Least Cost Strategies for Complying with New NOx Emissions Limits

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ABSTRACT

This paper summarizes the recent developments in NOx emission rules, presents a mathematical model for the combined energy and emission markets, and the results of applying the formulated model to the Northeast and Midwest electric power markets. The objectives of developing this model are first, to quantify the costs and benefits of the new NOx regulations in the US. Second, to identify and evaluate compliance options and the impact on various market participants in different parts of the US. Third, to model and analyze the effectiveness of tradable-permits markets in achieving efficient outcomes for environmental emissions markets in competitive electric power market. Insights into generators short-run marginal cost bidding behavior and investment decisions are derived from the mathematical model along with impact on the dynamics of the NOx tradable permits market. Two possible outcome scenarios, an over-compliance and under-compliance, are analyzed and discussed. Finally, an application of the market simulation methodology and emission modeling methodologies to the Northeast and Midwest US markets are presented.

INTRODUCTION

In 1997, the EPA issued the NO_x SIP (State Implementation Plan) Call, which would require 22 states[1] and the District of Columbia in the Eastern U.S to submit plans to address the transport of ozone across state boundaries, primarily targeting utility and industrial boilers. This proposal followed in the footsteps of the Memorandum of Understanding (MOU) in the 12-state Northeast Ozone Transport Region (OTR),[2] where states volunteered to reduce emissions to a level almost as stringent as the SIP Call by 2003, [3] through institution of a cap-and-trade program. Under the SIP Call, each state, including states in the OTR, was assigned a budget for NO_x emissions based on an emission rate of 0.15 lb/MMBtu and projected levels of generation from existing electric generators. The total budget in the 22-state region is 544,000 tons, which represents an average reduction in seasonal NO_x emissions of over 60 percent by 2007. Originally, states were to file compliance plans by September 1999 and demonstrate attainment between 2003-2007. However, the D.C Circuit Court of Appeals ruling in May of 1999 suspended implementation of the SIP Call. In a separate decision, the Court also ruled that the EPA's 8-hour ozone standard, which was the basis for the SIP Call, required further justification and represented a breach of its authority. Finally, on March 3, 2000 the same court largely upheld the SIP Call. The litigation was finally sealed on June 22, when the court denied re-hearing of the March 3rd decision.

The eventual affirmation of the NO_x SIP Call was not without substantial controversy. They in fact indicate that there is a strong need to quantify the costs and benefits of further NO_x controls in the United States. Electricity markets have evolved significantly since the original promulgation of the SIP Call in 1997, and few analyses adequately represent these developments in quantifying the impact of further NO_x regulation.

When generators do eventually comply with the NO_x SIP Call, and assuming states follow the precedent of the NO_x cap-and-trade program in the Northeast, they will have the option of either installing NO_x abatement equipment, purchasing allowances, or some combination thereof. Older coal and oil plants will be forced to either retrofit or retire their plants, since the total tradable number of allowances falls far short of total emissions at existing levels of generation. Generators will have to decide on the most economic path for compliance based on forecasted electricity prices and total operating costs for technology investment, trading, or both. All generators, regardless of their compliance strategy, would alter their bidding behavior in electricity markets due to the existence of an allowance trading market, and therefore electricity market prices are likely to increase overall during summer months. However, generators that opt to invest in abatement technology and generators that choose to buy allowances will have different impact on the electricity market-clearing prices. Thus, it is important to determine the likely set of generators that fall into each category.

This paper focuses on analyzing and quantifying both the market price impacts of the SIP Call, as well as the total investment required by utilities to comply. Given the strong presence of coal and oil units on the margin in the eastern US and the high level of NO_x emissions from coal plants, we expect to see a significant impact on energy market prices in the summer months (during the ozone season). This paper presents and discusses a mathematical formulation of joint optimization of generation dispatch and investment in controls that captures the dynamics of emissions trading and electricity markets. Due to the difficulty in solving such an optimization, an iterative method using traditional production cost modeling is used discussed to determine the expected investment decisions in the marketplace and incorporates these into an electricity production cost model to project market price impacts. The methodology is based on achieving equilibrium between long-term investment costs of abatement technologies and short run operating costs of tradable allowances, assuming efficient and competitive allowance and electricity markets. Then, it presents the results of the analysis, including investment costs and impact on electricity market prices, and finally summarizes the conclusions and implications of this paper.

The analysis concludes that forces of deregulation will assist the goals of NO_x regulation and effectively reduce the investments required to comply with the SIP Call, if states institute cap-and-trade programs based on the guidelines of the initial proposal by the EPA. This paper also shows that the unprecedented entry of new, gas-fired units in the Midwest and the Northeast will force reductions in generation and expected emissions from existing units (assuming low natural gas prices). Northeast markets will see modest impacts in the form of investments in NO_x controls and price increases. The Midwest coal industry is likely to face higher market prices and investment costs, but to a lesser degree than would have been the case in the absence of competition.

MODELING METHODOLOGY

In this paper, we show that deregulation and environmental stringency drive the development of efficient, 'clean', gas-fired generation, and, concomitantly, displace older fossil-fired steam units. The relative contribution of each of these drivers to the outcome is hard to distinguish, but is not as important as recognizing and incorporating them into an analysis that predicts likely market outcomes. The model used in this analysis simulates competitive electricity markets where generators incorporate allowance purchases and sales and capital investment decisions into their energy costs and consequently their energy bids in competitive electricity markets. Thus, this model projects the simultaneous impact of competitive market development and NO_x trading on electricity prices.

The methodology presented below describes how to project investment decisions and describes the nature of the impact of allowance trading on electricity prices.

Economic Assumptions

We model a perfectly competitive generation market where generators bid their real opportunity costs, including fuel, variable O&M, and tradable allowances. We assume efficient tradable allowance markets, i.e., zero transaction costs and a single allowance market across state boundaries, as is proposed in the NO_x SIP Call.[4] We also assume efficient electricity markets with marginal cost bidding, centralized least-cost dispatch and minor barriers to entry into the generation market. The electricity markets are separated based on the current or proposed market structures.[5]

We assume an economic equilibrium is reached when the trading price of allowances settle at the marginal cost of emissions reduction plus a premium for the option of having the flexibility of trading, rather than having to make a permanent, fixed investment (a premium to capture the value of the flexibility inherent in trading - i.e., the avoidance of an irreversible investment decision).

Market Mathematical Model

We model the efficient electricity and tradable allowances market as a single problem with the objective of minimizing the cost of producing electricity and investing in NO_x abatement controls subject to the energy balance constraint and the emission budget constraint. The problem is a multi-year optimization extending over the expected life of control technologies, and commencing at some point in the 2001-2002 timeframe, prior to the initial compliance date of 2003. The problem formulation requires the simplification that all investment decisions are made simultaneously and instantaneously. This assumption is true to the extent that all investments in control technologies will be made by the end of the first ozone season. The requirement of meeting demand at each period is part of the nature of electricity and the high storage costs. The emissions constraint, on the other hand, is a feature of cap-and-trade programs. The generators face an instantaneous demand *Demand (t),* and generation costs of $C_i(g_i(t))$, a potential reduction in their emission rates, E_{ri}**,** and an investment cost function and a variable cost function associated with each reduction, $I_i(E_{ri})$ and $V_i(E_{ri})$, respectively. The generators have to decide on a generation profile and an investment decision. To simplify the analysis, we assume a convex and continuos investment cost function and a linear variable O&M function. We address the impact of our simplifying assumptions on the results of the model and incorporate these in our analysis.

Notation:

$g_i(t)$**:**	Energy generated from unit *i* at time *t*.
$C_i(g_i(t))$:	The generation cost function for unit *i* at time *t*, i.e., cost of fuel and unit's variable operation and maintenance cost.
E_{Ai}:	Actual emission rate for generation unit *i* before any abatement technology addition. We assume the emission rate is fixed and independent of generation.
E_{ri} :	Emission rate reduction achieved by adding an abatement technology.
$V_i(E_{ri})$:	Variable cost associated with reducing emissions from unit *i,* by E_{ri}, we assume this cost to be a linear function of E_{ri}, $V_i(E_{ri}) = K_i E_{ri}$.
$I_i(E_{ri})$:	Fixed operating and capital cost function associated with emissions reductions, E_{ri}, over a period T. We assume this cost to be continuos, convex and monotonically increasing.
$l(t)$:	Shadow price of the energy balance constraint, or energy market-clearing price at time t.
m:	Shadow price of the emissions budget constraint, or market-clearing price of tradable allowances.
$t \in [1, T]$:	T is the set of ozone seasons, from May 1st to September 30th, over the average life expectancy of control technologies.
$i \in [1, N]$:	The set of all generators including optimal (chosen) entry and retirement profile.

The problem is formulated as:

$$\underset{g_i, E_{ri}}{Min} \qquad TotalCost = \sum_{\forall i} \sum_{t=1}^{T} \left[C_i(g_i(t)) + V_i(E_{ri})g_i(t)\right] + I_i(E_{ri}) \qquad \textbf{(1)}$$

Subject to:

$$\sum_{\forall i} g_i(t) = Demand\ (t) \qquad :\text{l} \qquad \textbf{Energy Balance Constraint}$$

$$\sum_{t=1}^{T} \sum_{\forall i} g_i(t)(E_{Ai} - E_{ri}) \le Emission\ Budget \qquad :\text{m} \qquad \textbf{Emissions Budget Constraint}$$

$$g_i(t), E_{ri} \ge 0$$

The Khun-Tucker conditions for the above optimization problem are:

$$l(t) = C_i^{'}(g_i(t)) + m\,(E_{Ai} - E_{ri}) + K_i E_{ri} \qquad \forall i,t \qquad \textbf{(2)}$$

$$I_i^{'}(E_{ri}) + K_i \sum_{t=1}^{T} g_i(\text{t}) = m \sum_{t=1}^{T} g_i(\text{t}) \qquad \forall\, i \qquad \textbf{(3)}$$

$$m \ \ge 0\ ,$$

With complementary constraint:

$$m \quad (\sum_{t=1}^{T} \sum_{\forall i} g_i(t)(E_{Ai} - E_{ri}) - Emission\ Budget) \ = 0 \qquad \textbf{(4)}$$

CASE I (Total emissions at budget)

The complementary conditions of the above optimization of (1) show that if the total emissions are at budget, m is not necessarily zero. In this case, using equations (2) and (3) we can conclude the following market characteristics and interpretations:

- First, the market-clearing price for the tradable allowances is the shadow price of the emission budget constraint, or the system cost reduction achieved by relaxing the emission constraint by one per unit, i.e., m **.**

  Equation (3) can be written as: $m = I_i^{'}(E_{ri}) / \sum_{t=1}^{T} g_i(t) + K_i$

  This equation can be interpreted as follows: the price of the tradable allowance is determined by the incremental cost of investment plus the associated variable operation cost (i.e., capital and variable cost associated with reducing emissions by one per unit, assuming no risk premium). More importantly the tradable allowance price is the technology investment cost divided by total generation plus variable O&M cost of the technology. Thus, the lower the capacity factor of the emissions marginal unit, the higher the tradable allowance price.

- Second, using Equation (2), the market-clearing price of energy will be impacted by environmental regulations, and the increase in market-clearing price value is the cost of used tradable allowances and the variable O&M costs associated with abatement technology. Each generator bid will include, in addition to fuel and O&M costs, the unit emission rate times the tradable allowance market price, and the control technology variable O&M cost.

- Third, Equation (3) can be interpreted to mean that at this equilibrium, for each unit, the total cost of trading is equal to the incremental cost of reducing emissions. This conclusion is a consequence of our assumption that the investment function is continuous. In reality, this function is discrete. Nevertheless, Equation (3) can be used as a guideline for investment. A generating unit should invest in abatement technology only if the cost of technology is less than the cost of buying tradable allowances for all emissions.

- Fourth, m does not vary with time, which rests on the assumption that investments are made simultaneously, at which time the market achieves equilibrium.

Under the above market conditions the market-clearing price of tradable allowances is determined by the marginal cost of technology. The simplified model (1) does not account for other factors in the market, such as the value of flexibility, since it assumes a certain demand and generation units' availability, and ignores long-term market dynamics. The value of flexibility is the option value of avoiding compliance costs when the unit is on an outage or is shutdown (because investments are sunk costs, generators have to pay for capital investments cost even when they are on outage), and/or the value of buying allowances at low prices due to over-compliance (market inefficiencies). Moreover, it limits the options for that unit if the market conditions change unfavorably such that it makes the shutdown decision more expensive. Thus we expect the value of the tradable allowance to be equal to the value of the marginal cost of reducing emissions plus a flexibility premium.

The initial allocation of allowances is irrelevant in an efficient tradable allowances market. Note that the initial allocation was not modeled in our problem formulation. The decisions to generate and to invest or trade are independent of the allocated allowances.

CASE II (Total emissions within budget)

Now we consider the second case, where generators over-invest in abatement technologies and reduce emissions to below the required budget. In this case, the second constraint in not binding, thus the associated lagrangian multiplier should be zero, i.e., $m = 0$. Thus, equations (2) and (3) reduce to:

$$l(t) = C_i^{'}(g_i(t)) + K_i E_{ri} \qquad \textbf{(2a)}$$

$$I_i^{'}(E_{ri}) + K_i \sum_{t=1}^{T} g_i(\mathrm{t}) = 0 \qquad \forall\, i \qquad \textbf{(3a)}$$

Equation (2a) can be interpreted as the market-clearing price of electricity, equal to the marginal production cost plus the variable cost associated with the new abatement technology for the marginal unit. The emission rate reduction E_{ri} can be zero, thus there need not be a variable cost.

However, equation (3a) is troubling because it states that either the variable O&M or the incremental investment cost function should be negative. Clearly this is impossible, which means that over- investment is not a solution to this optimization problem when we force K_i and $I_i^{'}(E_{ri})$ to be positive. This result is a consequence of our simplification of a continuous investment function, which implies that every generation unit will be able invest up to its optimal emissions reduction level such that the budget limit is reached but not exceeded.

The case of over-investment (over compliance) in abatement technology is realistic if we consider the discrete nature of the investment function and the associated economies of scale. In this case, the price of the tradable allowance is determined by the market, the demand and supply, rather than by the incremental cost of abatement technology. The tradable allowance price can be as low as the variable cost of abatement technology in this excess-allowances market. The price will never go below the variable O&M of the abatement technology because generators have incentives to use their emission allowances as long as the allowance price is below the variable O&M of the abatement technology, especially if they cannot bank these allowances (It is important to note that in our analysis we assumed that tradable permits are **not bankable**, which is not a realistic assumption and affects the tradable permits price dynamics). Thus, the tradable allowance market-clearing price has a lower bound of, K_m, or the variable O&M cost of the abatement technology of the marginal unit.

Dynamics of Tradable Allowance Markets

We expect the tradable allowances market to start at a price higher than the marginal cost of abatement technology, due to a limited supply of allowances generated from only those units that are obvious choices for investment. The high price would force further investments, until the price reduces to the marginal cost of abatement. Because of economies of scale, the lumpiness and discrete nature of the investments, we expect over-compliance under which conditions the prices can be either equal or less than the marginal cost of abatement technology. An interesting observation is that as generators increase their investments beyond the required amount, the prices of tradable allowances drop, and units have an incentive to increase emissions until the entire budget is used. It is expected that if generators have tradable allowances they will definitely use them, which means emissions will never be below budget, and the price of tradable allowances will never be zero, but rather between, K_m, the variable O&M cost of the abatement technology of the marginal unit and the incremental cost of reducing emissions. This argument suggests a **time-decreasing** emissions budget as the least-cost approach such that the price of a tradable allowance is always related to cost of emission reduction.

General Market Simulation Methodology

The above model formulation forms the mathematical underpinnings of this analysis, and the basis for understanding the theoretical behavior of the market. For several reasons this cannot be directly implemented. First, the assumption of continuous investment functions is simplistic. Second, model capabilities to solve joint optimization including the investment decision problem are not readily available. Thus, we utilized an iterative approach to reach a solution to the investment decision problem looped over a production cost model called GE MAPS, which solves the least-cost dispatch optimization of the electricity market.[6] The iterative algorithm is presented in the next section. The MAPS model includes a detailed representation of all generation units in the Eastern Interconnect, load forecasts by company, fuel forecast by region and type, and a complete representation of the Eastern Interconnect transmission system.[7] The GE MAPS software dispatches the system to meet load requirements at least cost, subject to transmission and operating constraints such as spinning and stand-by reserves.[8] The program calculates hourly generation and locational market-clearing prices for every generation unit on the system. It replicates the operation of an efficient market with all regulatory, market and structure-specific constraints.

The MAPS model helps us evaluate the short-term profitability and the economics of existing and new generation units. Due to the interdependence of new entry and market prices, we use an iterative approach to determine economic entry and retirements. New units are built until the last unit built is marginal, i.e., given the calculated market-clearing prices for energy and installed capacity, the unit makes enough revenues to recover its total costs at a market-based rate of return on capital. We evaluate the profitability of different generation technologies in a given market and choose to build those that are most profitable. To evaluate unit retirement we compare units' operating margins (energy margin and capacity revenues) against the units' fixed operating costs (FOM).[9] If the operating margins are lower than FOM, the unit is identified as a candidate for shutdown. If the same unit looses money over several years we retire it.

An important piece of our analysis is the evaluation of the status of nuclear units. The economics of nuclear unit operation were analyzed by comparing fixed and variable operating costs on a $/MWh basis to the forecasted locational market-clearing prices. Units with operating costs (fixed and variable) much higher than their revenues are retired; those with a small negative margin are assumed to continue operating under the premise that cost reduction can be achieved. Units other than those that have already announced their retirement were not retired. We assumed nuclear units improve their capacity factors to 85% due to competitive pressures. This assumption has a significant impact on this analysis, since the only limit to nuclear generation is their availability, and any increase in generation reduces overall emissions.

Emissions Modeling

First, we believe holders (and purchasers) of allowances will bid in the value of their allowances into the energy market, since each megawatt (MW) of generation results in an opportunity cost (and/or real cost) of selling (and/or purchasing) an emission allowance. All generators will incorporate the cost of allowances used in the energy costs, independent of the quantity of allowances initially allocated. The allowances cost is the emission rate (before or after emission reduction technology) multiplied by the allowance price.

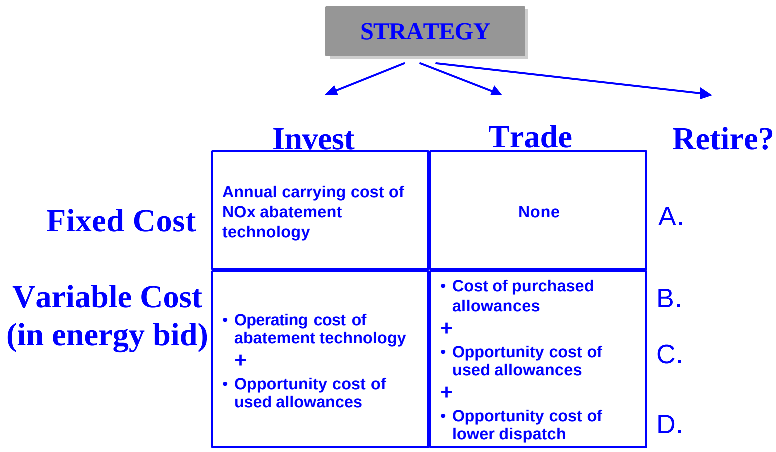
Second, generators' primary response to compliance is either a decision to invest in NO_x control technology, trade at expected allowance prices, or retire. We have developed a methodology to select those plants that would choose to invest rather than trade. We represent the decision-making process as an evaluation and comparison of the costs of compliance and profitability of units under each of the two scenarios (invest vs. trade) using forecasted generation levels and existing emission rates. Qualitatively speaking, generators trade-off between energy margins and allowance costs in one strategy and fixed capital costs in the second compliance strategy. Generators that opt to trade have no incremental fixed costs but have lower energy margins, since their variable costs include the cost or opportunity costs of allowances used, and they dispatch less due to higher marginal costs. On the other hand, generators that invest in control technologies have small decreases in margins due to the variable operating costs of control equipment and low allowances cost, but higher capital costs to recover. Units that cannot recover their fixed operating costs with either strategy are candidates for retirement.

This method leads to the intuitive result that generators with generally high capacity factors (non-marginal) and high emission rates would opt to invest, while those with lower capacity factors or emission rates would opt to trade. Generally, baseload coal plants with few existing controls would find the installation of SCR (selective catalytic reduction) to be the most economic option.

This decision-making analysis is in principle an iterative one, since generators' primary basis for selecting a preferred option is net profitability, but profitability is altered by the investment decision. At the macro level of this analysis, the objective is to ensure that a sufficient number of units invest (in order to simulate a market that complies with the regulations) and to select a reasonable set of candidates for investment. We have developed the following approach to the decision-making process.

The proposed approach involves a cost-based, generator-specific decision-making process based on an estimate of performance level and costs of compliance and the mathematical problem formulation outlined earlier. The iteration begins with a model run with an assumption of no environmental costs on the part of all generators, leading to a first estimate of performance (generation, revenues, and costs). For each generation unit a comparison of the annualized cost of compliance is made to decide whether to invest or trade. The comparison includes the components shown in Figure 1a.

FIGURE 1A – INVESTMENT DECISION CRITERIA



The set of investment decisions at each iteration is used to determine the set of units that decide to invest in technology and the type of technology selected. The associated fixed and variable O&M costs for these units are incorporated into the dispatch model, and a new run is made to determine the new performance levels for the next iteration. This process continues until successive iterations yield emissions within the cap for a given allowance price, which represents the projected equilibrium NO_x trading price. An example of this investment decision criterion is shown in Figure1b.

Figure 1b – Investment Decision - Example[10]

Plant	Type	2003 Cap Factor	NOx Rate (lb/MMBtu)	Target Rate (lb/MMBtu)	Percent Reduction Required	Compliance Technology	Compliance Cost $/MW-yr (Invest)	Compliance Cost $/MW-yr (Trade)	Decision
Base Load Unit	Coal	91%	0.38	0.15	61%	SCR	$ 20,350.2	$ 39,009.4	INVEST
Peaker	Oil	5%	0.39	0.15	62%	SCR	$ 5,124.5	$ 2,164.1	TRADE

The algorithm for this iterative process can be summarized as follows:

1. Start with least cost dispatch ignoring environmental costs, determine units' generation, revenues and costs.
2. Select a projected equilibrium trading allowance price, and compare the cost of trading to the cost of investing (evaluate different technologies), given the performance level assumed in 1. Choose the option that results in lower costs for each evaluated unit.
3. For those units that opted to invest, add the variable O&M of the selected technology to their generation bid. For all units add the emission opportunity costs as the tradable allowance price times their emission rate (either original or post-investment).
4. Solve for least-cost dispatch with the new unit marginal costs, determine units' generation, revenues and costs, and total NO_x emissions.
5. Check to see if total emissions are within budget. If yes, stop iterations, if no, go back to 2 (increasing the projected equilibrium allowance price).

This approach yields accurate results and is the basis for our results and conclusions presented in the next section. It reaches a system-wide equilibrium when it is not economic for any additional generating unit to switch investment/trade decision, given forecasted electricity market-clearing price and the projected allowance trading price, and when the total emissions are at or below the required emissions budget. The iterative approach converges mainly because for most baseload and peaking units the decision is clear; baseload units should invest and peakers should trade. For the intermediate units the decision is not so clear but there are a limited number of options at each iteration, that is either do not invest or invest in one of four or five technologies. This means that the algorithm reaches a solution in a small number of iterations.

The projected allowance price should reflect all the information on the cost of the marginal investment technology, capacity factor, emission rate for the marginal unit and the market premium associated with trading, assuming the NO_x allowance market is efficient. Futures-market prices for NO_x allowances were used as a starting point in this analysis. We found that the market-clearing price for allowances in ECAR significantly exceeds the incremental emission reduction cost, indicating a low capacity factor for the emissions marginal unit.

IMPLICATIONS AND CONCLUSIONS

This paper presents tools and well-defined methodologies to analyze the cost of further NO_x regulation, if implemented as market-based cap-and-trade programs, on the electricity industry, taking into account competitive trends in the marketplace. The industry can use these analytical tools to make informed policy decisions based on cost-benefit analyses and thereby reduce ambiguity and misunderstandings associated with EPA NO_x regulations. These analyses can also be used to evaluate market price impacts of NO_x regulations on asset value and help generators' choose the least cost compliance strategy.

This paper develops a mathematical formulation of the incorporation of allowance markets into electricity production cost modeling. The resulting formulation requires either a joint optimization of generation dispatch and investments in abatement technology, or an iterative approach wrapped around traditional production cost models. The paper proposes a methodology to analyze and estimate investment decisions on the part of generators in response to the NO_x SIP Call.

We applied the above methodology to the Northeast and Midwest electricity markets and analyzed the generators behavior under emissions trading and projected market prices under these conditions. The impact of the NO_x SIP Call on market prices on an annual basis can be up to 5% in PJM and up to 15% in some parts of ECAR and MAIN. This implies an even higher increase during the summer months. However, the wave of new entry will likely counter this and lead to an overall reduction in prices relative to today.

The establishment of competitive markets across the Eastern US and the subsequent entry of substantial amounts of new gas-fired capacity are likely to render the NOx SIP Call less stringent than originally envisioned. Improvement in the performance and generation of the nuclear industry due to these competitive pressures may also contribute to this trend. If the NOx SIP Call does get implemented according to originally proposed guidelines, which had not anticipated levels of competitive entry expected today between 2003 and 2007, less existing fossil units may find investment in abatement technologies a necessary compliance option. EPA's budget and allocation guidelines used, almost comprehensively, a positive growth rate in generation of existing units in the eastern US. Our market simulation results show a lower increase, or, in some cases, a reduction, in generation from a substantial number of units (assuming low natural gas prices).

Conversely, the expectation of further environmental regulation has fostered the growth of competitive entry in the marketplace. Although not explicitly analyzed in the paper, this is an expected result of the projected increases in market prices and retirements. The synergy between competitive trends in the industry and emissions trading found in this paper may also provide a precedent for implementing market-based mechanisms for the regulation of new substances.

References

- EPA NO_x SIP Call Regulatory Impact Assessment, *EPA, 1997.*

- Economic Impact of the NO_x SIP Call on Electric Generation, *Sam Napolitano, EPA, Jan 1999*.

Data Sources:

- EPA's Emission Inventory and the E-GRID database, showing unit and plant heat input, NO_x emissions and emission rates for power plants and boilers.

- Current allowance trading prices in the Northeast and market knowledge and judgement were used to estimate the equilibrium trading value of NO_x allowances [Cantor Fitzgerald, Environmental Brokerage Services].

- NERC Electricity Supply and Demand database, NERC Generator Availability Database System FERC forms 1, 714, 715, and EIA 411.

- NOx control technology costs from EPA's Regulatory Impact Assessment, Appendix 5-Pollution Control Performance and Costs, shown below (1997$).

	Emissions	Plant Type	Capital ($/kW)	FOM ($/kW-yr)	VOM ($/MWh)
SCR (low Nox)	Low	Coal	$ 69.70	$ 6.12	$ 0.24
SCR (High Nox)	High	Coal	$ 71.80	$ 6.38	$ 0.40
SNCR (Low Nox)	Low	Coal	$ 16.60	$ 0.24	$ 0.82
SNCR (High Nox)	High	Coal	$ 14.30	$ 0.22	$ 1.08
SCR	All	Oil/Gas	$ 28.10	$ 0.87	$ 0.10
SNCR	All	Oil/Gas	$ 9.40	$ 0.15	$ 0.44
LNB (no overfire)	All	Coal	$ 16.80	$ 0.25	$ 0.05
LNB (with overfire	All	Coal	$ 22.80	$ 0.35	$ 0.07

- Fuel prices: TCA gas and oil price forecast, Resource Data International Inc. coal price forecast.

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[1] Alabama, Connecticut, District of Columbia, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, Wisconsin, and West Virginia.

[2] The OTR comprises the states of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia.

[3] Phase II of the MOU allocates allowances based on the less stringent of a 75% reduction and a reduction to 0.15lb/MMBtu.

[4] If we relax this assumption we end up with regional markets for NO_x tradable allowances with different prices depending on the marginal technology in each region.

[5] NEPOOL, NYPP, PJM, ECAR, MAIN, MAPP, SPP, SERC and FRCC. See www.nerc.com for a description of these regions.

[6] General Electric's Market Assessment Portfolio Strategy (GE MAPS) model is a security-constrained, least-cost chronological production cost model that simulates competitive electricity markets.

[7] The transmission system representation includes pre- and post-contingency thermal limits on individual transmission lines and transformers, and power flow limits on all major interfaces.

[8] The source of this data is based on public domain information such as FERC 714, 715, and Form 1, EIA 411, Pool & ISO documents and web sites, etc.

[9] Fixed operating and maintenance costs ignore capital costs since these are sunk costs and do not affect the shutdown decision. The abatement technology capital costs that have not yet been made are considered as capital improvements and do affect the shutdown decision.

[10] Note that the simplification made in the investment decision is that the level of investment chosen in each comparison was that level required to achieve an emission rate of 0.15 lb/MMBtu. In a true mathematical optimization, all units would select the optimal level of investment, ranging from 0 (only trade) to 100% (emission-free).