marginal abatement costs. Stavins writes that, in theory, if properly designed and implemented, market-based instruments allow any desired level of pollution cleanup to be realized at the lowest overall cost to society, by providing incentives for the greatest reductions in pollution by those firms that can achieve the reductions most cheaply. That is, firms that can reduce pollution cheaply are willing and able to sell excess permits to those firms facing steeper marginal abatement costs. Furthermore, this market flexibility ultimately results in aggregate abatement being achieved at lowest overall cost. That is, the initial reduction of emissions is shifted from all firms—including firms with high abatement costs—to firms with low marginal abatement costs, reducing the overall cost of reducing emissions. Figure 1 below illustrates the relationship between permits and a firm's marginal abatement cost (MAC).

Figure 1. Firm Level Equilibrium of Marginal Abatement Cost and Permits[2]



On the X-axis is the level of emissions for a firm and the number of permits owned by the firm. On the Y-axis is the marginal abatement cost for reducing emissions by one unit at the given level of emissions as well as the market price for permits. In the region to the right of E^0 MAC is less than p^0, the permit market price. As a result, it is cheaper for the firm to reduce emissions rather than purchase a permit for each unit of emissions in excess of E^0. However, in the region to the left of E^0 MAC is greater than p^0. Consequently, it is cheaper for the firm to purchase a permit for each unit of emissions below E^0 rather than reduce emissions further. Thus, the firm will emit E^0 units of emissions, is the point where p^0 equals MAC. Accordingly, the firm will purchase q^0 permits and will always end up emitting at E^0 regardless of the initial permit endowment.

This approach allows each individual firm to pursue its own least-cost strategy for reducing emissions. Note that a CAC approach could match the cost savings of a permit

[2] John Stranlund. Course Lecture Notes. "Natural Resource and Environmental Economics." University of Massachusetts. Spring 2006. Available online at: http://courses.umass.edu/resec262/documents/262Lecture13TransferableDischargePermits.pdf.

market if MAC for all firms could be made equal, but this requires that the standards for each firm be unique to that firm, implying prohibitively high administrative costs. Moreover, a tradable permit program naturally achieves cost-effectiveness since each firm emits at p^0 = MAC. As a result, each firm is operating with the same MAC. In addition, a permit trading scheme remains cost-effective over time as conditions within the industry change, the number of permits is reduced, inflation changes money value, and technological innovations reduce abatement costs. Because firms will always emit where p^0 = MAC, a cost-effective result is always achieved. For this reason, a permit trading program may be preferable to an emissions tax in that the permit trading program naturally adapts to changing conditions while an emissions tax would have to be continually adjusted by policymakers. Indeed, Weitzman (1974) notes that under uncertainty the distinction between a quantity-based approach (permit market) and a price-based approach (tax) is irrelevant in "an infinitely flexible control environment where the planners can continually adjust instruments to reflect current understanding of a fluid situation and producers instantaneously respond…" In such a case he writes that the determination of the approach should be left up to other factors. To be sure, these other factors would likely include the administrative and compliance costs of continually adjusting the price of carbon to meet a quantity target, which, given the Kyoto model, is a likely scenario even if the eventual U.S. target is not as significant as it would be under the Kyoto Protocol. Thus, a permit market regulated by a naturally adjusting price appears superior to a CO_2 tax.

Because the U.S. electric utility industry is responsible for 39 percent of national anthropogenic CO_2 emission, a CO_2 permit trading scheme offers a cost-effective

approach to reduce a lion's share of domestic CO_2 anthropogenic emissions. A number of studies have examined the success of the SO_2 trading scheme set up under the 1990 Clean Air Act Amendments. This paper extends much of this analysis to CO_2, seeking to calculate a shadow price proxy for CO_2 abatement costs at the plant level. The shadow price then enables a picture to develop of how different types of utilities would behave in a CO_2 permit market, total costs associated with reducing aggregate emissions to given levels, and an analysis of whether a role exists for alternative fuels to play in reaching an abatement target.

2.1 Acid Rain Program as a Model for CO_2 Trading

The success of the Acid Rain Program under the 1990 Clean Air Act Amendments has led to global interest in tradable emissions permits to curb greenhouse gases. Kruger (2005) notes that private companies have begun setting voluntary CO_2 emissions targets, some of which are designed to influence a national program. Nine Mid-Atlantic and New England states have also developed a regional allowance trading program, hoping to influence the design of a national trading program. In addition, the European Union (EU) has implemented the largest greenhouse gas allowance trading program to date. Kruger adds that as the "first mover," the EU program could have enormous influence on any international or domestic program.

The extensive literature examining the U.S. SO_2 program has important implications for the design of a CO_2 trading program. Ellerman et al. (2000) report on the history of trading programs, specifically the SO_2 Acid Rain Program. While their analysis focuses on the SO_2 trading program they mention that emissions trading

programs may work well for other types of emissions such as CO_2. Carlson et al. (2000) compare the SO_2 trading program to a uniform emission rate standard among electricity generating units. Their estimates suggest that, with the trading program, the electric utility industry may ultimately save $700-$800 million (1995 dollars) per year in abatement costs. However, retrospective analysis suggests that the gains from trade in the first two years of the program were largely unrealized. They postulate that realized gains from trade were lower than predicted for two main reasons. First, the price of low-sulfur coal was lower during the first years of the market than anticipated. This may be because energy prices were also lower, reducing the cost of transporting coal and effectively making it cheaper. Second, improvements in technology lowered the cost of fuel switching. As a result, plants were able to rely more significantly on lower sulfur coal than in recent years without any substantial equipment modifications, and other plants willing to invest in new technology were able to more cheaply switch to lower SO_2 emitting fuels such as natural gas. The authors note that fuel switching served as a major abatement strategy for SO_2 and suggest that it may serve to inform any potential CO_2 abatement program.

Stavins (1998) states that the Acid Rain Program was so successful in reducing emissions that after the first two years of implementation participating utilities had "banked" more than six million tons. That is, emission levels fell well below set targets, and these allowances could be saved for later use. Because the program allows for banking, however, many of these permits may be utilized at some point in the future, which will effectively reduce the long-term benefits that appear to have been realized in the early years of the program. Additionally, a large number of permit purchasers could

turn out to be speculators buying permits at low prices to sell once regulators tighten emission targets. Stavins arrives at a somewhat different conclusion than Carlson et al. (2000), writing, "Prospective analysis in 1990 suggested that the program's benefits would approximately equal its costs (Portney, 1990), but recent analysis indicates that benefits will exceed costs by a very significant margin (Burtraw, Krupnick, Mansur, Austin and Farell, 1997)." Stavins also considers the political economy of the SO_2 trading program, noting that it is the first break from the traditional command-and-control strategies of previous environmental regulatory regimes. Stavins outlines a general paradigm shift in the late 1980s of the political center, which now had a more favorable view of market solutions to social problems. With the option of an emissions tax or a tradable permit approach, environmental economists preferred the latter, as a tax makes the costs of environmental compliance more visible to consumers, legislators, and firms. Particularly if permits are given away for free, firms are better off with a permit system than an emissions tax.

While the U.S. experience with SO_2 trading yields relevant insights for the design of a CO_2 trading market, there are important differences between a market for SO_2 emissions and CO_2 emissions. Kruger (2005) summarizes the main findings of the current literature comparing the two markets. Kruger recommends that many features of the Acid Rain Program, such as banking of excess emissions reductions over time and strong monitoring and enforcement provisions, should be included in any CO_2 trading program. However, Kruger also suggests some key modifications for a CO_2 trading program. For instance, SO_2 is emitted primarily by coal-fired power plants. Sources of CO_2 emissions are diverse, consisting of anything that burns a fossil fuel. Kruger argues

that instead of trying to regulate each smokestack, an ideal program would cover the entire economy, possibly even regulating producers and refiners of fuels. Including emissions from the transportation sector (affecting mobile sources) would also be preferable and could be made possible by including refineries in the trading program through the quality of fuel they produce.

Kruger continues, stating that most permits in the SO_2 program are allocated free of charge to utility plants. Under a CO_2 program, he suggests that permits might be auctioned to the highest bidder. Because the total value of the permits would be higher in a CO_2 program, this would make it possible to redistribute revenues from the auction or allocate some allowances to energy consumers. Moreover, Kruger finds that a CO_2 program should consider stabilizing allowance prices. This might entail a price ceiling for permits, where the regulator would issue as many permits as the industry wishes to purchase at a given price. This may be necessary considering many scholars believe that CO_2 prices will be more unpredictable than SO_2 prices, and may be caused by the relatively small number of mitigation options for CO_2 and lack of cost-effective post-combustion controls. As long as the long-term trajectory of CO_2 emissions is negative, Kruger notes that a temporary increase in CO_2 emissions is not of serious concern to most scholars.

2.3 Predicted CO_2 Permit Prices in the U.S. and Other Regions

A handful of studies have estimated CO_2 marginal abatement costs for electric power plants and/or estimated CO_2 permit prices under a global or regional market. The EIA International Energy Outlook 2005 estimates marginal abatement costs per metric

ton for Canada, Japan, and Western Europe for varying levels of national reduction in 2010 and 2025. The results of this study are listed in Table 1. Several other studies have estimated CO_2 permit prices for the U.S. The main findings of these studies are included in Table 2. Moreover, observed prices in the European Climate Exchange, the first mandatory and geographically significant CO_2 trading market have risen to about $30 currently from about $9 upon the opening of the market in January 2005. Sixty-five corporate entities are participants in the market, with many able to sell permits to third parties.

Table 1. Projected Carbon Emissions Marginal Abatement Costs for Selected Countries and Regions that have Ratified the Kyoto Protocol[3]

Country/Region	Emissions Reduction from 1990 Level	Projected Marginal Abatement cost per metric ton (2000 $)		Reduction from Domestic Efforts[4]	Reduction from Permit Trading[5]
		2010	2025		
Canada	6%	$26	$36	53.3 (25%)	177.8 (75%)
Japan	6%	$49	$43	70.1 (25%)	210.4 (75%)
Western Europe	8%	$48	$64	273 (50%)	273 (50%)

[3] Energy Information Agency. *International Energy Outlook 2005*. "Energy-Related Carbon Dioxide Emissions." July 2005. Available online at: http://www.eia.doe.gov/oiaf/ieo/.
[4] In percent and million metric tons.
[5] In percent and million metric tons.

Table 2. Estimates of U.S. CO_2 Permit Prices (2000 $)

Organization	Emissions Target	Estimate of Permit Price (Year)	Estimate of Permit Price (Year)
Congressional Budget Office	1990 Emissions Levels	$23 (2008)	$32 (2012)
Energy Information Agency	57 and 224 million metric tons by 2020	$50 (low estimate)	$68 (high estimate)
World Resources Institute	7 percent below 1990 Emissions Levels	$30 (2010)	$40 (2010)

2.4 Calculating Shadow Prices

Several scholars have developed techniques, generally premised on linear programming or Data Envelopment Analysis (DEA) frameworks, to facilitate the calculation of shadow prices for effluents. Färe et al. (1993) build a framework for deriving shadow prices for undesirable outputs in the pulp and paper industry. The authors employ duality theory to determine producer-specific shadow prices, using a Shepard (1970) output distance function to define shadow prices for both good and bad outputs. Their analysis demonstrates that shadow prices can effectively be calculated for non-marketable outputs and note that determining the shadow prices of undesirable outputs will verify whether or not emissions trading would be worthwhile. Specifically, Färe et al. utilize a parametric linear programming approach to model the output distance function. Comparing the output distance function with the revenue function yields the shadow price for each plant. This shadow price represents the opportunity cost in lost electricity generation of reducing emissions by one ton. As a result, lost income from

reduced electricity generation serves as a proxy for marginal abatement cost. Ultimately, the authors suggest that if shadow prices equal marginal benefit to society of emission abatement, then regulations are leading to an efficient allocation of resources. Moreover, "if the marginal benefit of emission control is equal for all firms, then efficient regulation would lead to equal shadow prices across firms." Hetemaki (1995) uses a parametric distance function to econometrically derive shadow prices. Hailu and Veeman (2000) use a parametric distance function to generate efficiency measures and pollution abatement costs. Following the framework laid out by Färe et al. (1993), they use this model to calculate shadow prices for the Canadian pulp and paper industry.

Other papers have used similar frameworks to characterize SO_2 abatement costs for the electric utility industry. Coggins and Swinton (1996) utilize the Färe et al. (1993) approach to calculate plant-specific SO_2 shadow prices for a panel of Wisconsin coal-burning power plants from 1990-1993. The authors find an average shadow price of $292.70 per ton of SO_2 for the panel, a price comparable to other shadow prices calculated for the Midwest, but still higher than allowances traded in the early years of the Acid Rain Program. Swinton (1998) expands upon this analysis by including coal-burning plants in Wisconsin, Minnesota, and Illinois, and by including abatement technology as an input. He finds that before SO_2 trading began marginal abatement costs varied widely across plants. Moreover, he also finds that plants with the highest emissions rates also tend to have the lowest marginal abatement costs, perhaps explaining the lower-than-anticipated prices for emissions allowances. Both of these studies utilize a parametric linear programming approach to model the output distance function described above.

In a more recent analysis, Swinton (2002) calculated shadow prices for a panel of Florida plants from 1990-1998. Again, the output distance function approach is used. Observed transaction decisions are used to calculate plant-specific cost savings of SO_2 trading. In some cases, cost savings appear to be negative. Yet Swinton finds that enough heterogeneity exists in the industry for allowance trading to yield costs savings for most plants, although he concludes that significant gains from trade have not materialized. Färe et al. (2005) employ a quadratic directional output distance function to test the efficiency of electric utilities and to calculate shadow prices before and after Phase I of the Acid Rain Program. This approach is used with the understanding that it has not been widely employed in other studies. The authors find that reducing inefficiency within individual plants could reduce annual SO_2 emissions by 4000-6000 tons. In addition, using the stochastic frontier method shadow SO_2 prices are calculated at $76/ton in 1993 and $142/ton in 1997, values consistent with actual market prices. However, deterministic estimates of shadow prices are much higher, around $1100 in 1993 and $1973 in 1997. Thus, large gains in economic efficiency are possible through allowance trading, though these gains will diminish over time and become increasingly expensive as the output elasticity of substitution indicates that already efficient plants have fewer substitution options. However, these results may be misleading since the authors do not estimate separate models based on abatement capital.

Rezek and Blair (2005) utilize the Färe et al. (1993) output distance function framework to calculate SO_2 shadow prices for electric utility plants after Phase I of the Acid Rain Program. Shadow prices are demonstrated to follow market outcomes, and the variance of abatement costs decreased over time, suggesting a substantial decrease in

abatement cost heterogeneity. This finding is consistent with the efficient market hypothesis, where marginal abatement costs are equal if the market is working efficiently. In this study, the marginal abatement costs are not equal, but the decreasing variance over time suggests that they at least seem to be converging.

Data Envelopment Analysis (DEA) represents another approach to estimating efficiency. DEA typically measures global efficiencies of production systems as revealed through cross-sectional data. One advantage of DEA is that it is nonparametric, whereas other approaches impose a possibly restrictive functional form. Moreover, DEA may easily measure multi-output production systems, though Park and Lesourd (2000) reveal that this is not a significant advantage over the duality approach followed in this paper. DEA is a common method for estimating plant efficiency in the electric utility industry. For instance, Pollitt (1996) examines an international sample of 78 nuclear power plants both publicly and privately owned. Following the calculation of efficiency scores for each plant using DEA, Tobit/OLS analysis is used to test the null hypothesis that ownership has no effect on efficiency. The results suggest that the 13 UK plants in the sample could stand to benefit at least marginally from lowered staffing levels.

Yaisawarng and Klein (1994) use DEA to develop a cumulative Malmquist input-based productivity index for 61 coal-burning plants in the U.S. electric utility industry from 1985-5989. They measure the efficiency of plants that must meet strict emissions standards while also satisfying electricity demand. The Malmauist productivity change index is then broken down into changes in plant efficiency, changes in scale efficiency, and changes in technology. The analysis accounts for the inclusion of undesirable inputs (sulfur) and undesirable outputs (SO_2) in the process of producing a desirable output (net

generation) using conventional inputs (labor, capital, fuel). Including desirable and undesirable inputs in the analysis credits each plant's ability to choose the best means of meeting environmental control criteria. This allows for an unbiased measure of productivity in an industry under environmental regulations. Aiken and Pasurka (2003) use an output-based translog distance function to estimate shadow prices for PM-10 and SO_2 emissions for 19 industries in the U.S. manufacturing sector from 1970-1996. Similar to Yaisawarng and Klein (1994), these shadow prices may be used to adjust traditional total factor productivity growth indexes to account for the reallocation of inputs from the production of desirable outputs to pollution abatement activities. This adjusted measure of total factor production reveals that adjusted productivity for several industries is actually much higher than the traditional measure of productivity.

Despite significant study of SO_2 shadow prices, few scholars have ventured to estimate CO_2 shadow prices. Maradan and Vassiliev (2005) study how abatement costs vary through different stages of a country's economic development. CO_2 shadow prices are calculated for 76 developing and developed countries, and abatement costs are deemed significantly higher for developing countries. Given growing interest in a national CO_2 trading market, the calculation of CO_2 shadow prices in U.S. electric utilities will provide insight into the likely price range of CO_2 allowances, as well as help identify what types of plants are more likely to buy or sell allowances in such a market. It is important to note that the U.S. electric utility industry is only a large subset of CO_2 emitters. However, given the administrative difficulties associated with a comprehensive national carbon abatement strategy covering all sources as suggested by Kruger (2005), a CO_2 trading market for electric utilities may offer a relatively easier mechanism for

quickly and substantially reducing domestic CO_2 emissions. That is, an allowance trading market might help pick the low-hanging fruit, buying more time to develop and implement more complicated domestic and international CO_2 abatement strategies.

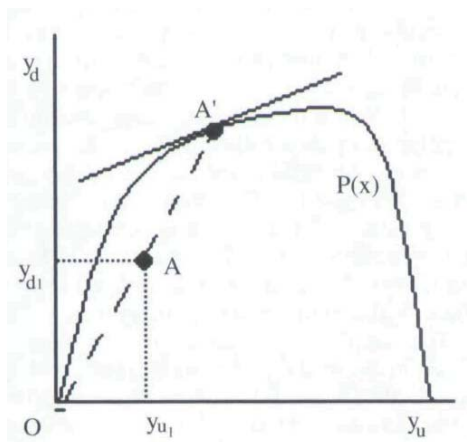
In this study, I follow the techniques employed by several previous studies, including Rezek and Blair (2005) and Färe et al. (1993), to calculate shadow prices for electric utility plants. However, unlike these studies, this paper focuses on shadow prices for CO_2. The Färe et al. (1993) approach is chosen specifically for two several reasons. First, it has been used extensively and is commonly accepted and, second, logical constraints may be imposed upon shadow prices to more accurately reflect operating conditions within the electric utility industry.

Section 3. Model for Calculating Shadow Prices

Following the model described by Rezek and Blair (2005) and Färe et al. (1993), assume a given technology uses a set of $x \in R_+^N$ inputs to produce a set of $y \in R_+^M$ outputs. Let the output set, P(x), be a closed, bounded, and convex set describing all technically feasible output vectors. A subset of these outputs, $y_d \in R_+^D$, will be defined as "goods," while the remaining outputs, $y_u \in R_+^U$, will be defined as "bads." As Färe et al. (1993) suggest, a fundamental asymmetry exists between the good and bad outputs. That is, goods may be rid of without cost, while bads may only be reduced by foregoing some beneficial output or increasing abatement inputs. As an example, output set P(x), illustrated in Figure 2, contains one good output and one bad output. Point A falls within

the feasible set. The point on the horizontal axis directly below point A remains in the feasible set, so the good is freely disposable, yet the point on the vertical axis to the left of A is not included in the feasible output set, and so the bad is not freely disposable.

Figure 2. Output Distance Function[6]



Shepard (1970) describes the technical relationship between inputs and outputs as a mapping of a multiple-output, multiple-input production process onto a real line. The resulting line is the output distance function, D_o (x, y), which measures the minimum scalar, θ, such that y/θ is within the feasible set:

(1) $$D_o(x, y) = \min\{\theta : y/\theta \in P(x)\}$$

The output distance function measures the maximum potential radial output expansion given observed inputs, shown as (OA/OA') in Figure 2. The distance function is equal to one if and only if the observation is on the frontier of the output set P(x), while values less than one indicate the presence of inefficiency or production on the interior of P(x).

[6] Rezek and Blair (2005), p. 329

This paper bases the yardstick of efficiency on observed data and therefore ignores systematic inefficiency present in the electric utility industry. The output distance function is a continuous function of *x* and *y*, is quasi-concave and nonincreasing in *x*, and exhibits homogeneity of degree 1 in *y*. As in Rezek and Blair (2005), it is assumed to be nondecreasing in y_d and nonincreasing in y_u. This implies that increased production of goods increases efficiency but increased production of bads reduces efficiency. The output distance function is also compatible with weak output disposability, implying that a radial contraction of outputs is feasible with a given set of inputs, or if $y \in P(x)$ and $\theta \in [0,1]$, then y$\theta \in P(x)$. Because effluents may not be eliminated without reducing some desirable output or increasing abatement inputs, weak output disposability is a reasonable assumption in this context, making the output distance function intuitively appealing.

Shephard (1970) shows that the output distance function is dual to the revenue function under straightforward regularity conditions, implying

(2) $$R(x, p) = \sup_{y}\{py : D_o(x, y) \leq 1\}$$

(3) $$D(x, p) = \sup_{p}\{py : R(x, y) \leq 1\},$$

where *p* is the vector of output prices. Färe et al. (1993) solves the LaGrangian implied by Equation (2), yielding first-order conditions as given by

(4) $$p = R(x, p) * \nabla D(x, y),$$

where ∇ is the gradient operator. By applying the envelope theorem to the dual relationship given in Equation (3) and substituting the result into Equation (4), Färe et al. (1993) show that

$$(5) \qquad \nabla D(x, y) = p^*(x, y),$$

where p^* is defined as the revenue maximizing output price vector or the revenue-deflated output shadow price. Therefore, the ratio of the derivatives of the distance function with respect to the outputs yields the relative shadow prices. In the two-output case:

$$(6) \qquad \frac{\partial D_0(\cdot)}{\partial y_u} \Big/ \frac{\partial D_0(\cdot)}{\partial y_d} = \frac{p_u^*}{p_d^*}.$$

Following Aigner and Chu's (1968) estimation procedure, restrictions can be placed on the signs of these derivatives to allow asymmetric treatment of desirable and undesirable outputs. Shadow prices of goods and bads are restricted to be nonnegative and nonpositive, respectively, reflecting the assumptions that $D_o(x, y)$ is nondecreasing in y_d, and nonincreasing in y_u. In the one-good, one-bad case, these restrictions act to impose a positive slope on the hyperplane tangent to the output set P(x) in the region under consideration. The slope of the hyperplane tangent to point A' in Figure 2 illustrates the left-hand side of Equation (6).

Solving Equation (6) for the shadow price of the undesirable output yields

$$(7) \qquad p_u^* = p_d^* \left[\frac{\partial D_0(\cdot)}{\partial y_u} \Big/ \frac{\partial D_0(\cdot)}{\partial y_d} \right].$$

To compute the implicit price of the bad, I follow Färe et al. (1993) and Rezek and Blair (2005) in assuming that the shadow price of the desirable output equals its observed price. As Rezek and Blair (p. 330) go on to state,

> "In the context of the output distance function, with its dual relationship to the revenue function, these shadow prices represent the marginal revenue associated with an additional unit of abatement. The shadow prices of bads are reflective of the marginal rate of transformation between the desirable and undesirable outputs and, as such, represent the value of the electricity that is foregone when emissions are reduced."

As noted above, several previous studies employ this method to restrict effluent shadow prices in the context of electricity production (Coggins and Swinton, 1996; Swinton, 1998, 2002) and pulp and paper production (Färe et al., 1993; Hailu and Veeman, 2000).

In this paper the output distance function is calculated by the translog specification employed by Färe et al. (1993) and Rezek and Blair (2005):

$$
\begin{aligned}
(8) \qquad \ln D(x,y) = \alpha_0 &+ \sum_{i=1}^{M} \alpha_i (\ln y_i) \\
&+ \sum_{j=1}^{N} \beta_j (\ln x) \\
&= (0.5) \sum_{i=1}^{M} \sum_{i'=1}^{M} \alpha_{ii'} \\
&\times (\ln y_i)(\ln y_{i'}) \\
&+ (0.5) \sum_{j=1}^{N} \sum_{j'=1}^{N} \beta_{jj'} \\
&\times (\ln x_j)(\ln x_{j'}) \\
&+ \sum_{i=1}^{M} \sum_{j=1}^{N} \gamma_{ij} (\ln y_i)(\ln x_j)
\end{aligned}
$$

where the α_{ii}, β_j, and γ_{ij} are unknown parameters to be estimated. The Färe et al. (1993) framework uses linear programming to solve for the combination of parameters that yields the best-fit distance function given the observed input and output data. The theoretical properties of the output distance function and the assumptions of the model are incorporated into the linear program as constraints. As Färe et al. (1993) explain, this functional form is flexible and does not impose strong disposability on outputs, making this form particularly useful when calculating a shadow price. Thus, the following linear program can be solved to determine observation-specific shadow prices:

$$
(9) \qquad \max_{\alpha,\beta,y} \sum_{k=1}^{K} \ln D(x^k, y^k)
$$

subject to

$$
(10) \qquad \ln D(x^k, y^k) \le 0 \qquad k = 1, \ldots, K
$$

$$
(11) \qquad \partial \ln D(x^k, y^k) / \partial \ln y_d^k \ge 0 \qquad k = 1, \ldots, K
$$

(12) $\partial \ln D(x^k, y^k) / \partial \ln y_u^k \leq 0 \qquad k = 1, \ldots, K$

(13) $\partial \ln D(x^k, y^k) / \partial \ln x^k \leq 0 \qquad k = 1, \ldots, K$

(14a) $\sum_i \alpha_i = 1$

(14b) $\sum_i \alpha_{ii'} = 0 \qquad i' = 1, \ldots, M$

(14c) $\sum_i \gamma_{ij} = 0 \qquad j = 1, \ldots, N$

(15a) $\alpha_{ii'} = \alpha_{i'i} \qquad i = 1, \ldots, M,\ i' = 1, \ldots M$

(15b) $\beta_{ii'} = \beta_{i'i} \qquad i = 1, \ldots, M,\ i' = 1, \ldots M$

where the sample consists of K observations. As prescribed by Rezek and Blair (2005), Equation (10) requires that each observation remain in the feasible set. Equations (11) and (12) correspond to the assumptions of nonnegative and nonpositive shadow prices for the desirable and undesirable outputs, respectively. Equation (13) requires that the output distance function be nonincreasing in inputs. Equations (14a)-(14c) require the distance function to be homogeneous of degree one in outputs. Finally, Equations (15a) and (15b) impose symmetry on the interaction parameters of the translog functional form. These restrictions reflect the assumptions made previously regarding the properties of the output distance function and allow for the calculation of efficiency measures and the computation of the accompanying shadow prices.

In order to calculate shadow prices for each observation, this paper expounds upon Rezek and Blair's Equation (7) such that derivatives from the log distance function

can be used to calculate shadow prices. Beginning with Equation (7), the end result was achieved as follows:

$$(7) \qquad p_u^* = p_d^* \left[\frac{\partial D_0(\cdot)}{\partial y_u} \Big/ \frac{\partial D_0(\cdot)}{\partial y_d} \right]$$

$$(15) \quad (a) \qquad \frac{\partial D(\cdot)}{\partial y_u} = \frac{\partial D(\cdot)}{\partial \ln D_0(\cdot)} \cdot \frac{\partial \ln D_0(\cdot)}{\partial \ln y_u} \cdot \frac{\partial \ln y_u}{\partial y_u}$$

$$(16) \quad (b) \qquad \frac{\partial D(\cdot)}{\partial y_d} = \frac{\partial D(\cdot)}{\partial \ln D_0(\cdot)} \cdot \frac{\partial \ln D_0(\cdot)}{\partial \ln y_d} \cdot \frac{\partial \ln y_d}{\partial y_d}$$

Thus, substitution implies

$$(17) \qquad p_u = p_d \left[\left(\frac{\partial \ln D_0(\cdot)}{\partial \ln y_u} \cdot \frac{\partial \ln y_u}{\partial y_u} \right) \Big/ \left(\frac{\partial \ln D_0(\cdot)}{\partial \ln y_d} \cdot \frac{\partial \ln y_d}{\partial y_d} \right) \right]$$

Since $\frac{\partial \ln y_u}{\partial y_u} = \frac{1}{y_u}$ and $\frac{\partial \ln y_d}{\partial y_d} = \frac{1}{y_d}$, then

$$(18) \qquad p_u = p_d \left[\frac{\partial \ln D(\cdot)/\partial \ln y_u}{\partial \ln D(\cdot)/\partial \ln y_d} \right] \cdot \frac{y_d}{y_u}$$

Section 4. Data

The computation of CO_2 shadow prices is based on a sample of 518 electric power plants (note: the sample includes both utilities and non-utilities) that emit CO_2 in the year 2000. Plants producing solely from nuclear, wind, hydro, etc., or a combination of the above were thus excluded from the analysis. Data were obtained from a number of sources containing both plant level (EPA eGrid 2000, EIA 2000 Form 423, and FERC

Form 1) and utility level (EIA 2000 Form 861) data. Altogether, the plants included in this study accounted for 1,953 millions tons or approximately 83% of total CO2 emissions from the electric utility industry in 2000 (EIA 2000).[7]

Data on net electricity generation from fossil fuel sources only, total annual CO_2 emissions, and nameplate capacity, or the maximum available generation capability, were obtained from the EPA eGrid 2000 Database. In this study, nameplate capacity is used as a proxy for capital (see Nemoto and Goto, 2003; Pollitt, 1996; Färe et al., 2005; Rezek and Blair, 2005; etc.). Data on average heat content of fuels purchased were gathered from EIA Form 423, and data on fuel consumption were taken from EIA Form 759. The average number of employees, the measure of labor input, were obtained from FERC Form 1 2000 and 2001 data along with EIA Form 412 2001 data. Data from a consistent year, particularly 2000, would have been preferred but proved difficult to obtain. Nevertheless, the average number of employees is assumed to remain fairly consistent between years, and so the inclusion of 2001 data for some plants is not expected to significantly alter the results. In addition, utilities reporting no employee number for any plant in FERC Form 1 were excluded form the analysis under the assumption that the "zeros" listed were not actual employee numbers. Likewise, cases where all plants for a given utility have zero employees listed in EIA Form 412 were also excluded. It is assumed that these reports are not accurate.

Rezek and Blair (2005) calculate a proxy for electricity price using revenue earned by the utility from the sale of electricity divided by net electricity generated. This calculation, however, does not account for instances where a plant purchases electricity from another plant to sell to its own customers. To compensate for this, in this study the

[7] http://www.eia.doe.gov/oiaf/1605/gg01rpt/carbon.html

price of electricity generated at each plant, based on EIA Form 861, was assumed to be equal to average revenue from all electricity sales divided by total electricity dispatched. Specifically, a per unit "price" of electricity was calculated as resale and retail revenue divided by total electricity dispatched, where resale revenue is defined as revenue received for the sale of wholesale power to other electric utilities, for resale to others, either electric utilities or retail consumers; and retail revenue is defined as revenue received for the direct sale of energy to retail customers (this entry does not include revenue for retail delivery services provided to customers who selected other energy suppliers, as in "retail wheeling" programs in deregulated markets). Because revenue data is only available at the utility level, it is assumed that each plant owned by a given utility has the same price. The weighted average price of electricity in this study is 5.28 cents per kilowatt hour, a figure slightly lower than the average revenue per kilowatt hour for all fuel types observed in 2000 of 6.68 cents per kilowatt hour. Given that this paper only includes facilities burning fossil fuels, which generally offer lower production costs, this proxy appears reliable.

Plants are grouped according to fuel usage: coal and gas; coal and oil, no gas; and gas, no coal. Because of the use of different technologies between these groups, the distance function may not yield accurate estimates when based on an estimated model using the entire sample. Thus, the distance function is calculated separately for each group to measure efficiency only between plants using similar fuel technology. The descriptive statistics for inputs, outputs, and electricity price are listed in Table 3.

Table 3. Descriptive Statistics

	All Groups	**Group 1** Coal and Gas	**Group 2** Coal and Oil, no Gas	**Group 3** Gas, no Coal
Net Generation (MWh)	3,670,928.90 (4,308,648.40)	3,793,318.30 (3,697,727.59)	5,772,975.06 (5,232,201.88)	1,507,278.05 (2,060,349.52)
CO_2 Emissions (tons)	3,770,787.88 (4602681.05)	4,228,825.82 (4,063,388.40)	6,248,989.11 (5,513,794.60)	1,006,480.44 (1,233,095.18)
Nameplate Capacity (MW)	788.80 (716.98)	798.55 (686.40)	1,011.06 (831.11)	562.21 (522.34)
Average Heat Input (billion BTUs)	36,809.35 (42,664.54)	38,599.14 (38,084.7)	57,568.6 (51,823.98)	15,046.32 (18,073.78)
Electricity Price (US$/MWh)	55.82 (15.19)	52.96 (11.73)	51.58 (12.29)	61.96 (17.72)
Employees	104.03 (97.94)	121.86 (77.01)	155.81 (118.63)	40.64 (28.63)

Mean values.
Standard Deviation in parentheses.

Section 5. Results

Using the framework described in Section 3, the unknown parameters for the output distance function given in Equation (8) are estimated and integrated with the input and output data to yield plant-specific distance function values and shadow prices. Premium Solver Platform 7 for Excel by Frontline System, Inc. is used to solve the linear program. The average output distance function value for each group is listed in Table 4. Overall, technical efficiency ranges from 0.03 to 1, indicating wide variation in

efficiency. The mean indicates that, on average, plants are about 64 percent efficient. Studies of U.S. plants with regard to SO_2 emissions find relatively higher levels of efficiency. Rezek and Blair (2005) report 83.5 percent efficiency, Coggins and Swinton (1996) report 94.6 percent efficiency, and Färe et al. (2005) report 80.4 percent efficiency. Note that these estimations are for U.S. electric power plants under the mandatory Acid Rain Program. Because U.S. electric power plants may not necessarily be trying to be efficient with regard to CO_2 emissions, this could explain why estimated efficiencies from this model are relatively low. The efficiency results suggest that plants could enjoy significant cost savings, in lieu of a CO_2 market, by altering its operations.

Table 4. Efficiency (D_0)

	Total	**Group 1** Coal and Gas	**Group 2** Coal and Oil, no Gas	**Group 3** Gas, no Coal
Mean	0.64	0.64	0.75	0.54
Minimum	0.03	0.18	0.10	0.03
Maximum	1	1	1	1
Std. Deviation	0.22	0.22	0.19	0.21

Using Equation (18) shadow prices are computed for each plant. The average shadow prices for each group are reported in Table 5. Including plants from all groups, the average shadow price is $39.97/ton.

Table 5. CO_2 Shadow Price Calculations ($/ton)

	All Groups	**Group 1** Coal and Gas	**Group 2** Coal and Oil, no Gas	**Group 3** Gas, no Coal
Mean	39.97	53.95	50.67	20.09
Minimum	0	0	0	0
Maximum	467.97	388.42	467.97	343.05
Std. Deviation	55.58	48.85	66.84	39.87

For some plants the estimated shadow price was infinite. This was the case with one plant in Group 1, one plant in Group 2, and one plant in Group 3. In these cases the constraint that the derivative of the translog distance function with respect to the log of net generation was zero or near zero. To compute estimated averages that are a better representation of the true average, the shadow prices for these plants were assumed to be equal to the highest finite price in the group. Keeping the infinite prices in the model would distort the reported mean and decrease the usefulness of this model, and removing them was deemed inappropriate. Thus, by keeping these values relatively high, they still are significant within the model but do not distort it beyond usability. Ultimately, estimates of CO_2 market prices are not affected by this assumption, as the infinite costs would only come into play under an implausible scenario whereby industry emissions are driven to zero.

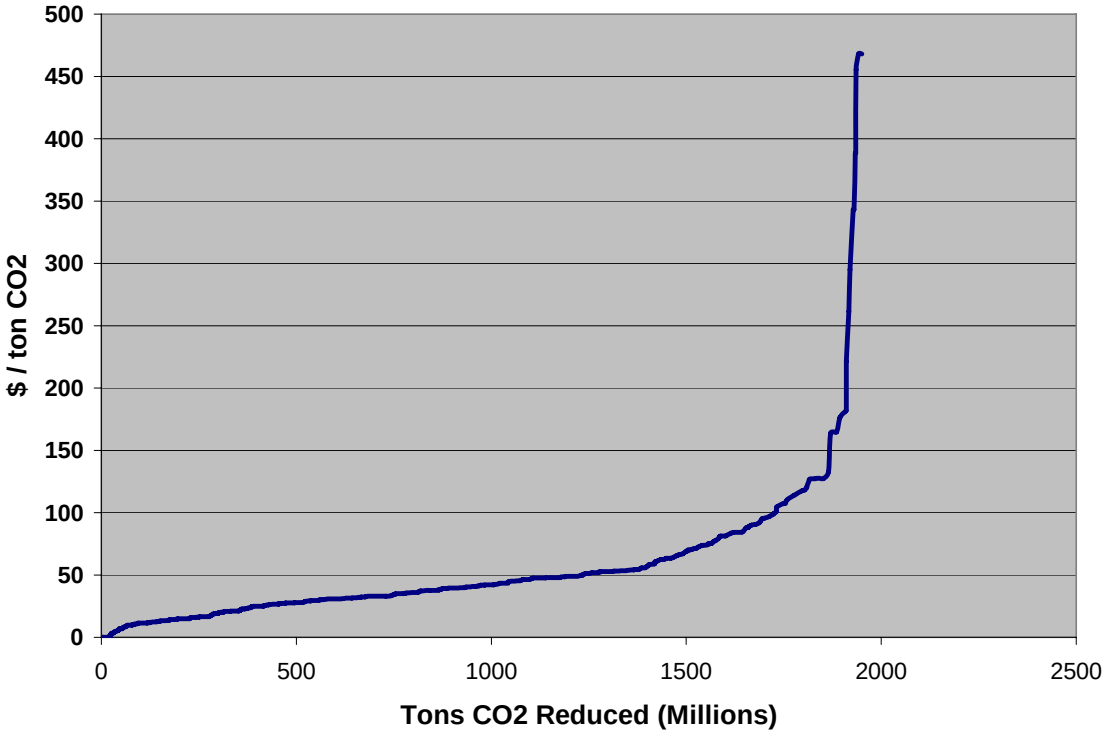
Based on these results, this paper discusses several implications for a CO_2 trading permit program in the U.S. electric utility industry. First, these shadow prices may be used to construct an industry marginal abatement cost curve. Calculating the relevant

area under the curve suggests how much given levels of CO_2 abatement will cost. Second, the variation in shadow prices between groups provides insight into what types of plants would seek to purchase or sell permits; that is, how different types of plants would be affected by a permit trading program. In addition, marginal abatement cost curves can be constructed for each group. Finally, given targeted CO_2 emissions reductions levels, the increased cost of electricity production from fossil fuels due to marginal abatement costs allows for comparison with different types of non-CO_2 emitting fuels (i.e. nuclear and hydroelectric) to determine if they are a cost-effective alternative given the higher costs stemming from a CO_2 permit market to reduce CO_2 emissions.

5.1 CO_2 Marginal Abatement Costs in the U.S. Electric Utility Industry

The calculation of shadow prices allows for the estimation of a lower-bound industry marginal control cost curve. Under the assumption that plant-specific marginal costs are equal to the shadow price across all levels of abatement, the costs of reducing given levels of CO_2 may be obtained. To illustrate this concept, assume the lowest shadow price was $0.50 and this plant generates 1,000 tons. The cost for controlling each ton up to 1000 would be $0.50 per ton. If the next lowest shadow price was $1 and this plant generates 500 tons, the industry marginal cost for each of the next 500 tons would be $1, and so on. Because plant marginal abatement costs are assumed to be constant, the curve represents a lower bound industry MAC curve. It is likely that plant marginal abatement costs are increasing, particularly for high levels of abatement. The lower-bound industry abatement cost curve is presented as Figure 3.

Figure 3. Industry Marginal Abatement Cost



In order to comply with the Kyoto Protocol, the U.S. would be expected to reduce CO_2 emissions to 7 percent below 1990 levels. Table 6 lists the levels of CO_2 emissions for 1990 and 2000 for the U.S. and Table 7 lists the levels of CO_2 emissions specific to the U.S. electric utility industry.

Table 6. U.S. Anthropogenic Carbon Dioxide Emissions[8]

Total National CO_2 Emissions	(Million Metric Tons)
Estimated 2000 Emissions	5,806.1
Change Compared to 1999	174.8
Change from 1999 (percent)	3.1%
Estimated 1990 Emissions	4969.9
Change Compared to 1990	836.2
Change from 1990 (percent)	16.8%
Average Annual Increase, 1990-2000 (percent)	1.6%
7 Percent Below 1990 Emissions	4622.01
Required Reduction from 2000 National Emissions to Meet Kyoto National Target	1184.09
Required Percent Reduction from 2000 National Emissions to Meet National Kyoto Target	20.4%

[8] Adapted from *Emissions of Greenhouse Gases in the United States 2000: Carbon Dioxide*. EIA. 2002. Available online at: http://www.eia.doe.gov/oiaf/1605/gg01rpt/carbon.html.

Table 7. Electric Utility Industry Carbon Dioxide Emissions[9]

Total Electric Utility Industry CO_2 Emissions	
Electric Utility Industry 2000 Emissions (million metric tons)	2,252.1
Electric Utility Industry 1990 Emissions (million metric tons)	1,790.3
Industry Change Compared to 1990 (million metric tons)	461.8
Change from 1990 (percent)	25.8%
7 Percent Below 1990 Industry Emissions	1664.98
Required Reduction from 2000 Industry Emissions to Meet Proportional Kyoto Target (million metric tons)	587.12
Required Percent Reduction from 2000 Industry Emissions to Meet Proportional Kyoto Target	26.1%

Because the electric utility industry is responsible for 39 percent of CO_2 emissions in 2000, making it the largest single source of CO_2, it is likely that any reduction program would require the industry to reduce emissions beyond its proportional share of total emissions. That is, given the relatively small number of emissions sources, it would be much easier to regulate the electric utility industry than the transportation sector, the next largest contributor of domestic CO_2 emissions at 33 percent (EIA 2005). Thus, for example, under the rubric of the Kyoto Protocol, the industry would likely be responsible for reducing somewhere between 587.12 million metric tons (7 percent below the industry's 1990 emissions levels) and 1,184.09 million metric tons (7 percent below

[9] Adapted from *EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003, Chapter 3: Energy*. EPA. 2005. Available online at http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR69V4ZT/$File/05energy.pdf.

national 1990 emissions levels). Subsequently, this paper presents two major scenarios of reduction targets to predict industry marginal abatement costs and, hence, the market permit price for one ton of CO_2. The first scenario, labeled the "Kyoto Protocol Scenario" (KPS), entails meeting the Kyoto target of 7 percent below 1990 emissions levels. The second scenario, labeled the "1990 Level Scenario" (1990S), entails reducing 2000 emissions to 1990 levels, a proposal made by several in Washington, DC. Further, the following analysis presents upper bound (UB) and lower bound (LB) CO_2 permit price estimates under the two scenarios. The upper bound estimation assumes that the electric utility industry will be the sole sector responsible for meeting emissions targets under both scenarios. The lower bound estimation assumes that the electric utility industry will only be responsible for reducing its proportional share of national emissions and not compensating for any other sectors to meet the targets of both scenarios. The actual industry target for any CO_2 abatement program would likely fall between these bounds, as the electric utility industry would likely object to bearing the full burden of abatement while the relatively small number of emissions sources reduce the administration and compliance costs of an abatement program. As a result, the upper and lower bounds presented in this analysis are merely suggested reference points given varying potential abatement targets. Tables 8 and 9 present the estimations from these scenarios.

Table 8. Upper and Lower Bound Estimates of a Permit Price under the Kyoto Protocol Scenario (KPS)

	Lower Bound	Upper Bound
Total Reduction (million metric tons)	587.12	1184.09
Estimated Permit Price ($/ton)	30.70	48.48
Total Abatement Cost	$10,930,957,788	$34,275,114,659

Table 9. Upper and Lower Bound Estimates of a Permit Price under the 1990 Level Scenario (1990S)

	Lower Bound	Upper Bound
Total Reduction (million metric tons)	461.8	836.2
Estimated Permit Price ($/ton)	27.00	37.40
Total Abatement Cost	$7,281,583,636	$18,735,865,331

Thus, if a domestic permit program were implemented to comply with the Kyoto target, the likely resulting permit price would lie somewhere between $30.70/ton and $48.48/ton. Table 10 presents estimates of permit price and total average cost for increments between these bounds. These values, including those estimated for the two scenarios, are further analyzed in section 5.3.

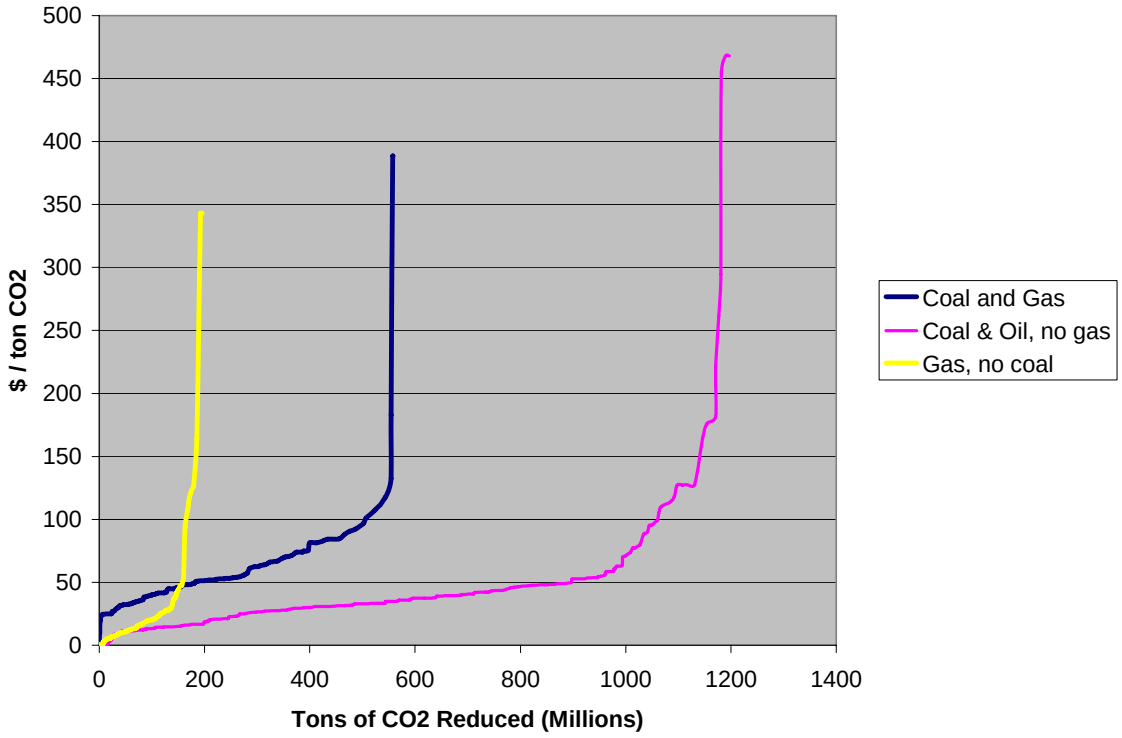
Table 10. Permit Price and Total Average Cost Estimates

Quantity of Reduction (million metric tons)	Percent Reduction from Total Industry Emissions	Permit Price ($/ton)	Total Abatement Cost (TAC)
500	22.2%	27.90	$8,429,311,089
600	26.6%	30.80	$11,077,165,127
700	31.1%	32.90	$14,118,104,555
800	35.5%	35.80	$17,554,110,196
900	40.0%	39.50	$21,979,919,622
1,000	44.4%	42.10	$25,174,073,027
1,100	48.8%	46.60	$30,282,864,559

5.2 Behavioral Response to a CO_2 Permit Trading Program by Group

The average CO_2 shadow price among all plants is $39.97/ton. However, the shadow prices do differ between the three groups. Group 1 (coal and gas) plants have an average shadow price of $53.95/ton, Group 2 (coal and oil, no gas) plants have an average price of $50.67/ton, and Group 3 (gas, no coal) averages $20.09/ton. This suggests that, on average, plants burning natural gas face significantly smaller costs in reducing CO_2 emissions on the margin. If a CO_2 permit trading program were established, Group 3 plants would likely benefit from the sale of permits, as many firms could substantially reduce CO_2 emissions for less than the market price of a permit. However, a comparison of all three groups' marginal abatement cost curves, depicted in Figure 4, reveals an important caveat.

Figure 4. Comparison of Group-Specific Marginal Abatement Cost Curves



As Table 11 illustrates below, Group 3 plants make up only 15.38 percent of net generation and account for only 9.99% of total emissions in the sample. This implies that as the abatement increases, the percent of total production affected by abatement strategies rises disproportionately for Group 3 plants relative to the other groups. Ultimately, as the number of tons to be reduced approaches 200 million, further reduction essentially becomes cost-prohibitive.

Table 11. Percentage of Net Generation in Sample and CO_2 Emissions by Group

Group	Net Generation (MWh)	Percent of Net Generation in Sample	CO_2 Emissions (tons)	Percent of CO_2 Emissions in Sample
Group 1: Coal and Gas	500,718,015	26.33%	558,205,007.5	28.58%
Group 2: Coal and Oil, no Gas	1,108,411,211	58.29%	1,199,805,908	61.43%
Group 3: Gas, no Coal	292,411,942	15.38%	195,257,205.8	9.99%
Total	1,901,541,169	100%	1,953,268,122	100%

The share of total emissions and net generation suggests that the total abatement quantity may influence group behavior under a tradable permit program. Because all three groups would share in the reduction effort, no one group would be in danger of approaching its limit. Thus, Group 3 plants, with a lower average shadow price, are likely to sell permits to Groups 1 and 2, both with significantly higher average shadow prices. Furthermore, the EPA reports that coal contains the highest amount of carbon per unit of energy, while petroleum has about 25 percent less carbon than coal, and natural gas about 45 percent less (EPA 2001). Where possible, some plants might switch from coal or petroleum to burn natural gas. This could dramatically reduce a plant's CO_2 emissions, though the cost would vary depending on new levels of demand for natural gas. Thus, a plant-specific study accounting for each plant's ability to switch fuels and estimate natural gas prices based on market conditions would prove valuable in determining how significant fuel switching can be in CO_2 reductions. Ultimately, though, the results of this paper

indicate that Group 3 plants stand to benefit the most from a tradable permit program while Group 1 and 2 plants may be at a relative disadvantage.

5.3 Influence of Marginal Abatement Costs on Fuel Choice

Given the increased cost in generation from an abatement level, fossil fuel technologies may be compared with non-greenhouse gas emitting technologies to compare for cost-effectiveness in achieving the targeted CO_2 emissions reduction. Specifically, dividing total abatement cost by total net electricity generation yields the cost of abatement in dollar per kilowatt terms. To obtain specific costs for coal and natural gas, this is done using estimates for Group 2 and 3 plants, respectively. These abatement costs can then be added to current levelized costs of fossil fuel electricity generation to estimate new levelized fuel costs under a CO_2 trading program with a targeted level of emissions. A levelized electricity generation cost is estimated as a function of capital cost, fuel cost, operation and maintenance costs, and other costs over the lifetime of a power plant, usually 30 years. Levelized costs by fuel technology were obtained from the *1996 Energy Technology Status Report* published by the California Energy Commission and are reported in Table 12. Note that these figures are adjusted from 1993 constant dollars to 2000 dollars using CPI. Increased cost from given levels of abatement for plants in Groups 2 and 3 are reported in Table 13.

Table 12. Levelized Cost of Electricity Generation Technologies[10]

Fuel Type	Levelized Cost Per Kilowatt Hour (cents/kWh adjusted for 2000 $)
Natural Gas (conventional combined cycle)	4.14-4.62
Coal (pulverized)	4.02-4.62
Nuclear (pressurized water reactor)	6.63-9.23
Geothermal (vapor-dominated resource)	4.26-7.56
Hydroelectric (conventional)	3.24-6.63
Biomass (direct combustion)	6.15-11.72
Municipal Solid Waste (mass burn)	1.76-4.02
Wind (utility scale)	4.02
Solar Thermal (parabolic trough)	7.46-8.76

[10] Adapted from *1996 Energy Technology Status Report*. California Energy Commission. Dec. 1997. Costs are "levelized over a typical lifetime (30 years) beginning in 2000." All costs are for publicly owned utilities and are adjusted from 1993 constant dollars to 2000 dollars using CPI. Report available online at: http://www.energy.ca.gov/etsr/9704ETSR.PDF.

Table 13. Increased Cost for Given Levels of Abatement (Cents/kWh)

Million CO_2 Tons Reduced	Cost Increase for Coal	New Levelized Coal Cost	Cost Increase for Natural Gas	New Levelized Natural Gas Cost
461.8 (1990S, LB)	0.21	4.23	0.58	4.72
500	0.25	4.27	0.64	4.78
587.12 (KPS, LB)	0.36	4.38	0.69	4.83
600	0.38	4.40	0.69	4.83
700	0.50	4.52	0.72	4.86
800	0.64	4.66	0.73	4.87
836.2 (1990S, UB)	0.73	4.75	0.76	4.90
900	0.89	4.91	0.81	4.95
1,000	1.10	5.12	0.82	4.96
1,100	1.28	5.30	0.86	5.00
1184.09 (KPS, UB)	1.54	5.56	0.98	5.12

Both the baseline and new levelized costs for coal (Figure 3) and natural gas (Figure 4) are compared with currently available fuel technologies at various abatement targets. In both cases, coal and natural gas remain competitive at relatively low levels of abatement. Assuming that each technology is pursed with the greatest possible efficiency, the lower bound estimates of levelized costs for each fuel type listed in Table 12 are used in Figures 5 and 6. Comparing levelized costs of coal and natural gas at increasing increments of abatement reveals that some options such as hydroelectric, wind, and geothermal may present cost-effective alternatives to fossil fuels under a CO_2

reduction program. Despite its low levelized cost, municipal solid waste involves combustion, thus releasing CO_2, and therefore may not be a preferable alternative. Ultimately, these findings reveal that pursing non-CO_2 emitting energy technologies will likely be a part of a cost-effective CO_2 mitigation strategy.

Figure 5. Comparison of Abatement and Technology Options for Coal Levelized Costs

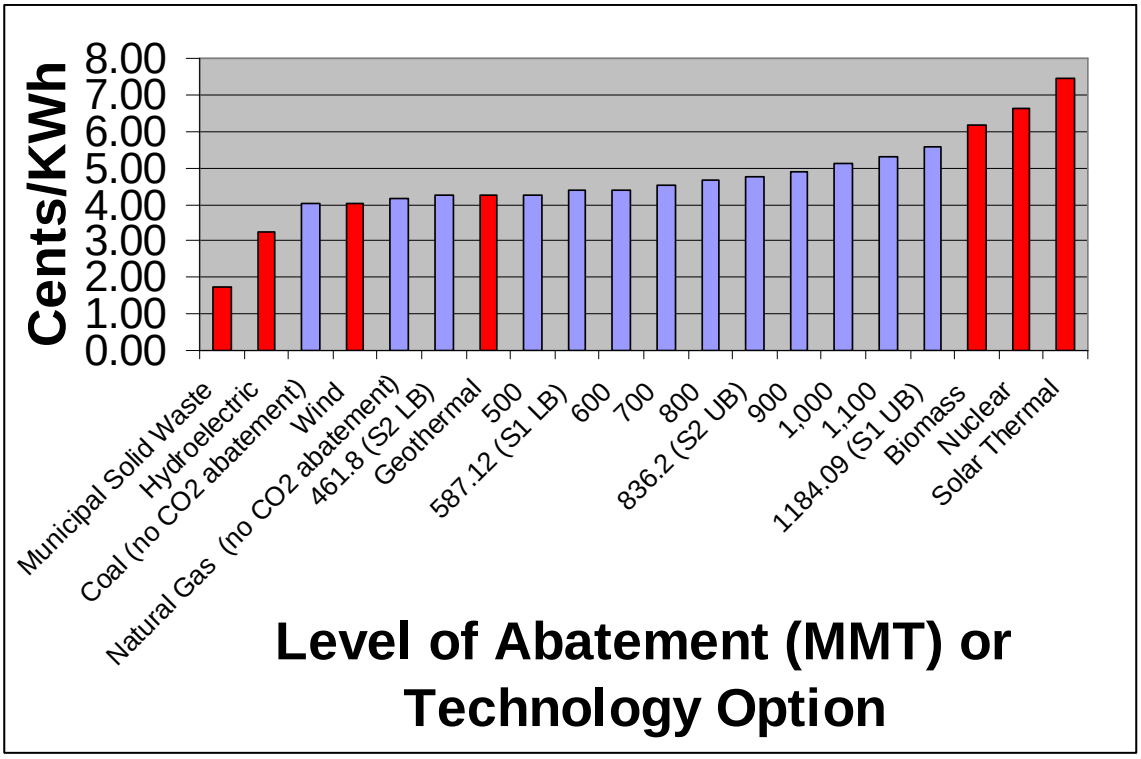


Figure 6. Comparison of Abatement and Technology Options for Natural Gas Levelized Costs

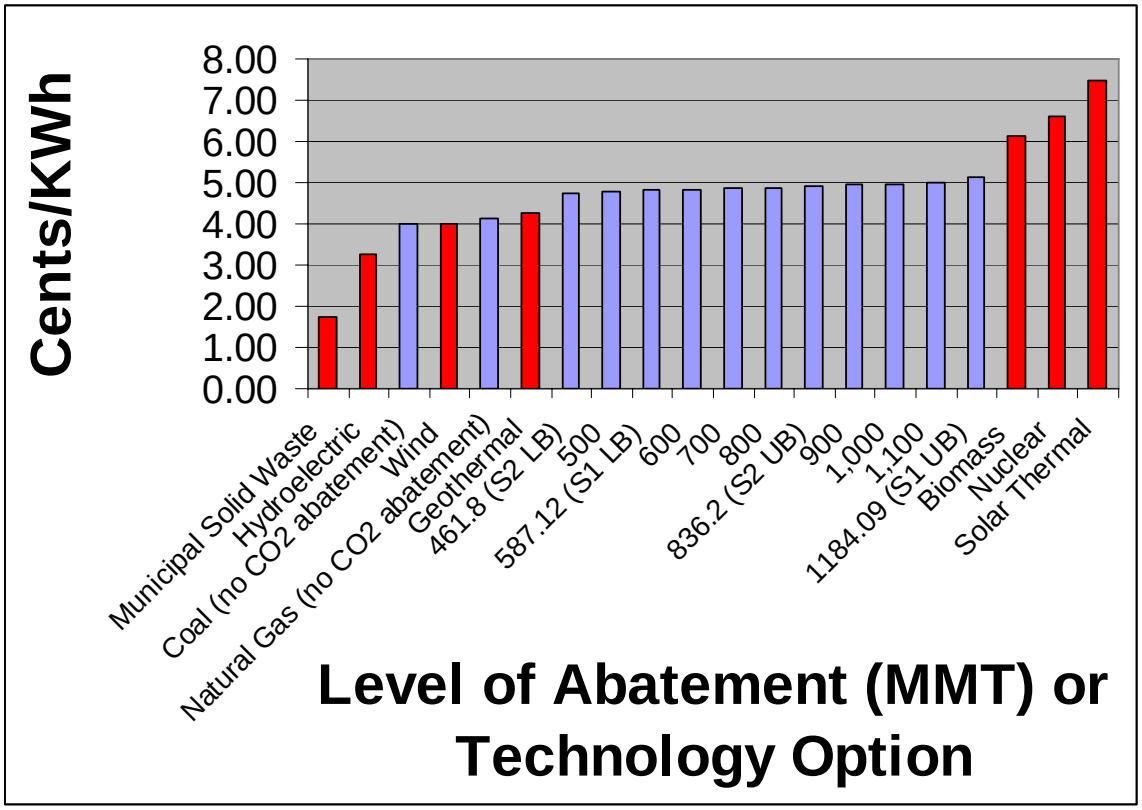
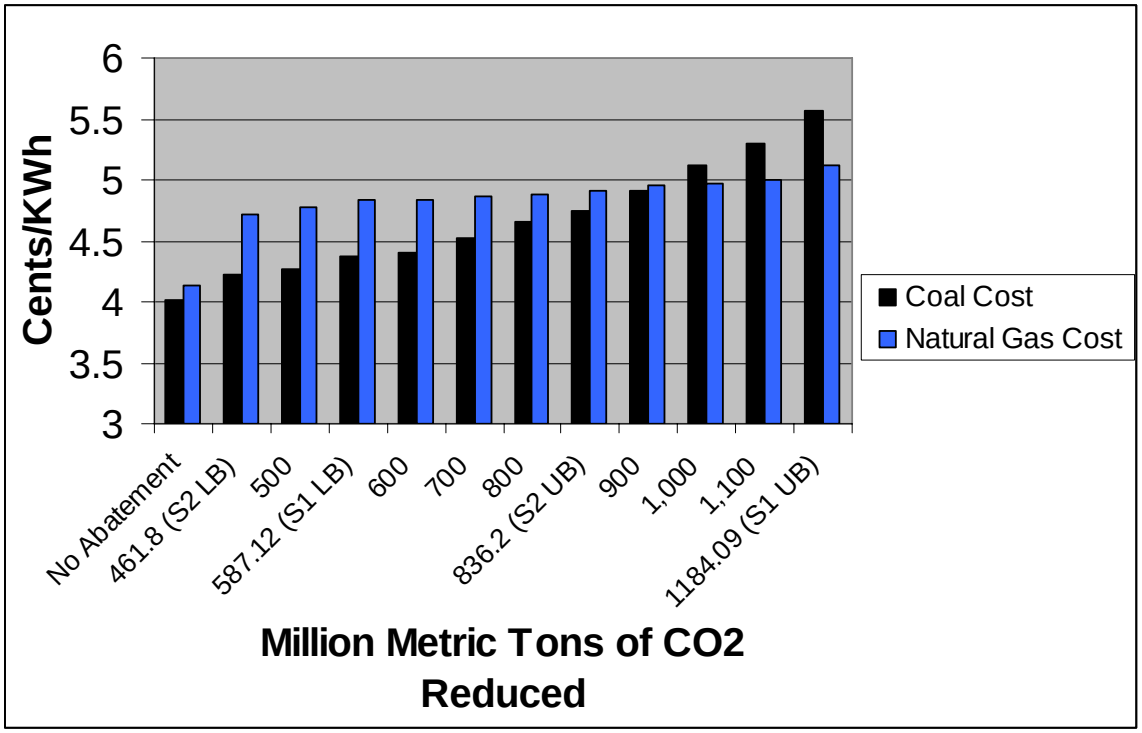


Figure 7 compares increased levelized costs of producing coal and natural gas at increasing levels of CO_2 abatement. For lower levels of abatement, coal remains cheaper per kWh than natural gas. However, for extremely high levels of abatement, particularly as the abatement target approaches the upper bound of Scenario 1, natural gas proves to be cheaper per kWh. Note that since 2000 natural gas fuel prices have increased dramatically, so these results may be different provided more current data. Nevertheless, these results suggest that coal remains a viable energy source compared to natural gas for low to moderate levels of CO_2 abatement despite the significant difference in shadow prices between Groups 2 and 3.

Figure 7. Comparison of Coal and Natural Gas Levelized Costs for Given Levels of CO_2 Abatement



Section 6. Conclusions

In contrast to SO_2, CO_2 is a globally mixing gas. Whereas domestic efforts to reduce SO_2 emissions can have a substantial impact on air quality, domestic efforts to reduce CO_2 emissions will alone not be enough to substantially influence global climate change. Thus, a global CO_2 permit trading market is the optimal policy instrument to curb global climate change, not a national or regional effort. Comparing the shadow prices estimated by this paper with the predicted MAC per ton of CO_2 for Canada, Japan, and Western Europe (though for the year 2010) from the *EIA International Energy Outlook 2005* (Table 1), it appears the U.S. would likely fall somewhere in between

Canada and Western Europe. Still, even in an international market, transactions occur between permit holders and not between countries. Thus, any study attempting to analyze an international CO_2permit market must obtain international data on individual power plants. This data is available, though it usually must be obtained through private companies and is typically quite expensive. Nevertheless, should the U.S. choose to participate in such an international market, an understanding of the marginal abatement cost structures of U.S. electric power plants provides considerable insight into how this market will affect these firms. Moreover, there are sure to be real concerns regarding the national cost of participating in such a program, inviting further discussion on the most cost-effective means of achieving the stated emissions target.

Using a parametric distance function approach, this paper found an average shadow price of 39.97 $/ton for the U.S. electric utility industry, a figure consistent with other calculations of CO_2 shadow prices. These shadow prices were used to construct industry and technology-specific marginal abatement cost curves to determine the costs associated with varying levels of CO_2 reductions. In particular, two potential scenarios were studied. One scenario estimated permit prices and total abatement cost of following the Kyoto Protocol and reducing national CO_2 emissions to 7 percent below 1990 levels. The other estimated a permit price and total abatement cost of reducing national CO_2 emissions to 1990 levels. Under each scenario, an upper bound estimate was generated under the assumption that the electric utility industry would be the sole sector responsible for meeting the targeted reduction. A lower bound estimate was then generated under the assumption that the industry would only be responsible for reducing its proportional share of total CO_2 emissions. It is likely that any effort to reduce domestic CO_2 emissions

would call on the electric utility industry to fall somewhere in between these estimates. Under the Kyoto scenario, a permit price is estimated to be between 30.70 and 48.48 $/ton with a total cost between $10.93 billion and $34.28 billion. Under the 1990 level scenario, a permit price is estimated to be between 27.00 and 37.40 $/ton with a total cost between $7.28 billion and $18.74 billion. Incremental permit prices and total average costs were subsequently estimated between these values.

Behavioral responses of different types of plants were also considered given varying shadow prices between technological groups. The results reveal that plants employing mostly natural gas generating units will likely benefit the most from a permit trading program, or at least would incur the least costs, as they have significantly lower abatement costs than plants that primarily rely on coal or rely on both coal and natural gas. This is likely a result of the fuel since natural gas contains about 45 percent less carbon per unit of energy than coal. Also, coal and natural gas appear to have similar input costs per unit of electricity. Thus, fuel switching could prove to be a significant component of a CO_2 emissions reduction strategy. Further research may provide valuable insight into how large of a role fuel switching may play in meeting CO_2 emissions reductions targets, particularly since natural gas prices have increased substantially since 2000.

Indeed, given the relatively small number of studies focusing on CO_2 shadow prices, benefits from further research may potentially be substantial. For example, with Group 3 plants only composing a small portion of overall net generation and CO_2 emissions, and with this group being most likely to sell permits to plants in other groups, the overall impact that Group 3 permits could have on the overall market is not well

understood. In addition, the marginal abatement costs curves constructed for this paper only offer a lower bound estimate. A more exact industry cost curve would provide more precise information on potential costs faced by the electric utility industry when reducing CO_2 emissions by a given quantity. Furthermore, this would also allow for a more accurate assessment of cost-effectiveness by fuel type to meet emissions targets.

Finally, the total costs of implementing a CO_2 permit trading program were factored into current electricity fossil fuel prices by type and compared with prices of other fuel types, allowing for a comparison of cost-effectiveness in meeting prescribed emissions reduction targets. For lower levels of abatement between the lower and upper bounds of both scenarios, the price of fossil fuel energy is relatively competitive. However, higher levels of abatement suggest that alternative non-emitting energy sources may provide significant cost relief in meeting emissions reduction targets. Still, the exact role alternative energy sources will play in reducing CO_2 emissions is beyond the scope of this paper, but the results suggest there is likely a role to play.

In estimating CO_2 shadow prices for electric power plants in the U.S., this paper lends insight into how a CO_2 permit trading market might take shape in the U.S. and how much total abatement will cost, and suggests that alternative energy sources can likely reduce the overall costs of a large-scale abatement strategy. Specifically, the estimated shadow price for each plant allows for the estimation of total costs, prediction of plant behavior under a CO_2 market, and comparison with other energy sources for a test of cost-effectiveness. Given a relatively small number of studies on CO_2 shadow prices, this paper provides a good first step in exploring the areas discussed. However, as mentioned above, further research on this hot topic, extending this analysis, will better

enhance the development of a sound national, and perhaps international CO_2 abatement strategy.

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