# Electricity Market Distortions Associated With Inconsistent Air Quality Regulations

Prepared for
**The Project for a Sustainable FERC Energy Policy**

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**November 18, 1999**

# Table of Contents

# List of Tables



# List of Figures

## Acknowledgments

The authors would like to thank the following people who provided valuable input to this report. The conclusions and recommendations in this report are those of the authors. The responsibility for any errors in this work also resides with the authors.

Kathleen Bassi, Illinois Environmental Protection Agency

Terry Black, Project for a Sustainable FERC Energy Policy

Joel Bluestein, Energy and Environmental Analysis Inc.

Jim Caldwell, Center for Energy Efficiency and Renewable Resources

Joe Cavicchi, Economic Research Group

Sarah Dunham, US Environmental Protection Agency

Tiffany Elliott, Electric Power Supply Association

Ned Ford, Sierra Club

Janel Guerero, Government Affairs, Enron Corporation

David Hawkins, Natural Resources Defense Council

Geoff Keith, M.J. Bradley & Associates

Rick Morgan, Environmental Protection Agency

Catherine Morris, The Center for Clean Air Policy

Chris Romaine, Illinois Environmental Protection Agency

Kevin Snape, The Nature Conservancy

Bill Spires, Ohio Environmental Protection Agency

Brian Urbachesky, American Lung Association, Illinois Chapter

Dean Van Orden, Pennsylvania Department of Environmental Protection

Kurt Waltzer, Ohio Environmental Council

The authors also wish to express their gratitude to the Energy Foundation and the Center for Energy Efficiency and Renewable Technologies for their financial support.


Additional copies of this report are available from the Synapse website at: www.synapse-energy.com.

# Executive Summary

## Competitive Markets and Potential Distortions

As the electric industry is restructured, and competition is introduced at both the wholesale and retail levels, economic regulators must ensure that the markets being created are sufficiently competitive. These regulators, primarily the Federal Energy Regulatory Commission (FERC) and state public utility commissions, must assess the competitiveness of electricity markets as they adopt restructuring rules and orders, review corporate mergers and acquisitions, review generation assets divestitures, review proposals for Independent System Operators and Regional Transmission Organizations, and consider generation companies' petitions to move from regulated to market-based rates.

In assessing the competitiveness of emerging electricity markets, it is necessary to consider the impact of environmental regulations on the various existing and potential market participants. Many air quality regulations treat existing power plants differently than new power plants seeking to enter the electricity market. In general, existing power plants are subject to less stringent pollution standards than new power plants, and owners of existing power plants are allocated free pollution rights that are not as easily available to new entrants. These differences can create distortions in electricity markets, and can hinder the development of a truly competitive electricity industry.

Market distortions can take various forms. In this study we explore two types of market distortions that might arise from inconsistent air quality regulations: inequities among competitors and market power. Inequities generally occur when environmental regulatory requirements and policies are applied differently to existing and new power plants. Such inequities can provide existing power plants with certain economic advantages. Market power occurs when one or more participants have the ability to affect market prices or restrict entry, as a consequence of a large market share or control over an essential input. Emission allowances and emission offsets are essential inputs for the production of electricity, and can in some cases be used to exercise market power.

These two types of market distortions – inequities and market power – can create or increase barriers to market entry. Regulators and electricity consumers are counting on new entrants in electricity markets to play a key role in furthering competition over time and in moderating electricity price increases. Hence, it is important to acknowledge and assess barriers to entry in any analysis of competitive electricity markets. It is also important to recognize that barriers to entry can have a compounding effect. Some barriers might seem relatively small in and of themselves, but when combined with one or more other barriers they could pose significant threats to competition.

This study focuses on potential market distortions arising from four aspects of environmental regulations facing the electric industry:

- emission standards and control technology requirements imposed by the New Source Review (NSR) provisions of the Clean Air Act;
- emission offset requirements imposed by the NSR provisions;

- the national sulfur dioxide ($SO_2$) cap-and-trade program; and
- regional nitrogen oxide ($NO_X$) cap-and-trade programs.

It is important to note that there are powerful market distortions resulting from the absence of regulations regarding other pollutants. In particular, the current lack of regulations on carbon dioxide ($CO_2$), mercury, and other air toxics provides existing coal-fired generation with a market advantage over competing resources (such as combined-cycle natural gas, renewable resources, end-use efficiency) that have lower emissions of these currently unregulated pollutants. Although the market distortions resulting from the absence of regulations on certain pollutants is beyond the scope of this study, it is important to recognize that they exist in addition to the market distortions discussed here.

## Findings

It is difficult to make generalizations about market distortions arising from inconsistent environmental regulations because of the unique conditions that apply to each power plant. The existence and extent of market distortions will vary according to the federal, regional, state and local regulatory and environmental conditions – as well as local and regional electricity generation and transmission market conditions. Consequently, readers wishing to draw conclusions about a particular plant or region of the country may need to investigate the specific conditions relevant to them. With this important caveat in mind, some general conclusions are summarized below.

***NSR Control Technology Standards***. The NSR emission standard and control technology requirements allow existing sources to operate under less stringent emission standards than new sources. In attainment areas, existing sources do not have any specific control requirements, while new sources are required to install the best available control technology (BACT). In non-attainment areas, existing sources are generally required to install reasonably available control technologies (RACT), while new sources are required to meet the much more stringent lowest achievable emission rate (LAER) standard.

Consequently, existing facilities are allowed avoid costly pollution control technologies and to operate with substantially higher emission rates than new sources. This creates inequities between new and existing sources competing in the same electricity markets. In non-attainment areas, existing sources are allowed to operate with $NO_X$ emission rates that are as much as 25 to 50 times higher than those of new sources. Because of economies of scale, the NSR control technology requirements tend to pose the greatest problem for developers of small generating units, including some combined heat and power applications.

In addition to providing advantages to certain market participants, the inconsistent NSR requirements are not economically efficient. By allowing existing sources to meet less stringent standards, many low-cost $NO_X$ reduction opportunities are not captured, while new sources are forced to obtain some of the most expensive $NO_X$ reductions. Furthermore, the NSR provisions can create economic barriers to some new sources, which slow down the turnover of existing stock, thereby delaying environmental benefits that could be obtained from new, more efficient and cleaner power plants.

***NSR Offsets***. The requirement for new sources in nonattainment areas to obtain offsets is another source of potential market distortions. The NSR offset requirement distributes the burden of preventing air quality degradation inequitably between existing sources and new entrants. Existing sources are generally required to achieve a specific emission rate. New sources are required to achieve a more stringent emission rate *and* to offset their emissions. Thus, new sources are essentially held to a zero emission standard.

To date, the cost of acquiring emission offsets has not been high enough in most regions to restrict market entry, but under certain circumstances problems have emerged. For example, in the San Diego area the small number of existing sources and stringent regulation of these sources has led to a very short supply of emission offsets. The inability of new sources to obtain offsets currently represents a considerable barrier to market entry in that area. As regulations become more stringent and markets become tighter, similar situations could emerge, thus it is important for both economic and environmental regulators to monitor the effect of this requirement on electricity markets.

***$SO_2$ Allowances***. The national $SO_2$ cap-and-trade program is unlikely to create market power problems, for two reasons. First, the $SO_2$ allowance market is national in scope, with millions of allowances allocated annually. This makes it very difficult for any single market participant to influence prices or market entry. Second, annual auctions of allowances set aside for new entrants provide opportunities for new entrants to obtain allowances.

Certain aspects of the $SO_2$ program do, however, create inequities between some market participants. In particular, the allowance allocation scheme provides all of the free $SO_2$ allowances to existing sources – new units are required to purchase allowances. In addition, the allocation of allowances based on heat input essentially rewards power plants for inefficient operation during the baseline years (i.e., the historic years used to determine allowance allocations). Furthermore, the allocation of allowances based on historic plant utilization is inappropriate when current plant utilization differs significantly from historic.

***$NO_X$ Allowances***. Both existing and proposed $NO_X$ cap-and-trade programs will create inequities between owners of new and existing power plants, where these programs do not provide allowances to new sources. In the OTC $NO_X$ Budget program, certain states do not provide allowances for new sources – they allocate all of the free $NO_X$ allowances to existing sources. In its $NO_X$ Budget Trading Program, the EPA has recommended setting aside free $NO_X$ allowances for new sources, however this will ultimately be decided at the state level. Currently, some states have proposed set-asides for new sources while others have not. When insufficient allowances are set aside for new sources, these sources must incur a cost for every ton of pollution they emit, while existing sources incur a cost only for pollution they emit in excess of the effective standard.

Market power in the $NO_X$ allowance market could be a problem if the size of the $NO_X$ allowance trading market is not sufficiently large. If one or more existing firms owned a sufficient share of the power plants in a relevant region, they could manipulate allowance prices and/or interfere with market entry. Existing $NO_X$ allowance programs have a sufficient number of competitors to prevent market power problems, however, the geographic scope of the allowance program to be adopted under EPA's SIP Rule has yet to be determined.

***New Power Plant Developments***. It is important to note that many new power plants are currently being developed to compete in newly restructured electricity markets, despite our findings that inconsistent environmental regulations are likely to create barriers to entry in some circumstances. For example, generation companies have submitted proposals to the PJM-ISO for feasibility studies of over 20,000 MW of new generation capacity, in a region where existing capacity is roughly 60,000 MW. This new power plant activity provides evidence that the barriers to entry discussed in this report do not preclude the development of new resources.

However, this activity does not mean that the barriers do not exist or that they do not have important economic and environmental implications. There still may be inequities that provide competitive advantages to existing power plants. Many questions remain regarding these new power plant developments. Would there be even more proposals for new power plants if these inequities were removed? Would consistent environmental regulations provide new, cleaner generation sources with greater opportunities to displace generation from existing units, or even to force them into retirement? Are there some regions of the country that are likely to see fewer new power plants than other regions because of differing environmental regulations? Will all of the new power plants being proposed and developed be able to remain solvent in a market where they are required to incur higher environmental control costs than their competitors? Will the barriers to entry discussed in this report be more important in those electricity markets that are less profitable than those that have been deregulated to date?

## Options for Mitigating Market Distortions

There is no basis in economic theory for treating new sources differently from existing sources when designing environmental regulations. In fact, grandfathering is often economically inefficient because it provides a competitive advantage to existing industries and firms, thereby hindering new competitors and opportunities for innovation.

The primary justification for applying less stringent regulations to existing polluters is that it is often necessary in order to win political acceptance of the new regulations. Such political favoritism was less problematic during the $SO_2$ debate of the 1980's, because the electricity industry was regulated and there was little concern about introducing and maintaining a workably competitive electricity market.

However, under current industry conditions it is crucial that both environmental and economic regulators work to assure sufficiently competitive electricity markets. If new entrants are not allowed sufficient access to the electricity market, the introduction of newer, more efficient, less polluting generating facilities will be delayed, and the goals of both the environmental regulators and economic regulators will be undermined. The primary options for mitigating or eliminating inconsistencies in environmental regulations are summarized below.

***EPA SIP Rule***. The EPA SIP Rule would eliminate a significant portion of the difference in $NO_X$ regulations that are applied to new versus existing power plants. The SIP Rule emission limit of 0.15 lb/MMBtu is substantially lower than the range of emission rates required of existing coal units under existing regulations. However, even if the SIP Rule is implemented, there will continue to be a large difference between emission requirements of new and existing units. The SIP emission limit is still roughly seven to fifteen times less stringent than typical $NO_X$ emission rates required of new natural gas combined-cycle units in nonattainment areas.

***Allowance Allocation Schemes***. Emission allowance allocation schemes can be designed in ways that ensure that new sources are provided with allowances on a basis that is equitable with existing sources. The key features of such a system include (a) the allocation of allowances on an output-basis, as opposed to an input-basis; (b) frequent updating of allowance allocations, annually if possible; (c) the allocation of allowances to both existing and new power plants, using the same emission rate; and (d) the allocation of allowances to end-use efficiency and renewable resources, using the same emission rate as fossil power plants. Most proposals for generation performance standards (GPS) incorporate these important allowance allocation features.

***New Source Review Modifications***. NSR offset markets can be modified to include additional sources of offsets, thereby reducing the potential for problems with market power and barriers to entry. One option is to find innovative ways to create offsets from mobile or area sources. Another is to facilitate inter-area trading of offsets when emissions from one area can be shown to affect air quality in another area (as is currently allowed in some Northeast states and areas of Texas and Southern California). Another option is to integrate the NSR $NO_X$ offset requirements with the SIP $NO_X$ Budget Trading Program, as is being discussed by the EPA. However, even if these remedies are adopted, NSR will still require significantly less stringent control technologies for existing plants than for new ones. In other words, the burden of preventing deterioration in air quality in non-attainment areas will continue to fall more heavily on the cleaner, more efficient new plants. Environmental regulators could revise the NSR control technology requirements so that emission standards are applied equally to both existing and new sources.

***Comparable Standards for All Power Plants***. The most direct way to remove inconsistencies due to environmental regulations is to require all plants to meet the same emission standards. This can be achieved by designing a GPS to replace existing regulations, including the existing NSR provisions. All existing units and new sources would be required to achieve the same output-based emission rate. The emission rate would be determined in such as way as to achieve the desired environmental goals (e.g., the prevention of significant deterioration, the EPA $NO_X$ SIP Rule). Emission allowances would be allocated to all relevant electricity resources, including end-use efficiency and renewable resources, using the same output-based emission standard.

## Recommendations to Economic Regulators

We recommend that economic regulators account for market distortions arising from environmental regulations whenever they assess the competitiveness of electricity markets. Such market distortions can reduce the competitiveness of the relevant electricity market, and might be enough to turn a sufficiently competitive market into one that is not.

For example, FERC's merger policy requires all merger applicants to conduct a market power analysis, including an assessment of market concentrations before and after the merger. According to the FERC merger guidelines, if the concentration analysis indicates that a proposed merger may significantly increase concentration in any of the relevant markets, then FERC should consider other factors that could mitigate or exacerbate market power. Ease of entry into the market is one such factor. Environmental regulations will clearly affect ease of entry, and thus must be considered in any such market power analysis.

There are many instances when economic regulators need to assess the competitiveness of electricity markets. Important examples include (a) reviewing merger and acquisition applications , (b) reviewing generation asset divestiture proposals, (c) investigating market-based rates, (d) debating whether to introduce retail competition, (e) reviewing proposals for Independent System Operators and Regional Transmission Organizations, and (f) developing "standard offer" mechanisms, "green power" programs, or other policies that depend upon competitive markets. Economic regulators may need to consider different industry structures or regulatory policies in light of the potential market distortions, or they may wish to consider various options to work with environmental regulators to mitigate some of those distortions.

The existence and extent of market distortions caused by inconsistent environmental regulations will vary significantly from one region of the country to another. When assessing the competitiveness of electricity markets in any particular region, federal and state economic regulators should routinely collect and analyze local and regional data regarding emission allowance allocation schemes, control technology requirements, and offset requirements and markets. Particular attention should be given to emission offset requirements in non-attainment areas.

### Recommendations to Environmental Regulators

We recommend that environmental regulators acknowledge the importance of competitive electricity markets when designing and modifying environmental regulations. If inconsistent environmental regulations delay or prohibit the introduction of new, more efficient, cleaner power plants, then the fundamental objectives of the environmental regulations will be undermined.

We recommend that environmental regulators develop comparable standards for all power plants. This can be achieved by designing a GPS to replace existing regulations, including the existing NSR provisions. All existing units and new sources should be required to achieve the same output-based emission rate. The emission rate should be determined in such as way as to achieve the desired environmental goals (e.g., the prevention of significant deterioration, the EPA $NO_X$ SIP Rule). Emission allowances should be allocated to all relevant electricity resources, including end-use efficiency and renewable resources, using the same output-based emission standard.

# 1. Introduction

The electricity industry is currently experiencing rapid changes, with the introduction of retail competition, with mergers and acquisitions, with the divestiture of power plants, and with the introduction of many new power developers and marketers. At the same time, the air quality regulations pertaining to the electricity industry are also evolving, with the establishment of a market for trading $SO_2$ allowances, with proposals for establishing similar markets for $NO_X$, and with regulations being developed for particulate matter, air toxics and potentially $CO_2$.

However, there is often little or no coordination between the economic regulators that are restructuring the electricity industry and the environmental regulators that are introducing new requirements, costs and market mechanisms into the same industry. Existing air quality regulations were fashioned in a time before significant competition was introduced to the electricity industry, and new regulations are sometimes established with little regard for the impact that they might have on the competitive nature of the electricity industry.

Currently, many air quality regulations treat existing power plants differently than new power plants seeking to enter the electricity market. In general, existing power plants are subject to less stringent pollution standards than new power plants, and incumbent utilities are allocated pollution rights that are not as easily available to new entrants. These differences can create distortions in electricity markets, and can hinder the development of a truly competitive electricity industry.

Several important air quality regulations treat existing power plants differently than new entrants to the market. First, existing plants have for the most part been "grandfathered" as amendments to the Clean Air Act have tightened emission standards. Existing facilities were grandfathered under the assumption that they would soon be retired and would be replaced by new facilities that would meet the full requirements of the Clean Air Act. However, many plants well over 30 years old remain in service today, resulting in a delay in the anticipated emission reductions and unanticipated inequities in the newly competitive electricity market. Existing facilities were also grandfathered prior to the National Energy Policy Act of 1992, at a time when electricity markets were not expected to be opened to competition.

Second, existing and proposed "cap-and-trade" programs for reducing industry-wide emissions allocate allowances based on historical plant utilization. This means that companies that have been operating plants are allocated allowances, while new market entrants are not. Finally, in nonattainment areas, new sources are required to offset their emissions by purchasing emission reduction credits from existing sources. In some cases, the majority of these credits are controlled by existing power plants in the area – the potential competitors of the new entrant.

These differences in the treatment of new and existing power plants have important implications – both economic and environmental. First, these differences can create distortions in markets for emission allowances and credits and, perhaps more importantly, in electricity markets. Second, these differences may be slowing the rate at which new, cleaner plants can displace older plants, thereby slowing the rate at which emissions from the electricity industry are reduced.

The purpose of this study is to investigate the extent to which inconsistent air quality regulations create distortions in competitive electricity markets. The primary goal is to inform policy makers about the importance of reviewing the impact of air quality regulations when investigating market power in competitive electricity markets. However, the study will also be useful to state and federal environmental regulators considering ways to minimize market distortions that may arise from air quality regulations.

The study focuses on four specific aspects of air quality regulations affecting the electricity industry:

- emission standards and control technology requirements imposed by the New Source Review provisions of Title I of the Clean Air Act;
- emission offset requirements imposed by the NSR provisions;
- the national sulfur dioxide cap-and-trade program established by Title IV of the Clean Air Act; and
- existing and proposed regional nitrogen oxide cap-and-trade programs.

The study begins with a review of these three regulatory programs. Chapter 3 explores the ways in which these programs can lead to market power in competitive electricity markets. Following this are detailed case studies which shed light on the potential market distortions that can arise in the context of (a) the divestiture of power plants, (b) mergers and acquisitions, and (c) the development of new power plants in a region that is in nonattainment of federal air quality standards. Chapter 7 summarizes several options for mitigating market distortions that may arise from inconsistent environmental regulations, and Chapter 8 presents a summary of our conclusions and recommendations.

# 2. Air Quality Regulations That Affect the Electricity Industry

## 2.1 Introduction

The 1990 Clean Air Act Amendments are the most recent and the most comprehensive in a series of federal clean air laws. The original Clean Air Act was passed in 1963. Amendments in 1970 and 1977 broadened and strengthened the Act considerably, and the 1990 Amendments added a comprehensive air toxics program and the first emission allowance trading program. Titles I and IV of the Clean Air Act (the Act) contain the primary laws applicable to the electric industry.

Title I of the Act provides for the National Ambient Air Quality Standards (NAAQS) for six "criteria" pollutants: $SO_2$, $NO_X$, ozone, carbon monoxide (CO), particulate matter (PM), and lead. The NAAQS are applied uniformly throughout the country, and responsibility for monitoring air quality and meeting the standards lies with states.[1] Areas not meeting NAAQS for a criteria pollutant are designated "nonattainment" areas. Each state is required to submit to EPA a State Implementation Plan (SIP) that outlines a strategy for bringing nonattainment areas into compliance with the law. Once a SIP is approved by EPA, it is legally binding and enforceable by either state or federal authorities.

Title I also includes regulations for new sources of air pollution. These regulations take the form of New Source Performance Standards (NSPS) for specific types of facilities and a federal New Source Review program. The 1970 Amendments directed EPA to establish NSPS for selected types of large stationary sources. In 1971 the Agency promulgated NSPS for steam electric generators with an electrical capacity of 100 MW or greater. These standards were revised in 1978, pursuant to the Amendments of 1977. In addition, EPA recently issued new NSPS for $NO_x$ emissions from new and modified utility (and industrial) boilers.[2]

The 1977 Amendments also established the NSR process, which allows standards for new sources to evolve along with advancing technology and which applies different standards in attainment and nonattainment areas. New sources in nonattainment areas are required to install state-of-the-art emission control technology and to obtain offsets for all emissions. Offsets, discussed further below, are one of the two tradable emission currencies that are a key focus of this paper.

1 Some areas of the country, with severe air quality problems, have established local ambient air quality standards more stringent than the NAAQS.

2 In November of 1998 EPA's revised NSPS for $NO_X$ emissions from utility and industrial boilers became effective. The new rule will affect boilers at which construction, modification or reconstruction is commenced after July 9, 1997. For new utility boilers, the standard is 1.6 lb/MWh gross energy output; major modifications trigger a standard of 0.15 lb/MMBtu heat input. The move to an output-based standard for new plants is significant, and may become a model for future regulations (See Section 7).

The 1990 Amendments established the Acid Rain Program, in Title IV of the Act. The program is designed to reduce annual $SO_2$ emissions by 10 million tons (to roughly 1980 levels). Central to the program is the $SO_2$ cap and trade system, which allocates tradable $SO_2$ allowances to the affected plants. The Acid Rain Program also addresses $NO_X$ emissions, by imposing $NO_X$ emission standards on exiting coal facilities. The program is being implemented in two phases: Phase I began in January of 1995, and Phase II will begin in January of 2000.

In addition to the Acid Rain Program, there are two regional allowance programs in the US, one in the Northeast and the other in Southern California. In the Northeast, the Ozone Transport Commission (OTC) was established in 1994. States in the OTC have developed a regional strategy for controlling emissions of ozone precursors, and a $NO_X$ cap and trade program is central to this strategy. In Southern California, a $NO_X$ and $SO_2$ allowance program has been established in the South Coast Air Quality Management District. The allowance program, called the RECLAIM program, commenced in 1994 and applies to all sources that emit at least four tons per year of either $NO_X$ or $SO_2$.

Finally, a large-scale NOx allowance trading program would be implemented across the eastern US as a result of EPA's $NO_X$ SIP Rule. In September of 1998, EPA promulgated a rule requiring the 22 eastern-most states to submit revised SIPs that would achieve additional reductions in $NO_X$ emissions. The rule establishes $NO_x$ budgets for the affected states and rules for compliance.

Each of these allowance programs, as well as the requirements for NSR offsets, are described in more detail below.

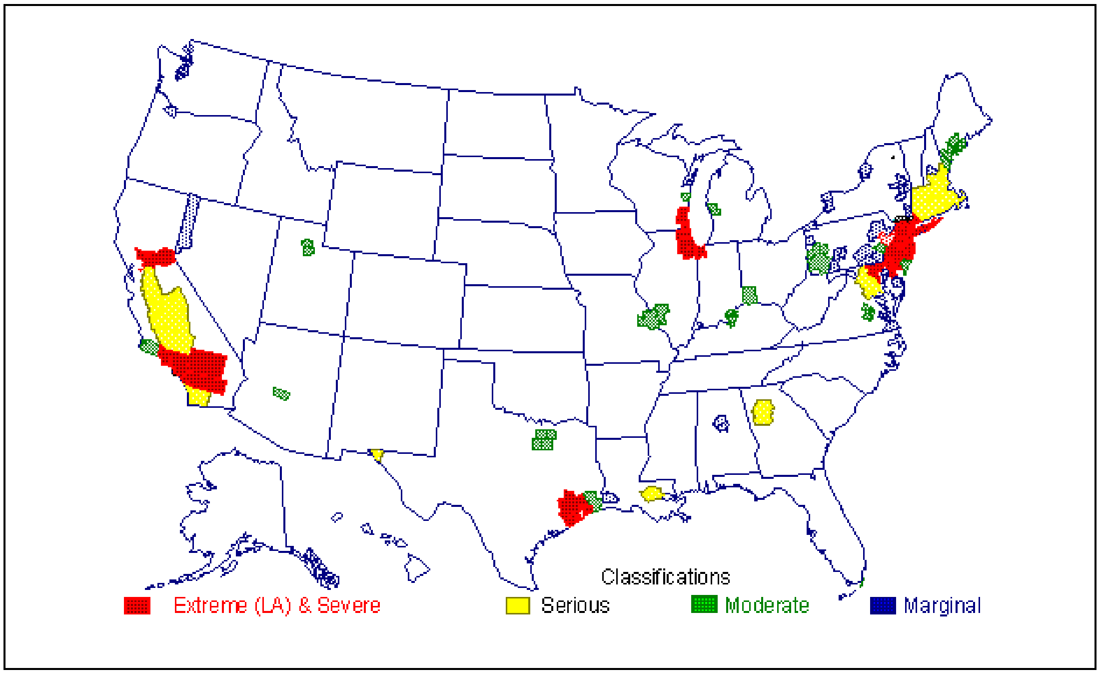
## 2.2 New Source Review and Emission Offsets

All areas of the US are currently classified as being in either attainment or nonattainment of the NAAQS for each of the criteria pollutants. Although much progress in improving air quality has been made over the past three decades, a number of areas in the country remain in nonattainment for one or more pollutants. Nonattainment of the ozone standard is most widespread. The ozone nonattainment areas, as classified in 1997, are shown in Figure 2.1.

In response to mounting evidence of human health and ecosystem impacts of ozone, EPA revised the NAAQS for ozone in 1997. The new NAAQS require that air quality be measured over an eight-hour period, as opposed the previous NAAQS that was limited to a one-hour measurement period. The new NAAQS also establish a more stringent standard than the previous one. During the next several years, the attainment status of many areas of the country will be reclassified, enlarging many existing nonattainment areas for ozone and adding new ones.[3]

[3] On May 14, 1999, the US Court of Appeals for the D.C. Circuit remanded the new primary and secondary NAAQS for ozone and particulates in *American Trucking Association v. EPA*. The Court ruled that EPA had used its authority in violation of the non-delegation doctrine of the Constitution in setting the new standards. The Court remanded the regulations to EPA to extract a "determinate

**Figure 2.1 1997 Ozone Nonattainment Areas.**




The NSR program determines technology-based standards, on a case-by-case basis for "major" new facilities and "major modifications" to existing facilities. The technology-based standards are intended to be revised periodically, and to evolve to become more and more stringent as control technologies become more effective and efficient over time.

In attainment areas, the NSR standards are designed to "prevent significant deterioration" (PSD) of the area's air quality. Major new sources are required to utilize the "best available control technology" (BACT), as determined by EPA, and to model local air quality to demonstrate that the additional emissions will not significantly impact air quality.[4] PSD provisions do not generally require existing sources to reduce emissions in attainment areas.

In nonattainment areas, the NSR rules are more stringent. Existing sources are required to utilize "reasonably available control technologies" (RACT).[5] Major new sources are required to utilize the "lowest achievable emission rate" technology (LAER) and to obtain offsets for any residual emissions.[6] Offsets are units of reduced emissions (denominated in tons per year) obtainable from (a) existing sources that have reduced

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standard" that corrects the non-delegation problem. The EPA is currently developing its response to the court remand.

[4] BACT is generally held to be the lowest emission rate that can be achieved at a reasonable cost.

[5] RACT is defined as the control technology that is reasonably available considering technological and economic feasibility.

[6] LAER is generally held to be the most stringent proven emission control technology available; consideration of costs is expressly forbidden in determining LAER.

their emissions below all applicable requirements, or (b) facilities that are shut down before the end of their useful lives. Subject to certain limitations, NSR offsets can be traded or "banked" for future use.

The 1990 Amendments established more stringent offset provisions for major new sources in nonattainment areas. As shown in Table 2.1, the definition of a major source is dependent on the nonattainment status of the area in question and the size of the source in terms of its potential to emit either $NO_X$ or VOCs. Table 2.1 shows that offset ratios are greater than one-to-one – for every ton of pollution a new source emits in a nonattainment area, the owner must reduce more than one ton of the same pollutant in the same, or a nearby, area.

**Table 2.1 Major Source Definitions and Offset Ratios.**

| Nonattainment Status | Size of Major Source (Tons $NO_X$ or VOC Per Year) | Offset Ratio |
|---|---|---|
| Marginal | 100 | 1 : 1.10 |
| Moderate | 100 | 1 : 1.15 |
| Serious | 50 | 1 : 1.20 |
| Severe | 25 | 1 : 1.30 |
| Extreme | 10 | 1 : 1.50 |

The purpose of requiring offsets is to ensure that new sources in nonattainment areas do not degrade air quality, pushing the area further from attainment. This goal dictates several important characteristics of offsets as a currency: the emission reductions associated with offsets must be (a) quantifiable, (b) surplus, (c) permanent and (d) must occur in close proximity to the nonattainment area in which the new source is being built. However, the Clean Air Act provides states with considerable latitude in developing offset rules.

Offsets must be quantifiable using methods laid out by state environmental agencies. While these methods are not the same from state to state, they are in most cases quite similar. Offsets must be generated from "surplus" emission reductions, reductions achieved beyond the most stringent applicable standard. Thus, in all states, the most stringent emission standard applicable to a facility is used as the baseline from which surplus reductions are measured and offsets are created. The limiting standard could be a federal, state or local standard. All other things being equal, the more stringent the emission standards are in an area, the more difficult it is to create offsets and thus to site major sources or make major modifications to existing sources.

Offsets must also be "permanent," they must represent an enforceable stream of emission reductions extending into the future. This permanence can be achieved by the seller of offsets with either a revised operating permit or with closure of the facility. In both cases, the seller is ensuring that the emission reduction will continue into the future. However, many states treat offsets created by "overcontrol" differently from offsets created by plant shutdowns. Connecticut and Maine, for example, allow the interstate trade of offsets created by plant shutdowns, while the District of Columbia and New Jersey do not. Additionally, some states require the retirement of a certain percentage of offsets when they are created or sold, and in some states more offsets must be retired from plant shutdowns than from overcontrol. The regulatory treatment of offsets from plant shutdowns affects both the price and availability of offsets in many nonattainment areas.

Finally, the facility creating offsets and the new facility using the offsets must be located such that the emission reduction benefits the nonattainment area in which the new source is located. To ensure this outcome, states have developed distance and directionality constraints on the sale of offsets. These constraints require that the seller be within a stated distance from the buyer and that the seller be "upwind" of the buyer, based on predominant weather patterns. Each state has established its own distance and directionality constraints.

In the Northeast, where states are relatively small and nonattainment areas are large, many states have established "memoranda of understanding" (MOUs) enabling offsets to be traded across state lines as long as distance and directionality constraints are met. (States with MOUs are shown in Table 3.2, in Chapter 3.) These MOUs expand the geographic area over which offsets can be created for use in a given area, and thereby increase the number of potential sellers in the offset market.

Table 2.2 shows offset prices as of October 1999 in several areas where active markets have developed to date. Offset prices in an area depend on many factors, including (a) the nonattainment status of an area and the existing emission standards, (b), the existing power plants and other industrial sources from which offsets can be generated, and (c) the level of economic growth in the area and the resulting demand for new power plants and other facilities.

Note that prices in Table 2.2 are listed in terms of Emission Reduction Credits (ERCs). ERCs are an emission currency distinct from NSR offsets, but they are closely related and the terms are often used synonymously. Like offsets, ERCs are created by a permanent, enforceable, surplus reduction in emissions. Also like offsets, in order to create ERCs companies must either revise an operating permit or permanently close a facility. The key difference between ERCs and offsets is that ERC trading is not linked to the development or modification of facilities in nonattainment areas. The purpose of ERC trading is to give regulated sources a compliance option in addition to reducing onsite emissions.

Thus, in a nonattainment area that also has an ERC trading program (like those in Texas), offsets and ERCs are virtually the same thing. However, offsets can be created and traded in a state without an ERC program, and ERCs can be created and traded in attainment areas (where offsets are not required for new or modified sources). Throughout this paper we use the term "offset" to refer to a permanent, enforceable stream of emission reductions acquired for the purpose of compliance with NSR requirements.

**Table 2.2 Offset Prices in Selected Areas, October 1999.**

| State | ERC/Offset Price ($/ton per year) NOx | VOCs |
|---|---|---|
| California | | |
| SCAQMD (LA area)[7] | $22,500 | $3,875 |
| SDAPCD (San Diego area) | ** | ** |
| Connecticut | | |
| Serious Nonattainment | $6,000 | ----- |
| Severe Nonattainment | $5,100 | ----- |
| Maryland | ----- | $2,500 |
| Massachusetts | $6,150 | $3,000 |
| New Jersey | | |
| Plant Shutdown | $450 | $340 |
| Non-Shutdown | $5,100 | $800 |
| New York/Pennsylvania | | |
| Severe Nonattainment | $5,000 | $1,850 |
| Moderate Nonattainment | $2,000 | $1,850 |
| Texas | | |
| Houston/Galveston | $4,325 | $2,700 |
| Beaumont/Port Arthur | $3,233 | $2,750 |
| Dallas/Fort Worth | $5,000 | $1,500 |

*Sources: Cantor Fitzgerald Environmental Brokerage Services, San Diego Air Pollution Control District.*
***Trading is not robust enough in this area to provide reliable prices.*

## 2.3 The $SO_2$ Cap and Trade Program

The Acid Rain Program targeted the largest electric industry sources of $SO_2$ first. The 1990 law named 261 generating units at 111 plants in Eastern and Midwestern states to be regulated in Phase I. Units affected in Phase I were required to hold an allowance for each ton of $SO_2$ emitted in each year beginning in 1995. In the year 2000, Phase II of the program will affect all fossil-fueled power plants larger than 25 MW. Under Phase II, power plant emissions of $SO_2$ will be capped at 8.9 million tons per year, with eight million allowances to be allotted annually and 0.9 million held in reserves and allotted as bonus allowances.

Allowances for $SO_2$ are allocated based in part on historical activity levels. In Phase I, each affected unit receives allowances equal to the unit's historic (average) annual heat input (in lb/MMBtu) multiplied by the $SO_2$ emission rate of 2.5 lbs/MMBtu. At the end of each year, affected sources are required to report their actual $SO_2$ emissions for the year and to hold $SO_2$ allowances equal to their emissions. Since $SO_2$ emissions can affect extremely distant areas, $SO_2$ allowances can be traded and used anywhere within the 48 contiguous US states.

[7] Offsets in the SCAQMD are unique in that they are denominated in pounds per day and do not represent a permanent stream of reductions. The numbers shown here are derived by translating current prices to tons per year and multiplying by 30 years. The cost of a 30-year stream has not been discounted because prices are expected to rise in the future. The figures shown here are close to the clearing prices of several recent trades.

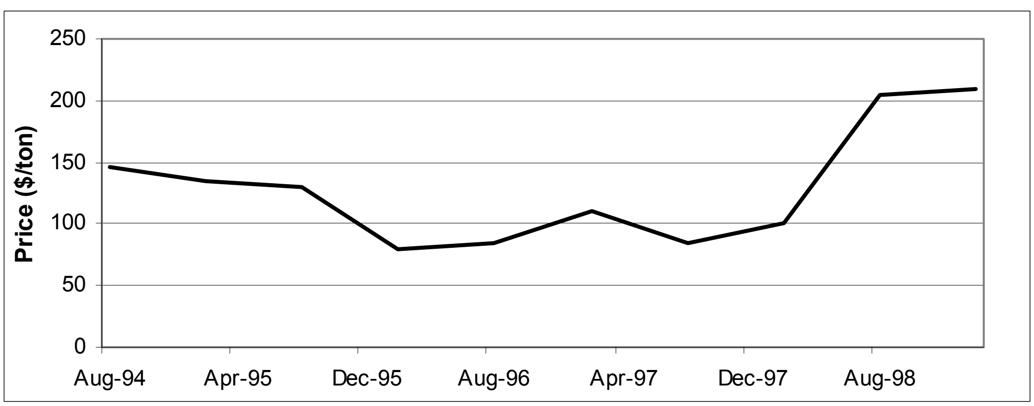
In Phase II, allowances will be allocated such that each plant with a 1985 $SO_2$ emission rate greater than 1.2 lbs/MMBtu will receive enough allowances to emit sulfur dioxide at that rate, based on average heat input between 1985 to 1987. Power plants that had $SO_2$ emission rates lower than 1.2 lb/MMBtu will be allocated enough allowances to maintain their emissions at the 1995 level.

$SO_2$ allowance trading under the Acid Rain Program has been robust. In 1995, each company with an affected unit complied with the program, and 1.9 million allowances were traded, reducing the cost of compliance for some companies significantly. In 1996, trading volume more than doubled, with 4.4 million allowances changing hands and more than half of the affected companies engaging in sales or trades. Trading volume nearly doubled again in 1997 with 7.9 million allowances trading hands.

However, allowance prices have been lower than expected. This is largely because, in calculating where the initial $SO_2$ cap should be set, Congress underestimated the extent to which companies could comply at low cost by switching to lower sulfur coal. This led the Agency to set the cap too high, allocating too many allowances. The result: while EPA was targeting a compliance cost in the range of \$400 to \$1,000 per ton, prices through most of Phase I were in the range of \$80 to \$100. Another factor contributing to the low prices is the fact that many companies chose the more conservative route of reducing emissions onsite rather than relying on a new and untested market.

Allowance prices in early 1999 have been higher – over \$200 per ton – probably due to the impending commencement of Phase II in the year 2000. Figure 2.2 shows the trend in allowance prices during the past four years.

**Figure 2.2 $SO_2$ Allowance Prices, 8/1994 – 2/1999.**




New plants (at which construction began after 1995) must purchase $SO_2$ allowances from either (a) companies holding allowances or (b) from EPA at reserve allowance auctions. In these auctions, 250,000 allowances, or approximately 2.8% of total allowances, are available annually. However, "auctioned" allowances are sold at the administratively determined price of \$1,500 per ton, so it is far cheaper for new entrants to purchase from incumbents.

## 2.4 Title IV $NO_X$ Standards For Existing Sources

Coal-fired sources that are subject to the Title IV Acid Rain Program will be required to meet emission standards for $NO_X$, in addition to complying with the $SO_2$ cap and trade program. Coal boilers are divided into two groups. Group I boilers include dry bottom wall-fired boilers and tangentially-fired boilers. Group II boilers include virtually all other types of coal boilers.

Phase I of the Acid Rain Program requires Group I boilers to meet $NO_X$ emission standards by 1995. Phase II requires that by 2000 Group I boilers meet more stringent standards, and Group II boilers meet $NO_X$ emission standards. These $NO_X$ standards are summarized in Table 2.3.

**Table 2.3 Title IV $NO_X$ Standards for Existing Coal Units**

| Boiler Type | Phase I -- 1995 (lb/MMBtu) | Phase II -- 2000 (lb/MMBtu) | Number of Boilers in US |
|---|---|---|---|
| Dry-bottom wall-fired | 0.50 | 0.46 | 308 |
| Tangential-fired | 0.45 | 0.40 | 299 |
| Cell burners | no standards | 0.68 | 36 |
| Cyclones (>155 MW) | no standards | 0.86 | 55 |
| Wet bottoms (>65 MW) | no standards | 0.84 | 26 |
| Vertically-fired | no standards | 0.80 | 28 |

## 2.5 $NO_x$ Cap and Trade Programs

### The OTC $NO_x$ Budget Program

The 1990 Amendments to the Clean Air Act also mandated the establishment of the Ozone Transport Commission (OTC), to be composed of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, the four northern counties of Virginia and the District of Columbia. While all US states are required to implement certain emission reduction programs in ozone nonattainment areas, OTC states were charged with developing additional regional strategies for controlling emissions of ozone precursors. In September of 1994, the OTC states adopted an MOU to implement a regional "$NO_X$ Budget Program" to reduce $NO_X$ emissions during the ozone season.

The OTC does not have the authority to adopt or enforce regulations; rather the member states implement and enforce regional solutions on a state-by-state basis. In June of 1995, the OTC states agreed on the number of $NO_X$ allowances to be allocated to each state beginning in 1999. States, in turn, allocate allowances to large stationary sources of $NO_X$ – utility and industrial boilers with capacities equal to, or greater than, 250 MMBtu per hour of heat input or with electricity output of 15 MW or greater. As in the Acid Rain Program, sources must hold an allowance for each ton of $NO_X$ emitted, and sources can trade allowances or bank them for future use.

The OTC $NO_X$ Budget Program will require two phases of reductions. Compliance with the first phase began during the ozone season of 1999 (May 1 through September 30), and compliance with the second phase will begin during the ozone season of 2003. In 1990, summer emissions from the affected sources in the OTC totaled 490,741 tons. In 1999, summer $NO_X$ emissions are capped at 290,000 tons. By 2003, this program is expected to reduce summer $NO_X$ emissions from affected sources to 142,874 tons.

Determination of how new sources will acquire OTC $NO_X$ Budget allowances has been made at the state level. Some states are setting aside a specific number of allowances each year for sale or distribution to new sources, while other states will require new sources to obtain allowances in the market. New source set-asides under the OTC $NO_X$ Budget Program are discussed in more detail in Section 3.4.

During most of the period leading to the commencement of the OTC $NO_X$ Budget Program, $NO_X$ allowances traded at prices in the range of $1,000 to $2,000 per ton, consistent with the estimated cost of controls at affected sources. In the spring of 1999 there was a significant increase in the price of allowances, with some trades reportedly occurring at over $7,000 per ton. This price spike was most likely due to last-minute changes in companies' compliance plans and uncertainty over the commencement of the new program. By mid-summer 1999 prices had fallen back to levels below $2,000 per ton.

### Southern California: the RECLAIM Program

The South Coast Air Quality Management District's RECLAIM program has established declining caps for both $NO_X$ and $SO_2$ emissions from large sources in the Los Angeles area. The affected district includes all of Los Angeles County and portions of Orange, Riverside and San Bernadino Counties. Sources affected are those that emit at least four tons per year of one of these pollutants. (Sources emitting more than four tons of only one pollutant are only required to participate in one allowance program.) The RECLAIM program began in 1994, and the $NO_X$ and $SO_2$ caps will decline until 2003. After 2003, sources will receive a stable number of allowances each year into the future. The program will reduce $NO_X$ emissions by 80 percent relative to 1994 levels by the year 2003.[8]

Allowances (actually called "credits" in the RECLAIM program) are allocated based on historical activity levels. The baseline activity level is defined as the average activity level during the years 1989 through 1992. To determine a source's 1994 allocation, all emission standards applicable in 1994 were applied to the baseline activity level. Each source's allocation is declining with the overall cap between 1994 and 2003. No allowances are set aside for new sources; these sources must purchase allowances from existing sources with excess credits.

The absence of a set-aside for new sources represents a market distortion, however the magnitude of this distortion is difficult to assess. The full cost of allowances purchased by new sources cannot be classified as a market distortion, because allowances were not

8 For more information on the RECLAIM program, see the website of SCAQMD, at: "www.aqmd.gov."

free for incumbent firms, as in the Acid Rain Program. Since 1979, new sources in the South Coast region have had to provide NSR offsets for their emissions. Thus, in the case of allowances sold by post-1979 sources, the market distortion is the difference between what the incumbent originally paid to offset emissions and what the new source paid the incumbent for allowances.

To date, sources in operation before the 1979 requirement for NSR offsets have been at a considerable advantage relative to both post-1979 sources and new entrants, because the RECLAIM program has not required significant reductions from many existing sources. Thus, allowances to pre-1979 sources have come at very low cost, while new sources have had to acquire allowances in the market, at higher cost. However, with the reductions required in the year 2000, most RECLAIM sources will have to achieve significant emission reductions.[9] This will increase the effective cost of allowances to existing sources, reducing the inequity between existing and new sources. However, the inequity will persist, as new sources will not be allocated any allowances – they will have to pay for all needed allowances. To date, trading of RECLAIM credits has been robust. In recent years the South Coast Air Quality Management District has consistently registered 600 to 700 trades per year. Currently, $NO_X$ credits for the year 2003 are trading in the range of $2.75 per pound ($5,500 per ton) and $SO_2$ credits are trading in the range of $1.00 per pound ($2,000 per ton). These prices are considerably higher than early RECLAIM prices, and prices are expected to continue increasing as the declining cap forces existing sources to make larger pollution control investments.

### The EPA's $NO_x$ SIP Rule

EPA's $NO_X$ SIP Rule includes a widespread allowance-based trading program. In September of 1998, EPA promulgated a rule requiring 22 states in the eastern US to submit revised SIPs that would achieve additional reductions in $NO_X$ emissions. In the rule, EPA established a $NO_X$ budget for the affected states and rules for compliance.

EPA's $NO_X$ SIP Rule includes a model trading rule for large sources of $NO_X$, but states will have the final authority to design and establish $NO_X$ trading mechanisms. While states will have the flexibility to allocate reductions among the various source categories – e.g., transportation, industry, etc. – power plants are expected to bear the responsibility for major $NO_X$ reductions in most states.

Under EPA's $NO_X$ SIP Rule, $NO_X$ emissions from each of the 22 affected states will be capped during the ozone season (May through September). States must comply with the cap beginning in May of 2003. State caps or "budgets" were developed through detailed analyses of baseline emissions and potential reductions from five source sectors: electricity generating units, other point sources, stationary area sources, on-road mobile sources, and off-road mobile sources.

State budgets for electric generators were developed by applying a $NO_X$ emission rate of 0.15 lb/MMBtu to all fossil-fired turbines and boilers connected to generators 25 MW in size or greater. This emission rate was chosen based on projections of the necessary

[9] Personal communication with SCAQMD staff.

reductions and the cost-effectiveness of various $NO_X$ control options. The EPA determined that this emission rate could be achieved on average across the 22-state region at an average cost of $1,468 per ton removed, assuming a multi-state trading program was adopted.

To allocate allowances to states, EPA developed state budgets for electric generators and four other source categories. For electric generators, the 0.15 lb/MMBtu emission rate was applied to the projected heat input of each large, fossil-fired unit in the state. This allocation method yielded a 22-state ozone season $NO_X$ cap for electric generators of 543,825 tons.

Note that, while EPA derived the total state budgets by developing budgets for each of the five source sectors, states are free to allocate the allowances they receive in any way they choose. Thus, power plants in a given state may actually be allowed to emit more or less than the amount calculated by EPA for allocation purposes, depending on the state's overall compliance strategy.

Each state will develop its own rules determining whether and how new sources will obtain allowances. However, the EPA has recommended a methodology for determining the amount of new source set-asides. EPA has proposed setting aside five percent of the $NO_X$ allowances for new sources for the 2003, 2004, and 2005 control periods. During these control periods, new sources would include all relevant generation units that were installed after May 1995. In subsequent control periods (e.g., 2006), the new source set-asides must be large enough to accommodate any source that commenced operation after May 1 of the control period three years earlier (e.g., 2003). The EPA has proposed a two percent new source set-aside for these subsequent control periods. All set-asides would be issued to new sources free of charge on a first-come, first-served basis. Allowances that are not issued to new sources in the applicable control period will be returned to the existing sources on a pro-rata basis.

The EPA notes that new source set-asides should be large enough to provide all new sources with allowances, and that new sources should be provided with allowances on the same basis as existing units. The EPA also notes that states may have different circumstances that require deviations from its model rule, that its proposal should be seen as the "minimum requirement," and that states may want to consider a larger set-aside (EPA 10/1998).

As promulgated, EPA's SIP Rule requires states to submit revised SIPs by September of 1999. However, in May of 1999 the Court of Appeals for the D.C. Circuit granted the motion of eight petitioning states to stay the submission of revised SIPs pending further order of the court. The court based its decision not on the merits of the science, but in order to allow the parties involved to argue the case before the court. This partial stay will prevent the EPA from implementing the $NO_x$ SIP Rule until the final ruling on this case. During the summer of 1999, negotiations took place around several competing settlement proposals. However, EPA and the states involved in these negotiations could not reach agreement on a settlement, and parties are now focusing on the impending hearings.

If the SIP Rule allowance program is implemented as proposed, it would supersede or fit together with the OTC $NO_X$ Budget Program. Multiple $NO_x$ allowance programs would not be established in the same region.

### Section 126 Petitions to the EPA

In 1997 eight northeastern states filed petitions with the EPA regarding the transport of $NO_X$ and ozone from upwind states, pursuant to Section 126 of the Clean Air Act. The states claim that a group of electricity power plants in the Midwest produce $NO_X$ emissions that significantly contribute to the ozone problem in their states and prevent them from attaining the ambient air quality standards for ozone. The states claim that the transport of ozone is so extensive that they will not be able to attain ozone standards without substantial reductions in ozone transport from upwind areas.

If the EPA determines that an upwind source is emitting a pollutant that significantly inhibits another state from reaching attainment, then the source must cease operation within three months, unless the EPA permits it to continue to operate under a plan to reduce emissions as expeditiously as practical. In their petitions, the states are asking the EPA to establish emission limitations for the upwind plants sufficient to prevent them from significantly contributing to ozone levels within the downwind states.

EPA has not acted on the Section 126 Petitions, because the $NO_X$ SIP Rule would address the complaints raised by the petitioners. If the $NO_X$ SIP Rule is abandoned as a consequence of the current court challenge, then the Section 126 Petitions provide a backup option to achieve many of the same goals as the SIP Rule. Many, but not all, of the power plants affected by the SIP Rule would also be affected by the Section 126 Petition. While the Section 126 Petitions do not include a $NO_X$ cap and trade system, if it eventually becomes the alternative to the SIP call, there is a good chance that such a system will be incorporated into it.

# 3. Market Distortions Caused by Inconsistent Air Quality Regulations

## 3.1 Inequities, Market Power and Barriers to Entry

Market distortions can take various forms. In this study, we frequently refer to two types of market distortions. One type arises from "inequities" between competitors. Regulations that apply to some but not all market participants, or that apply differently to different participants, can create such inequities. The imposition of tighter emissions standards on new generators is an example of this type of market distortion. This sort of inequity does not necessarily involve "market power" – but rather is a matter of the economic playing field being tilted in favor of some participants over others.

Market power is the term we use to refer to the second type of market distortion. It is a more extreme type of distortion that can arise when control of a market is concentrated in a small number of companies. Horizontal market power occurs when a small number of firms control a particular tradable commodity, such as electricity generation or emission allowances. Vertical market power occurs when a small number of firms control an input to a market, or control an "essential facility" required by a market.

FERC and the Department of Justice have developed analytical approaches that can be applied to assess horizontal market power (in terms of concentration of ownership), and these have been applied by regulators in assessing market power concerns in applications for mergers and market-based rates.[10] Similar approaches can and should be applied to markets for emissions rights. In general, however, we are less concerned about the potential for horizontal market power in the markets for allowances and offsets – except in cases where markets are highly constrained (e.g., some offset markets).

A more important concern may arise from the link between emissions and electricity markets, i.e., vertical market power. Specifically, in many electricity markets allowances and offsets represent an "essential input" to the generation of electricity. It is much like fuel supply or transmission access. A generator must have allowances and offsets to cover its air emissions, in the same way that it must have contracts for the delivery of fuel and access to transmission systems. When assessing market power in electricity markets, it is important to recognize the role of emissions rights as an essential facility.

The two main categories of market distortions – inequities and market power – can create or increase barriers to market entry. Regulators and electricity consumers are counting on new entrants in electricity markets to play a key role in furthering competition over time and in moderating electricity price increases. With all other things equal, a market

[10] The Department of Justice and Federal Trade Commission issued revised horizontal merger guidelines in April, 1992 (DOJ and FTC 1992). The FERC subsequently adopted those guidelines as the "basic framework for evaluating the competitive effects of proposed mergers" in its policy statement on merger issues in December 1996 (FERC 1996). Both the DOJ/FTC guidelines and the FERC policy statement identify market entry as one of several factors to be analyzed in determining whether and to what extent a merger is likely to create or enhance market power.

in which entry is likely, timely, and sufficient will be less prone to the abuse of market power. Conversely, where market entry is unlikely, slow, or limited, market power is more of a concern.

It is important to recognize that barriers to entry can have a compounding effect. Some barriers might seem relatively small in and of themselves, but when combined with one or more other barriers they could pose significant threats – or even insurmountable obstacles – to new entrants. Thus, regulators must account for all potential barriers to entry when assessing the competitiveness of electricity markets.

## 3.2 Emission Standards and Control Technology Requirements

### The Disparity in Emission Standards Applied to Existing and New Sources

The Clean Air Act imposes significantly different emission control requirements on new sources relative to existing sources. In attainment areas, existing sources do not have any specific emission control requirements, while new sources must meet PSD standards that require installation of BACT controls. In nonattainment areas, existing sources are generally required to meet the RACT standard, which typically requires low-$NO_X$ combustion controls – e.g., low-$NO_x$ burners (LNB). New sources in nonattainment areas are generally required to meet the much more stringent LAER standard, which typically requires both low-$NO_X$ combustion controls and selective catalytic reduction (SCR) controls.[11]

These different regulations allow existing facilities to operate with emission rates that are substantially higher than new sources. Table 3.1 and Figure 3.1 provide a summary of $NO_X$ emission rates for existing versus new units, under various conditions. The first two lines in Table 3.1 present ranges of 1996 $NO_X$ emission rates of all existing large coal units in the US.[12] The first line presents all those coal units that were on-line in 1975 and earlier, while the second line presents the emission rates of the more recently built units. The newer units have lower emission rates partly as a result of the NSPS, which first began to affect units that went on-line in the mid-1970s.[13]

The third and fourth lines in Table 3.1 present emission standards that existing coal plants are, or will soon be, required to meet. The third line indicates the range of RACT rates that apply to existing coal plants in nonattainment areas. The fourth line indicates the

[11] Steam boilers frequently use LNB as a combustion control, but other options are available. Combustion turbines and combined-cycle units typically use dry low-$NO_X$ technologies as combustion controls. SCR is a post-combustion control, which can be combined with any type of combustion control.

[12] The range presented includes two standard deviations around the 1996 average emission rates. This method eliminates some of the outlier data points. For any distribution of data points, two standard deviations around the average will include at least 75 percent of the observations. For a normal distribution, two standard deviations around the average will include 95.5 percent of the observations. For a detailed presentation of 1996 emission rates, see Table 5.2 of Synapse 6/1998.

[13] The first set of NSPS applied to fossil-fired power plants for which construction commenced after August 1971. These units came on-line shortly thereafter, in the mid-1970s.

$NO_X$ rates that existing coal units will be required to achieve by May 2000, as a consequence of Phase II of the Title IV Acid Rain Program.

Finally, the bottom two lines of Table 3.1 provide the ranges of typical emission rates of new natural gas combined-cycle facilities. The first of these lines presents emission rates for units with low-$NO_X$ combustion controls. The second line presents emission rates for units with both low-$NO_X$ combustion and SCR controls, which are typically required by NSR provisions.

**Table 3.1 Typical $NO_X$ Emission Rates and Standards for Existing and New Facilities**

| | Emission Rate (lb/MMBtu) | Emission Rate (lb/MWh) |
|---|---|---|
| Existing Coal Units in US: | | |
| Average of plants on-line in 1975 and earlier | 0.07 – 1.27 | 0.7 – 12.7 |
| Average of plants on-line after 1975 | 0.14 – 0.70 | 1.4 – 7.0 |
| RACT or state $NO_X$ standards | 0.35 – 1.20 | 3.5 – 12.0 |
| Phase II of Title IV $NO_X$ program, May 2000 | 0.40 – 0.86 | 4.0 – 8.6 |
| EPA $NO_X$ SIP Rule, May 2003 | 0.15 | 1.5 |
| | | |
| New Gas Combined Cycle | | |
| With low-$NO_X$ combustion controls | 0.05 – 0.10 | 0.34 – 0.68 |
| With low-$NO_X$ combustion and SCR controls | 0.01 – 0.02 | 0.07 – 0.14 |

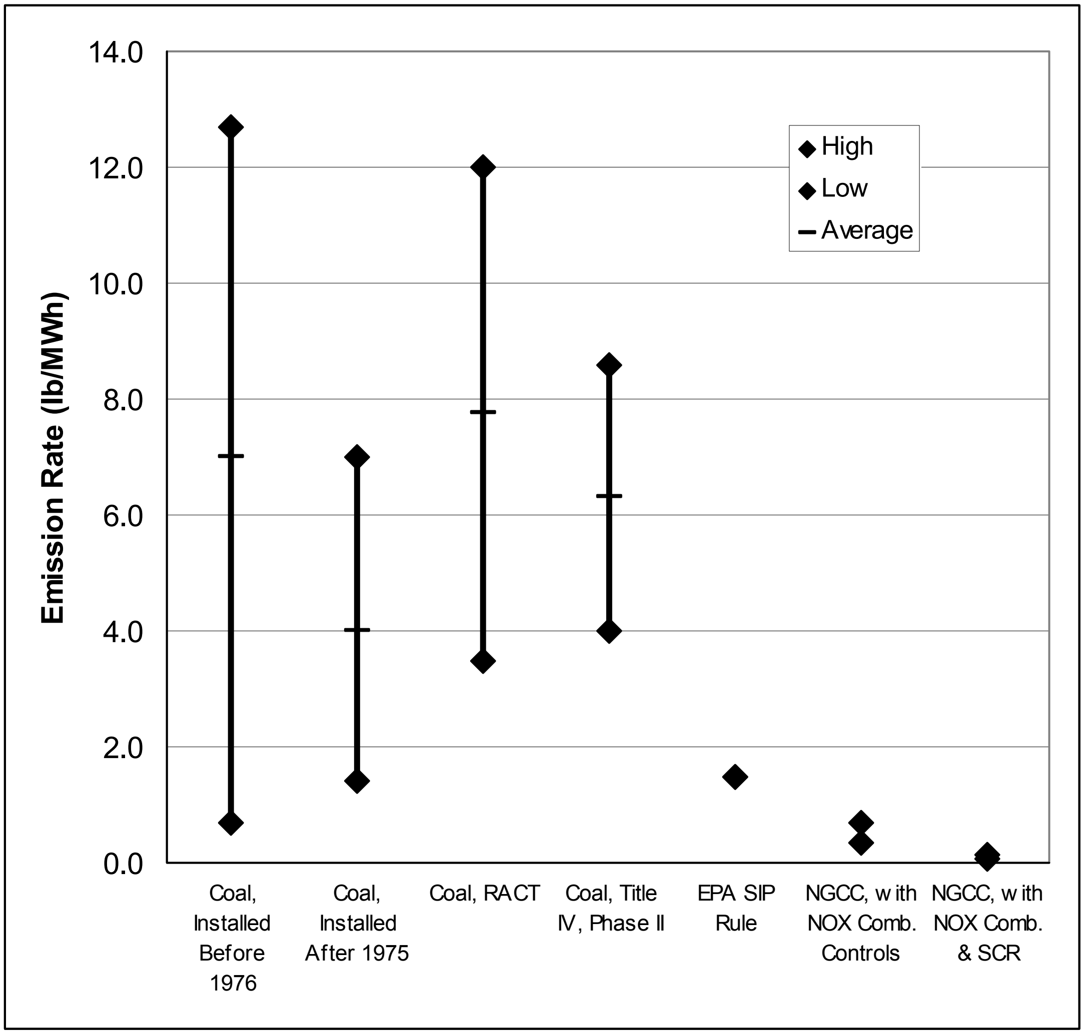
*Notes: Data for existing coal plants taken from Synapse 6/1998. For existing units, RACT rates are from EPA 3/1998; and heat rates are assumed to be 10,000 Btu/kWh. For the gas units, heat rate and emission rates are from EPA 3/1998 and Enron 1999.*

Table 3.1 and Figure 3.1 indicate the large disparity in $NO_X$ emission rate requirements between existing coal and new gas facilities. In 1996, coal plants had average emission rates that were as much as 35 to 70 times higher than new gas units with low-$NO_X$ combustion and SCR controls. Even after existing coal units comply with Phase II of Title IV, there will continue to be a large disparity between emission rates of existing and new units. In nonattainment areas, existing coal units will allowed to emit at levels at least 20 to 40 times higher than new gas sources with low-$NO_X$ combustion and SCR controls.

Figure 3.1 also presents the 0.15 lb/MMBtu emission rate standard used in setting the $NO_X$ budgets for the EPA SIP Rule. Reducing emissions to this level will clearly be an improvement over emission rates required of existing regulations, but will continue to leave a substantial gap between existing units and new units subject to NSR. The SIP Rule standard would allow existing sources to emit $NO_X$ at levels roughly seven to 15 times higher than the emission rates of typical new gas units with low-$NO_X$ combustion and SCR controls.

The disparity in actual emissions is larger than is indicated by the lb/MMBtu rates, because the new gas units are much more efficient than existing coal units. New gas combined-cycle units can operate at roughly 50 to 60 percent efficiency, while existing steam units tend to operate at roughly 34 percent efficiency. As indicated in Table 3.1, when the lb/MWh emission rates are considered, in nonattainment areas existing coal units will be allowed to emit more than 28 to 57 times as much $NO_X$ per unit of electricity generation as new gas units with low-$NO_X$ combustion and SCR controls.

**Figure 3.1 Typical $NO_X$ Emission Rates and Standards for Existing and New Facilities**




*Source: Table 3.1*

## The Economic and Environmental Implications of the Disparity

This large disparity in emission standards is not economically efficient. The NSR provisions that require increasingly stringent emission standards and control technologies for new sources forces the achievement of small emission reductions with high costs, while forgoing many large, lower-cost emission reductions. This inefficiency exists for four reasons.

First, new natural gas sources tend to produce emissions at a rate significantly lower than existing coal units, because of their design, their higher levels of efficiency, and their cleaner fuel choice. Even when uncontrolled, new gas unit $NO_X$ emissions are as much as three to six times lower than emissions from existing coal plants will be after Phase II of Title IV takes effect. Consequently, applying increasingly stringent emission standards and control technologies to new sources only produces small emission reductions relative to what could be achieved from existing sources.

Second, the incremental costs of controlling emissions from new sources (in $/ton) tend to be higher than from existing sources, primarily because the new sources have lower emission rates to begin with. For example, SCR controls on a typical existing coal unit would remove roughly 6,585 tons of $NO_X$ at a cost of roughly $870/ton. For a similar sized natural gas unit, operating at the same capacity factor, SCR controls would remove only 926 tons of $NO_X$ at a cost of roughly $1,575/ton.[14]

The incremental costs of reducing emissions from new sources will be higher for smaller units because of the economies of scale associated with the construction of the control technologies. For example, if the natural gas unit cited in the previous paragraph were 100 MW, as opposed to 400 MW, the SCR controls would reduce $NO_X$ emissions at a cost of roughly $2,170/ton. Similarly, if that same unit were to operate more like a peaking unit, with a 40 percent capacity factor, then the SCR cost would increase to roughly $3,372/ton. Consequently, the control technology requirements for new units can create a significant economic barrier to small generation units, including those designed for cogeneration (Casten 1998). This could limit the development of especially efficient generation technologies, as well as "distributed generation" technologies.

Third, owners of existing units have many more options and much greater flexibility for reducing emissions, compared with new sources' only option of installing LAER controls. Owners of existing units can choose from a variety of options, including combustion controls (e.g., LNB, Low $NO_X$ Coal-and-Air Nozzles), post-combustion controls (e.g., SNCR, SCR, gas reburn, SCONOX), operational controls (e.g., least-cost dispatch, reduced dispatch during ozone season), and even unit retirement. These owners have the flexibility to develop an emission reduction plan that identifies the least-cost strategy for achieving the desired level of emission reductions. In contrast, NSR requirements are essentially a command-and-control approach that requires owners of new sources to adopt the most expensive emission reduction option.

Fourth, existing sources are, and will continue to be, by far the largest contributor to $NO_X$ emissions from the electricity industry, while new sources will only represent a small contribution. This is partly due to the higher emission rates of existing sources, but also to the fact that existing sources are, and will continue to be, responsible for the vast majority of fossil-fired electricity generation. Consequently, the NSR provisions are directed toward a much smaller pool of potential emission reductions.

The disparity in emission standards created by NSR provisions is not only economically inefficient – it can also undermine the environmental objectives of the Clean Air Act. If this disparity creates a barrier to the development of new sources, then existing sources will continue to operate with lower efficiencies and much higher emission rates. Some power generation developers have argued that recent control technology requirements

[14] See Appendix A for assumptions used in this comparison. Both units are assumed to have a capacity of 400 MW and a capacity factor of 65 percent.

have created a "nearly insurmountable impediment" to the construction of new facilities, especially with regard to small units where the capital costs of control technologies cannot be justified (Casten 1998). If NSR requirements place too much pressure on new sources to achieve extremely low emission rates – regardless of cost or impact on the competitive market – then the introduction of new sources will be delayed and the associated emission reductions will be lost.

It should also be recognized that in those areas where a $NO_X$ cap-and-trade system is established, the additional control technologies required under NSR will provide no environmental benefits for the cap-and-trade region as a whole. The new source will have lower emissions, but the total amount of emissions produced will still be determined by the budget cap. The new source will simply purchase fewer allowances than it would have otherwise purchased, and some other source will use those allowances to support its emissions. The net result is that emissions will be reduced at the highest possible cost (i.e., that of LAER controls), and potential emission reductions from lower-cost sources (e.g., LNB, SNCR, repowering, unit retirement) will be forgone or postponed.

When existing sources make "major modifications" to their facilities, they are required by the Clean Air Act to meet the same NSR control technology standards as new units.[15] Consequently, existing sources choosing to take this route will no longer have this advantage over potential new sources of generation. Some owners of existing power plants have recently argued that this requirement inhibits them from making major modifications that would improve plant efficiency and reduce emissions of both regulated pollutants and unregulated pollutants (e.g., mercury and $CO_2$).

It is important to emphasize that we do not recommend that NSR requirements be reduced as a result of the disparity they create between existing and new facilities. On the contrary, the NSR requirements play an important role in ensuring that newer generations of power plants contribute as little as possible to the $NO_X$ and ozone problem. We do, however, recommend that environmental regulators consider options for obtaining some of the lower-cost emission reductions available from existing facilities. We also recommend that – unless and until these disparities are removed – economic regulators should account for the market distortions that they create when investigating the competitiveness of electricity markets. (See Section 8.)

## 3.3 New Source Review Emission Offset Requirements

Offsets required for new plants in nonattainment areas could create two kinds of market distortions. First, there is an inequity created by requiring the new entrant to pay the owner of existing sources for offsets. This inequity can create a barrier to entry for the developer of the new source, depending upon the cost and availability of offsets. Second, offsets may provide the owner of existing units with market power by providing them with a large share of a scarce commodity needed for market entry.

[15] The US Justice Department, on behalf of the EPA, recently filed lawsuits against seven Midwestern and Southern electric companies for making major modifications to existing plants without meeting the appropriate NSR standards.

In general, the presence and severity of market distortions associated with offsets will be a function of many factors, including:

- the stringency of the emission standards in the nonattainment area,
- the level of economic growth and resulting demand for offsets,
- the number of firms with emission sources in a given area,
- the distribution of these sources across different industries,
- the geographic sizes of both the nonattainment area and the market in which the firms compete (e.g., electricity),
- transmission constraints in the region, and
- any unique rules in the state or local regulatory framework (in addition to broadly applicable standards) that affect allowable emissions from different sources.

Stringent standards for existing sources make it more expensive and difficult for existing sources to create offsets. Similarly, strong economic growth resulting in strong demand for offsets would also create a shortage of offsets and drive prices up, leading to the same results. Absent the other factors listed above, these dynamics would not be a cause for concern about market distortions from offsets; high prices for offsets would incentivize incumbents to investigate more expensive options for reducing emissions and creating offsets. The offset requirement would be functioning as intended. However, the other factors listed above can pose constraints on offset markets, which will be exacerbated by the stringency of the emission standards and the amount of economic growth.

The presence of a very small number of firms with emission sources in a given nonattainment area may provide those firms with an excessive share of the offsets market. Large market shares may enable incumbents to interfere with the entry of competitors by either hoarding offsets or charging excessive prices for them. Note that in a nonattainment area with a small number of incumbent firms operating under very stringent standards, the supply of offsets may be so limited that market entry is restricted, even though no incumbents are hoarding offsets.

Owners of existing generating units often control large shares of the available $NO_X$ offsets, because power plants tend to offer the greatest potential for offset creation. As an indication of this potential, in nearly every OTC state power plants represent 90 percent or more of the state $NO_x$ allowance budget (OTC 1999). In other words, power plants in these states are responsible for the vast majority of stationary source $NO_X$ emissions that can participate in a $NO_X$ allowance system, or potentially generate $NO_X$ offsets. In addition, a small number of generation companies may own a large share of the power plants in a given area as a result of their historical monopoly position.

Another reason why owners of existing generating units often control large shares of the available $NO_X$ offsets is that it can be very difficult to create tradable offsets from some other sources of emissions. For example, there does not yet exist a feasible approach for creating tradable offsets from mobile sources. This can create a severe limitation on the $NO_X$ offset market in those areas where mobile sources are responsible for a significant portion of $NO_X$ emissions.

The distribution of incumbents across industries will also affect the potential for market power. Owners of existing generation units might have an incentive to prevent the entry of new generation units into the electricity market, whereas owners of $NO_X$ sources in other industries (e.g., dry cleaning) would not. Market power will be less of a concern in nonattainment areas where there are a large number of non-electric sources of $NO_X$ offsets. Unfortunately, as discussed above, electric generation units tend to dominate the potential market for $NO_X$ offsets.

The geographic size of an area is also correlated with the number of market participants. As the size of the area in which offsets can be created increases, the number of sources able to create offsets usually increases. In addition to the size of the nonattainment area, state rules governing offset trading are important factors in determining the size of the relevant market. In the case of nonattainment areas that are near each other or that span state borders, regulators often allow new or modified sources to use offsets from outside the local nonattainment area or state. However, sources using such credits must demonstrate that the emission reductions that generated the offsets will provide air quality benefits to the area in which the offsets are used.

In some states, offset trading rules lay out explicit “distance and directionality” constraints on interstate or inter-area trades. Usually these constraints require that offsets come from areas of equal or more severe nonattainment status, and they often place specific limitations on the distance the source of offsets can be from the user. (For example, new sources in the Beaumont/Port Arthur nonattainment area of Texas may use offsets from the Houston/Galveston area, but not from the entire Houston/Galveston area, only from sources within 200 km of the site of use.) Other states’ rules simply require sources using offsets from another area to demonstrate that the reductions generating the offsets will benefit the local nonattainment area. Guidelines for making such demonstrations are usually provided.

The Northeastern US provides a good example of the way that geographic constraints affect offset markets. This region is characterized by large nonattainment areas stretching across a number of relatively small states, and emissions from sources in one state can easily affect air quality on another state. In this situation, a shortage of offsets in one state could be a significant barrier to entry for new firms, while offsets may be available in upwind states. In light of this, regulators in many northeastern states have established formal Memoranda of Understanding (MOUs) allowing for offset trading across state borders. Table 3.2 shows the existing MOUs between northeastern states.

However, the Northeast now seems to be in transition to a more liberal geographic treatment of NSR offsets. Discussions have been ongoing at the OTC over the development of a single, regional MOU for offset trading. These discussions are primarily the product of two factors. First, the region is developing into a relatively complex patchwork of geographic trading rules which new sources must negotiate. Developers of new sources – and many regulators – are interested in simplifying this system. Second, many parties have argued that, in the creation of the OTC, it was determined that the area should be treated as a single region in terms of ozone pollution (and that this is why $NO_x$ budget allowances can be traded throughout the region). A proposed regional MOU is expected to be released by the OTC in the fall of 1999, however, there are still controversial issues around the idea of a regional MOU, and it is not clear whether one will ultimately be adopted.

**Table 3.2 MOUs Governing Interstate Offset Trading.**

| State | Offset MOUs |
|---|---|
| Connecticut | MOUs with New York and New Jersey. |
| Delaware | None. |
| Maine | MOU with Massachusetts |
| Maryland | None, but offsets from outside the state are considered on a case by case basis. |
| Massachusetts | MOU with Maine. |
| New Hampshire | None. |
| New Jersey | None, but offsets have been accepted from Pennsylvania. |
| New York | MOUs with Connecticut and Pennsylvania |
| Pennsylvania | MOU with New York. |
| Rhode Island | None, but an MOU with Connecticut is under discussion. |
| Vermont | None, but offsets from outside the state would be considered on a case-by-case basis. |

## 3.4 Emission Cap-and-Trade Programs

### Potential Problems Arising From Allowance Allocations in General

Cap-and-trade programs to reduce air emissions do not necessarily create distortions between existing and new sources. However, problems can arise from the methodology that is chosen for allocating allowances among the various market participants. If allowances are allocated in a way that is inequitable, or that enables one or more market participants to amass a large share of available allowances, then there are likely to be distortions in the electricity market.

Current $SO_2$ and $NO_X$ allowance allocation schemes create two potential problems in the electricity market. First, they tend to allocate allowances inconsistently between existing and new units, resulting in significant inequities. The $SO_2$ program does not allocate any allowances to new sources. The $NO_X$ allowance allocation schemes developed to date either provide new sources with no allowances, or provide new sources with fewer allowances than is provided to comparable existing units.

New sources tend to receive fewer $NO_X$ allowances than is fair because the allowances are allocated to existing units on the basis of their heat input (i.e., MMBtu) in a historical, baseline year. This input-based allocation approach rewards owners of generation plants for operating with higher levels of heat input, thereby rewarding inefficiency in the baseline year. Under this input-based approach, new sources receive significantly less allowances than a comparable existing source, because new sources tend to operate at substantially higher levels of efficiency. In addition, there may be a significant difference between historical levels of operation and actual levels of operation in a given year. Owners of existing units can obtain windfall allowances from plant upgrades, repowerings or retirements, while new sources do not have this option.

The inconsistent allocation of $SO_2$ and $NO_X$ allowances between existing and new sources is particularly perverse when compared to a situation where the cap-and-trade program does not exist. Assume, for example, that all sources were required to meet a $NO_X$ standard of 0.15 lb/MMBtu without a cap-and-trade program (i.e., a command-and-control approach). Both existing and new sources would be required to incur the full cost of reducing their $NO_X$ emissions down to this emission rate. If a cap-and-trade program is introduced, and all allowances are allocated to existing sources by multiplying heat input by the 0.15 lb/MMBtu rate, then these sources will essentially have to pay for the cost of bringing their emissions down to this standard, but not lower. New sources however, would be required to pay for every ton of $NO_X$ emissions. This means that they would essentially be required to pay the cost of bringing their emissions down to zero. This is clearly not an equitable outcome.

The second problem with allocating the majority of allowances to incumbent utilities is that it increases the likelihood that allowances will be concentrated among a relatively small number of players, thereby increasing the opportunities for withholding allowances or otherwise manipulating the allowance trading system. Some incumbent electric utilities may have significant amounts of market power during the transition to competitive electricity markets, and providing them with pollution allowances based on their historical market share could serve to increase the potential for market power abuse.

In some ways, allowance and offset markets may have fewer constraints than energy and capacity markets, and as a result, less potential for market power accumulation. For example, emission trading systems are not constrained by electricity transmission. Companies seeking $SO_2$ allowances can purchase them from any company located in the US. From this perspective, it is less likely that market power will be wielded in the $SO_2$ allowance market than in regional electricity markets.

However, if an allowance market is constrained to a relatively small geographic region, there is far greater potential for market power accumulation. For example, if a particular state decides to not participate in interstate $NO_X$ trading system, then the in-state allowance market may be limited to a small number of players dominated by the owners of existing in-state generation units. As another example, the $NO_X$ offset market in southern California is geographically constrained because there are no upwind sources with which to trade offsets, as a consequence of the prevailing easterly winds.

### Potential Problems Arising From the EPA's Proposed $NO_X$ Trading Policies

As discussed in Section 2.3, the EPA proposed a model rule for a $NO_X$ Budget Trading Program in its recent SIP Rule. In the model rule, EPA provides states with some flexibility in developing their $NO_X$ Budget Trading rules. However, if states deviate significantly from EPA's model they will not be allowed to participate in interstate trades.

The EPA's model rule contains a set-aside for allowances to new sources. This set-aside is an important step towards eliminating the inequity created by allocating all allowances to existing sources. However, if this set-aside is not large enough to cover all new sources that seek to enter the market, then some inequity will remain.

There are two reasons why the EPA's proposed new source set-aside (five percent for 2003-2006, and two percent in following control periods) might not be sufficient to address all new sources. First, the methodology used to determine the set-aside might understate the development of new sources. The EPA used projections of annual growth in capacity utilization (0.5 percent per year) to estimate the need for new sources in the electricity market in coming years (EPA 10/1998).[16] However, this growth in capacity utilization is significantly less than the growth rate of electricity demand (1.8 percent per year, from 2001 to 2010) assumed by the EPA (EPA 3/1998).

Therefore, new sources are assumed to be introduced at a rate much lower than the rate of growth of electricity demand. This implies that new sources will not be replacing existing generation sources, and that existing generation sources will be increasing their levels of electricity generation. To the extent that this assumption is inaccurate, the EPA's five percent and two percent set-asides will not provide sufficient allowances to cover new sources.

Second, EPA's proposed set-aside may not be sufficient to address the variation in new source development in different states, as indicated in Table 3.3. This table presents the proposed $NO_X$ allocations for each state affected by the SIP Rule, the capacity of new merchant plants that have recently been announced in each state, and the percent of the total allocations that would be required by the new sources under typical operating conditions.

Table 3.3 presents estimates of the total allocations required of new units using two different methods. The second column from the right indicates the amount of allowances that would be required by new sources if allowances were allocated on the basis of 0.15 lb/MMBtu times their heat input (as proposed by the EPA). The rightmost column indicates the allowances required by new sources if allowances were allocated on the basis of their permitted emission rate times their heat input (as has been proposed by some states).

If allowances are allocated as proposed by the EPA, there may be as many as eleven states where a five percent set-aside for 2003 would fall short of the demand for offsets. Even if allowances are allocated on the basis of the new source's permitted rate (which would create an inequity between existing and new sources) there would still be three states where a five percent set-aside would be insufficient.[17]

16 The five-percent set-aside for the 2003 to 2006 period needs to account for all new sources installed after May 1995, and the two percent set-aside after 2006 needs to account for new sources installed after 2003.

17 These numbers are presented for illustrative purposes only – actual results may vary. Some of the new merchant capacity might be delayed or cancelled. If new sources operate at lower capacity factors, they would require fewer allowances. Higher capacity factors would require more allowances.

**Table 3.3 New Power Plants Announced in SIP States, and Need for Set-Asides**

| State | State $NO_X$ Allownaces (tons) | New Generation Capacity (MW) | Percent of State Allowances Required (using 0.15 rate) | Percent of State Allowances Required (using permitted rate) |
|---|---|---|---|---|
| AL | 27,440 | 100 | 0% | 0% |
| CT | 2,418 | 3,606 | 180% | 24% |
| GA | 28,563 | 3,800 | 16% | 2% |
| IL | 29,776 | 4,820 | 20% | 3% |
| IN | 45,200 | 4,270 | 11% | 2% |
| KY | 36,014 | 824 | 3% | 0% |
| MA | 13,907 | 11,243 | 97% | 13% |
| MI | 25,027 | 1,630 | 8% | 1% |
| MS | 22,117 | 750 | 4% | 1% |
| NJ | 9,104 | 1,900 | 25% | 3% |
| NY | 28,979 | 4,783 | 20% | 3% |
| NC | 28,468 | 800 | 3% | 0% |
| OH | 44,101 | 2,340 | 6% | 1% |
| PA | 46,223 | 3,916 | 10% | 1% |
| RI | 1,059 | 765 | 87% | 12% |
| TN | 24,117 | 460 | 2% | 0% |
| VA | 17,109 | 300 | 2% | 0% |
| WV | 25,117 | 1,116 | 5% | 1% |
| WI | 16,041 | 654 | 5% | 1% |

*State $NO_X$ allowances are from EPA 12/1997. Information was unavailable for some states. EPA cautions that these are preliminary, proposed allowance allocations, and the actual allocations may vary considerably. They are presented here for illustrative purposes. New capacity estimates are from ESPA 1999, and include operational units, units that are expected to be installed by 2002, and units expected to be installed shortly thereafter. For simplicity, we assume that all new plants will have a heat rate of 6,773 Btu/kWh, a permitted $NO_X$ emission rate of 0.02 lb/MMBtu, and a capacity factor of 65 percent.*

## Potential Problems Arising From State $NO_X$ Trading Policies

Based on our review of some states that have developed new source set-aside policies to date, a significant number of them deviate from the EPA model rule in ways that are not favorable to new sources. To the extent that state policies do not provide sufficient set-asides for all new sources, they will compromise the EPA's objective of treating new and existing sources consistently, and they will create inequities between competitors.

Table 3.4 presents a summary of state policies for new source set-asides under the OTC $NO_X$ Budget Program, and Table 3.5 presents a summary of state polices for new source set-asides under the EPA's SIP Rule. As indicated in the tables, some states have smaller new source set-asides, while others do not have set-asides at all. Some states determine the number of allowances to be set aside on the basis of permitted emission rates, as opposed to a rate of 0.15 lb/MMBtu. Some states require new sources to pay a fee for set-aside allowances, with the revenues from the fee being returned to the owners of existing sources. This practice largely defeats the purpose of the new source set-asides.

As described in the previous section, there is likely to be significant variation across states in the demand for new sources. While the EPA has acknowledges that there may need to be different set-asides in different states, states appear to be hesitant to set aside more allowances than recommended by EPA. Very few states have proposed larger set-asides, while a number of states have proposed smaller ones.

**Table 3.4 New Source Set-Aside Policies Under the OTC $NO_X$ Budget Program**

| State | New Source Set Aside Policy |
|---|---|
| Connecticut | 5% of the allowance budget (224 allowances in 1999) is set aside for new sources. |
| Delaware | No allowances are set aside. |
| Maine | Maine does not have a NOx Budget rule in place yet. |
| Maryland | 6.25% of the allowance budget is set aside for new sources (2% of this is for unknown new sources, 3% for Clean Air Projects). |
| Massachusetts | 2.75% of the 1999-2003 allowance budget (500 allowances in 1999) is set aside for new sources. |
| New Hampshire | 8.5% of the allowance budget (445 allowances in 1999) is set aside for new sources. |
| New Jersey | Each new source constructed between 1999 and 2003 receives allowances for the amount of NOx it can potentially emit during the ozone season, and each source receives the actual amount emitted during the non-ozone season. After 2003, new sources will be allocated allowances from a pool of 820 allowances. |
| New York | 5% of the allowance budget is set aside for new sources. |
| Pennsylvania | No allowances are set aside |
| Rhode Island | No allowances are set aside. |
| Vermont | No allowances are set aside. |

*Source: State Environmental Agencies*

**Table 3.5 New Source Set-Aside Policies Under the $NO_X$ SIP Rule**

| State/Agency | New Source Set Aside Policy |
|---|---|
| US EPA | 5% of allowances set aside (2003-2005), 2% set aside thereafter. Available on a first-come, first-served basis. Available at no cost. Allowances are reallocated every year. |
| Georgia | New sources are charged a fee for the set-asides. Revenues from the fee are provided to the incumbent utilities. |
| Illinois | New sources are charged a fee, which will be based on an index of market price in the previous ozone season. Revenues from the fee are provided to the incumbent utilities. |
| Indiana | Same as the EPA model rule. |
| Kentucky | No set-asides are available for new sources. |
| Ohio | $NO_X$ trading program has not been established yet. |
| Pennsylvania | Same as the EPA model rule, except that new sources are allocated allowances on the basis of permitted heat rate times heat input. |
| Rhode Island | All excess allowances will be set aside for new sources. |
| Tennessee | 4% of allowances set aside (2003-2005), no set-asides are available thereafter. |

*Source: State Environmental Agencies*

## 3.5 Quantitative Assessment of Market Distortions

### Emission Offset Requirements

Emission offsets are fundamentally different from emission allowances because they represent one ton per year of emissions in perpetuity, whereas allowances represent only one ton in a single year. Consequently, one would expect offsets to cost considerably more than allowances. To date this has not been the case. As indicted in Table 2.3, the recent prices for $NO_X$ offsets are in the range of $2,000 to $6,000 per ton per year, depending upon the region and the degree of nonattainment in the relevant region. Presumably, these prices are relatively low because many of the offsets to date have been generated from plant shutdowns, which have created an inexpensive bank of offsets. If so, then the price of offsets can be expected to increase in the future.

The impact of offsets on electricity costs (in terms of $/MWh) is currently quite small. A typical new gas combined-cycle unit subject to NSR would emit roughly 163 tons per year. Assuming that offsets cost $6,000/ton/year, this would translate into roughly $0.04/MWh.[18] The $/MWh cost is low because the one-time, up-front cost of the offsets is annualized using a 10 percent capital recovery factor.[19] In addition, the amount of $NO_X$ emissions from these unit is low, because (a) natural gas combined-cycle units have low emissions to begin with and (b) NSR requires that they have low-$NO_X$ combustion technology and SCR controls.

However, $NO_X$ offsets pose a financial burden on new power plant developers, because of the need to pay the up-front $NO_X$ offset costs at the time of power plant construction. In the example cited above, the developer of the typical new gas unit would have to raise an additional $978,000 to purchase the $NO_X$ offsets.

The inequity associated with emission offset requirements is compounded by the fact that the owners of existing units receive revenues for the offsets, thereby providing an additional advantage over their competitors. In some cases, these revenues may be counterbalanced by costs incurred in creating the offset, but in others (e.g., the retirement of a unit) the owner may incur few costs, and the revenue generated by the offset sale would contribute to the inequity.

Note that this analysis is only applicable to nonattainment areas in which offset markets are functioning reasonably well. In at least one area of the country, San Diego County, the supply of offsets is so limited that potential entrants cannot acquire sufficient offsets at any price. (See Section 6.2.) In this case, the offset requirement is not resulting in a quantifiable, incremental cost to the new entrant; the requirement is preventing market entry. The cost increment to electricity consumers in the region is equal to the above-market capacity payments that the existing generators in San Diego County receive. This cost can be expected to grow until the barrier to entry is removed, and competitors enter the market.

## Allowance Allocations

The free allocation of $SO_2$ allowances to owners of existing generators provides a direct reduction in environmental compliance costs – a reduction that is not available to new sources. During Phase I of the $SO_2$ allowance program, $SO_2$ allowances represent a

[18] Here we assume a 400 MW gas plant, with a 65 percent capacity factor, a heat rate of 6,773 Btu/kWh, an emission rate of 0.02 lb/MMBtu, and a capital recovery factor of 10 percent. See Appendix A.

[19] Some power plant owners might use different capital recovery periods and different discount rates, resulting in different annualized costs.

compliance cost reduction to owners of existing units of roughly \$1.3/MWh.[20] During Phase II of the $SO_2$ program, fewer allowances will be allocated, but they can be expected to be worth more. These allowances represent a compliance cost reduction of roughly \$1.2/MWh.[21]

Similarly, the free allocation of $NO_X$ allowances to owners of existing generators provides a direct reduction in compliance costs that is not generally available to new sources. Assuming that the $NO_X$ SIP Rule is implemented (or something similar to it), these allowances might be worth roughly \$2.3/MWh for a typical existing facility.[22] To the extent that new sources are provided free allowances through new source set-asides, their compliance costs will be reduced.

The sum of the reduction in compliance costs from allocation of both $SO_2$ and $NO_X$ allowances would be roughly \$3.5/MWh. This is approximately ten percent of the cost of generating electricity and therefore could be an important factor in the operating economics of some units.

### Emission Standards and Control Technology Requirements

It is difficult to quantify the magnitude of the additional costs imposed upon new sources by NSR control technology requirements. Different requirements apply to different plant types, and there are many options available to power plant owners to meet the requirements. Units in nonattainment areas are subject to different regulations than units in attainment areas. To make the comparison more difficult, the RACT and LAER standards differ somewhat from state to state.

Nevertheless, a simple comparison is useful for illustrative purposes. In nonattainment areas, existing sources are required to install RACT controls. In many cases this requirement can be met with low-$NO_X$ burners or other types of combustion controls, at a cost of roughly \$0.5/MWh.[23] New sources are required to install LAER controls. In most cases, this standard requires the installation of low-$NO_X$ combustion and SCR controls, at a cost of nearly \$1.0/MWh – roughly twice that required of existing sources.[24]

However, this comparison does not capture the full amount of compliance costs incurred by new sources. New generating facilities are explicitly designed to be more efficient and to produce less emissions than conventional facilities. Consequently, a portion of the compliance cost of a new power plant will be embedded in its construction costs. Also, a power plant developer might choose a natural gas facility over a coal facility, in part to produce lower emissions. As a result, a portion of the compliance costs of the new gas

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[20] Here we assume a coal plant heat rate of 10,325 Btu/kWh, $SO_2$ allowances are allocated on the basis of 2.5 lb/MMBtu times the heat rate, and are priced at \$100/ton.

[21] Assuming a coal plant heat rate of 10,325 Btu/kWh, $SO_2$ allowances are allocated on the basis of 1.2 lb/MMBtu, and are priced at \$200/ton.

[22] Assuming a coal plant heat rate of 10,325 Btu/kWh, $NO_X$ allowances are allocated on the basis of 0.15 lb/MMBtu, and are priced at \$3,000/ton (EPA 9/1998a).

[23] Assuming a 400 MW existing dry-bottom, wall-fired coal unit, operating at 65 percent capacity factor. See Appendix A for details of the costs of control technologies.

[24] Assuming a 400 MW new gas combined cycle unit, operating at 65 percent capacity factor.

facility will be embedded in its higher fuel costs.  These can be considered "indirect" compliance costs, as opposed to the "direct" compliance costs represented by the cost of purchasing allowances or installing control technologies.

When comparing the compliance costs of new versus existing power plants, it is important to recognize both direct and indirect compliance costs.  Unfortunately, it is very difficult, if not impossible, to identify precisely the indirect compliance costs.  There are many reasons why an existing coal unit would have different construction and operating costs than a new unit, and all of the differences in cost cannot be ascribed to compliance with environmental regulations.

As a result of incurring higher direct and indirect compliance costs, the new source will produce significantly lower emissions than existing units.  The existing coal plant described above will produce roughly 4,390 tons of $NO_X$ per year, while the new gas unit will produce only 163 tons of $NO_X$ – for the same amount of electricity generated.  The ability of existing sources to emit so much more pollution is another indication of the inequity created by the different emission standards.

# 4. Market Distortions in the Context of Power Plant Divestiture

## 4.1 Overview

When an electric utility divests its power plants, the emission allowances and offsets tend to be shifted to the new owners of those plants. In some circumstances, there is a risk that the new power plant owners will control a large share of the emission allowances or offsets in the regional market. Control of a large market share of emission allowances can create horizontal market power in the allowance market. In addition, control of a large market share of emission allowances can create vertical market power between the allowance market and the electricity market.

In some recent power plant divestiture cases, regulators have taken steps to increase the number of buyers, thereby reducing the potential for new owners to obtain large shares of the generation market. For example, the New York Public Service Commission recently required Consolidated Edison to sell its power plants in three separate bundles to three separate companies in order to mitigate market power concerns. This practice will also tend to mitigate concerns about market power associated emission allowances and offsets.

However, not all power plant divestitures are constrained in this way. In addition, there may be circumstances in which a single generation company purchases power plants through a number of different divestitures in one region. While one of these divestitures, taken in isolation, may not create market power, problems may arise from a buyer's accumulation of plants from a number of separate divestitures.

In all divestiture cases, regulators should investigate the potential market power issues that might as a consequence of environmental regulations – in addition to those that arise in the energy and capacity markets. The greatest potential for environmental market power problems arising from divestiture will exist in those cases where the new owner's plants are located within a nonattainment region with a cap-and-trade system. Other factors that would influence the potential market distortion from divestiture include the extent of fossil-fired capacity owned by the purchasing company, the purchasing company's market share of generation in the region, transmission constraints in the region, and the costs of allowances or offsets in the region.

## 4.2 Case Study of the Commonwealth Edison Divestiture

### Background on the Divestiture

On March 23, 1999, Commonwealth Edison Company (ComEd) announced that it had agreed to sell its fossil-fired generation plants to Edison Mission Energy (Mission). The package included six coal-fired units (5,645 MW), one oil/gas plant (2,968 MW) and a number of peaking units (1,429 MW), with a combined capacity of 10,042 MW (ComEd

1999). This represents the largest amount of fossil-fired capacity sold to a single purchaser in the US to date.

Mission is a subsidiary of Edison International, which is the parent company of Southern California Edison Company. Mission is very active in developing power plants, with projects in Australia, Indonesia, Italy, the Philippines, Spain, Thailand, Turkey, the United Kingdom, and the United States. Mission does not currently own any power plants in the Illinois region, although it has proposed building 500 MW of gas-fired generation in the city of Chicago. Mission has pledged to invest more than $200 million in environmental enhancements, many of which will be for $NO_X$ controls (ComEd 1999).

### Relevant Air Quality Regulations in Illinois

Illinois is one of the 22 states that are included in the EPA's SIP Rule. Any $NO_X$ allowances that are allocated to the Mission plants under the SIP Rule will presumably be owned by Mission. If the SIP Rule is abandoned because of the current court challenges, all the power plants purchased by Mission will be subject to Section 126 Petitions (EPA 12/1998). Similarly, all of the $SO_2$ allowances associated with these power plants will be owned by Mission.

The Illinois Environmental Protection Agency (IL EPA) recently conducted a public process to establish a $NO_X$ allowance allocation rule, designed to assist the state in complying with the EPA's SIP Rule. The IL EPA developed a draft rule, but before the rule could be finalized the EPA SIP Rule was called into question by the court challenge. The final draft of the Illinois $NO_X$ allocation rule has been delayed until there is some resolution of the EPA SIP Rule.

The draft Illinois $NO_X$ allowance allocation rule contains provisions to allocate allowances to new sources. These new source set-aside provisions are similar to those proposed by the US EPA, with a five percent set-aside for the 2003, 2004 and 2005 control seasons, and a two percent set-aside thereafter. However, the draft Illinois rule contains the following important differences from the US EPA proposal (IL EPA 1999).

- Some new sources would be required to pay a charge for the $NO_X$ allowances, and most of the revenues generated by the charge would be provided to the owners of existing power plants. The IL EPA has not determined the details of how this charge would work, but the goal would be to set a charge based on the market price of $NO_X$ allowances in the previous ozone season. The charge would be applied to only those new sources that commence operation after 2002, so new sources that commence operation from 1995 through 2002 would be exempt from the charge.

- All new sources (plants on-line after 1995) will receive allocations on the basis of their heat input times the more stringent of 0.15 lb/MMBtu or their permitted emission rate. This means that new sources will receive fewer allowances than existing facilities, even after normalizing for heat input. Perversely, the new plants that pay for additional control technologies will receive fewer allowances as a result of their lower permitted emission rates.

- Baseline allocations will be fixed for the first three years of the program: 2003, 2004 and 2005. The allocations for 2006 and beyond will not be based on heat input of all power plants in operation as of 2003, as proposed by the US EPA. Instead, owners of existing plants (those that were operating before the end of 1995) will be guaranteed 80 percent of their baseline emissions. Owners of plants put on-line after 1995 will receive their heat input times the more stringent of 0.15 lb/MMBtu or their permitted emission rate. If the allowances remaining after the existing plants receive their 80 percent is not enough to cover the needs of all new sources, those allowances will be pro-rated across the new sources.
- The allowances are allocated to new sources on a pro-rata basis, as opposed to a first-come first-served basis.

The Chicago area is currently classified as being in severe nonattainment of the NAAQS for ozone. This means that any new power plants wishing to locate in this area would normally be subject to NSR and would be required to purchase $NO_X$ offsets for every ton of $NO_X$ emissions.

However, the Chicago area has been given a "$NO_X$ waiver" under Section 182(f) of the Clean Air Act (IL EPA 1999). Section 182(f) allows a state to waive NSR requirements if it can demonstrate that additional $NO_X$ emissions will not act as ozone precursors. This can occur when the existing balance of $NO_X$ and VOC emissions in a region is such that VOC emissions are primarily responsible for the production of ozone, and additional $NO_X$ emissions would not increase ozone levels. In such areas, VOC emission reductions represent the primary option for reducing ozone levels.

A $NO_X$ waiver means that new sources are not subject to NSR requirements for $NO_X$ and therefore do not have to purchase $NO_X$ offsets. A $NO_X$ waiver also means that existing sources do not have to meet the Title I requirements to install RACT controls.

This $NO_X$ waiver has important implications for power plant development in the Chicago area. There are currently roughly 20 applications for new power plants in Illinois, and roughly one-half of those are planning to locate in the Chicago area.[25] The Illinois EPA notes that there may have to be $NO_X$ reductions achieved in the Chicago area over time, but that these will probably be achieved as part of a more general, state-wide approach, as opposed to a focused, local NSR effort (IL EPA 1999).

The $NO_X$ waiver has been granted on the basis of computer modeling of emissions in the Chicago area, using the EPA's current one-hour ambient air quality standard for ozone. If the EPA is successful in upgrading the standard to the eight-hour version, then there will be many more areas in Illinois that are in nonattainment for ozone. It is difficult to anticipate at this time whether these additional nonattainment areas would receive a $NO_X$ waiver. The balance of $NO_X$ and VOC emissions that allow for a $NO_X$ waiver can vary significantly from one region to another. However, it is unlikely that the Chicago area $NO_X$ waiver would be affected by the eight-hour standard, because the balance of $NO_X$

[25] All of these applications are for natural gas facilities. Roughly one-third is for baseload units, while two-thirds are for peaking units.

and VOC emissions would remain unchanged, i.e., it would still be assumed that $NO_X$ is not a precursor to ozone in that area (IL EPA 1999).

There is no time limit on the $NO_X$ waiver that applies to the Chicago area. However, if the VOC emissions in the area are significantly reduced over time, then one could petition the EPA to reconsider whether the $NO_X$ waiver is still appropriate. Implementation of the $NO_X$ SIP Rule (or provisions of the Section 126 Petition) would not affect the $NO_X$ waiver – power plants would be required to meet the provisions of those standards, but would still be exempt from NSR requirements.

### Market Distortions Arising From Allowance Allocations in Illinois

The existing $SO_2$ allowance allocation scheme will create a market distortion, due to the inequitable treatment of new versus existing power plants. Existing sources will be allocated $SO_2$ allowances for all emissions below 1.2 lb/MMBtu free of charge, while new sources will be required to purchase all the $SO_2$ allowances they need. The EPA has allocated 193,361 tons of $SO_2$ allowances to the Mission fossil-fired power plants for each year from 2000 through 2009 (EPA 9/1998b). This means that Mission will enjoy environmental compliance cost savings of roughly $38.7 million per year, or approximately $1.3/MWh.[26]

The draft $NO_X$ allocation rule will also create a market distortion, if it is implemented as currently proposed. The draft rule allows existing sources to be allocated $NO_X$ allowances for all emissions below 0.15 lb/MMBtu free of charge, while new sources will be required to purchase some, or all, of the $NO_X$ allowances they need. New sources installed after 2003 will have to pay a charge for all of their $NO_X$ allowances. For these sources, the inequity between new and existing power plants is especially great, because the revenues generated by the new sources will be provided to the existing sources. New sources installed from 1996 through 2002 will only receive a pro-rata share of the free new source set-aside allowances. To the extent that there are not enough set-aside allowances to go around, these new sources will have to purchase them from the open market.

It is likely that there will not be enough new source set-asides to meet the demand from developers of new plants in Illinois. Currently, the IL EPA has construction permit applications and permitted sources for new generation totaling of 9,362 MW, for just the three years of 1999, 2000 and 2001. Under typical operating assumptions, these plants could require as many as 1,504 tons of allowances, which would represent roughly 5.1 percent of the total $NO_X$ allowances for the state of Illinois.[27] The IL EPA has proposed to set aside only five percent of allowances to cover all new sources installed from May 1995 through 2005.

[26] Here we assume $SO_2$ allowance costs of $200/ton, and annual generation from the Mission power plants of 30,000 GWh. In 1998, generation from these plants was 29,906 GWh.

[27] Here we assume a new natural gas combined-cycle facility with a $NO_X$ emission rate of 0.02 lb/MMBtu, heat rate of 6,773 Btu/kWh, and capacity factor of 65 percent. The US EPA's initial estimate of $NO_X$ allowance allocations to all sources in the state of Illinois is 29,776 tons.

This analysis actually understates the shortage of set-asides that new sources will face. The US EPA has recommended that new sources should be allocated allowances on the basis of heat input times an emission rate of 0.15 lb/MMBtu, rather than on the basis of the permitted emission rate. This approach was recommended in order to treat new sources consistently with existing facilities, and to avoid penalizing those new sources that have controlled emissions to especially low levels (EPA 10/1998). If the new sources planned for Illinois for 1999, 2000 and 2001 were allocated allowances according to the US EPA's proposed methodology, they would require as many as 11,257 tons of allowances, which would represent roughly 38 percent of the total $NO_X$ allowances for the state of Illinois.

In 2006 and beyond, even fewer $NO_X$ allowances will be set aside for new sources because of the provision guaranteeing existing facilities 80 percent of their baseline emissions. As load grows, capacity factors increase, and sources installed after 1995 begin to be treated as existing sources, there will be a greater demand for allocations. In order for the older power plants to receive 80 percent of their baseline emissions, the number of allowances allocated to new sources will have to be reduced.

### Market Distortions Arising From PSD and NSR Requirements in Illinois

In those areas that are in attainment of the ozone standard, new sources are required to meet PSD standards, which require installation of BACT $NO_X$ controls. Existing coal units are required to meet the federal Title IV Phase I and Phase II $NO_X$ standards, but this generally requires the much less stringent RACT controls.

In those areas that are in nonattainment for ozone, new sources would normally be required to meet NSR standards, which require the installation of LAER controls and the purchase of $NO_X$ offsets. However, in the case of the Chicago nonattainment area, the $NO_X$ waiver eliminates the NSR requirement. Instead, all power plants will have to meet PSD requirements, in the same way that they do in attainment areas. Therefore, the inequity between new and existing sources described in the previous paragraph will apply in nonattainment areas as well.

The baseload units currently applying for permits in Illinois all have SCR control technologies, while the peaking units do not. All units currently applying for permits in Illinois have low-$NO_X$ combustion controls (IL EPA 1999). The Title IV Phase II standards essentially require existing coal units to install low-$NO_X$ combustion controls. Therefore, the primary implication of the different PSD and NSR standards between new and existing sources in Illinois is that new baseload units have to install SCR controls, while existing coal units do not.

If the $NO_X$ waiver is lifted from the Chicago nonattainment area, then new sources will be subject to LAER standards and will have to purchase $NO_X$ offsets. Mission is likely to have considerable influence on the availability and price of $NO_X$ offsets, because it owns 5,447 MW of fossil capacity currently located in nonattainment areas.[28] However, it is difficult to predict what the price and availability of offsets would be, given that there has

[28] Roughly 2,749 MW of Mission's capacity in nonattainment areas remains uncontrolled for $NO_X$, while the remaining 2,698 MW of capacity has only $NO_X$ combustion controls (EPA 1997).

been no experience with an offset market in that region yet. It is also difficult to predict whether and when the $NO_X$ waiver might be lifted.

If the EPA eventually applies a more stringent eight-hour ambient air quality standard for ozone, then there will be many more ozone nonattainment areas in Illinois. In those nonattainment areas where Mission owns a large share of the fossil-fired power plants, it might have a significant influence on the availability and price of $NO_X$ offsets. Again, it is difficult to predict what in offset market might look like in these regions, given that there are so many unknowns still to be resolved, and there is no experience with offset markets there.

### Market Distortions in the Context of the Commonwealth Edison Divestiture

With regard to the markets for $SO_2$ and $NO_X$ allowances, the ComEd divestiture itself is unlikely to create market distortions. This is primarily due to the size of the $SO_2$ and $NO_X$ allowance markets, and the fungibility of the allowances. According to the US EPA's initial estimates of $NO_X$ allocations under a Model Trading Rule, the Mission plants would be allocated roughly 12,876 $NO_X$ allowances per year (EPA 12/1998). This would equal roughly three percent of all the allowances allocated to all of the states affected by the SIP Rule, and is therefore unlikely to represent an excessive market share.

If there is a limit imposed upon the regions within which $NO_X$ allocations can be traded, then Mission could end up with an excessive share of this market. For example, if $NO_X$ trading were limited to the state of Illinois, then Mission's $NO_X$ allocations would represent roughly 43 percent of the trading market, which would raise concerns about market power in the $NO_X$ allowance market.

With regard to the $NO_X$ offset market, the ComEd divestiture might have created market power problems, by placing the potential to generate many $NO_X$ offsets in the control of a single entity. Depending upon the ability of other industries in the Chicago area, Mission might have been able to influence the availability of offsets for competing new power plant developers. However, the $NO_X$ waiver for the Chicago area eliminates this market power concern for the moment. If the $NO_X$ waiver is lifted, or if the EPA is successful in implementing the eight-hour ambient air quality standard for ozone, then there might be market power concerns in the offset markets that Mission participates in.

Even though the ComEd divestiture is unlikely to *create* market distortions in the allowance and offset markets, it is important to recognize that there may be distortions present in those markets that can contribute to market power. Economic inequities due to inconsistent environmental regulations can be a barrier to entry – either by themselves, or when combined with other factors that can hinder the development of new sources.

In sum, inconsistent environmental regulations result in the following inequities in Mission's electricity markets:

- New sources in Illinois are required to purchase all of their $SO_2$ allowances, while Mission is allocated free allowances up to the 1.2 lb/MMBtu level.
- New sources in Illinois are likely to be allocated less $NO_X$ allowances than Mission, because existing sources are guaranteed 80-100 percent of their baseline

emissions while new sources are provided with only a pro-rata share of the available new source set-asides, and because the five percent set-aside might not be sufficient to cover all the new sources in the state.

- New sources installed after 2003 are required to pay a charge for $NO_X$ allowances, while Mission will be able to obtain revenues generated from this charge.
- New sources in Illinois are required to install BACT controls (under PSD), while FirstEnergy is required to install only RACT controls on its coal units.

A thorough market power analysis must consider these barriers to entry in order to fully assess the competitiveness of the markets being analyzed. The Illinois Commerce Commission did not investigate the market power issues associated with the ComEd divestiture. However, Professor William Baumol, testifying on behalf of ComEd, argued that the divestiture should not create market power problems (Baumol 1999). Importantly, Professor Baumol's analysis assumes that there are no barriers to entry to the electricity markets in the region. To the extent that inconsistent environmental regulations create barriers to entry, not to mention other factors that will create barriers to entry, this assumption will not be true, and Professor Baumol's conclusions will not be valid.

# 5. Market Distortions in the Context of Mergers and Acquisitions

## 5.1 Overview of Market Power Issues Raised by Mergers

The merger of two or more electric companies can provide the new company with an excessive share of the electricity market, which can lead to market power problems. In reviewing a merger proposal FERC has the responsibility to conduct a market power analysis, and to impose conditions or reject the merger if it finds that the new company will possess market power. In its market power analyses, FERC reviews a number of different markets associated with electricity services, including capacity markets, short-term energy markets, long-term energy markets, spinning reserve markets and markets for other ancillary services (FERC 1996).

The market for emission allowances should also be analyzed in the context of electric utility mergers and acquisitions. The combination of two large companies can result in an accumulation of an excessively large share of the total market for allowances or offsets. A large market share in the allowance or offset markets can cause many of the same market power problems that exist in the markets for other electricity products.

FERC has recognized that environmental regulations can create market power problems in the context of electric utility mergers. In its May 14, 1997 Order in the Primergy merger case, FERC decided not to approve the proposed merger in part because it found that differential environmental regulations presented a barrier to entry:

> We find that the record establishes that such factors as the lengthy regulatory approval a new entrant must undergo and the length of time between planning and completion of new generation would in all likelihood prevent new entrants from mitigating Primergy's market power in a timely fashion and would prevent the expansion of existing capacity in a timely fashion. *In addition, there are also significant environmental obstacles that would frustrate new entrants, such as the requirement that new entrants emit less sulfur dioxide than Primergy's existing facilities and the related need to purchase sulfur dioxide emission allowances*....
>
> In the face of this evidence, we must reverse the Initial Decision's finding that the proposed merger would not have anti-competitive effects. Not only has it been demonstrated that the proposed merger would create highly concentrated markets and thereby create or enhance Primergy's market power or facilitate its exercise, but Certain Intervenors also have demonstrated that due to such factors as regulatory delay and the costs associated with environmental compliance, as well as a limited number of new entrants within the relevant time frame, timely market entry by others... would not mitigate Primergy's market power. Thus, under current circumstances we cannot find that the proposed merger would be

consistent with the public interest. (FERC 5/1997, pages 49 and 50, emphasis added, footnotes omitted.)

Whether there will be a market power problem due to environmental regulations will depend on the various conditions of each particular merger. Some of the key factors that should be considered are similar to those that affect market power in the electricity market, including the new company's market share of generation in the region, and transmission constraints in the region. Other key factors to consider include the extent of fossil-fired capacity owned by the merging companies, the current and forecast prices of allowances and offsets, whether the merging companies are both within a region affected by a cap-and-trade system, and whether the merging companies include nonattainment areas. In the following section we investigate some of these conditions in a case study of a recent electric company merger.

## 5.2 Case Study of the FirstEnergy Merger

### Background on the FirstEnergy Merger

The FirstEnergy merger combined the Ohio Edison Company with Centerior Energy, which itself is the result of the combination of the Illuminating Company, Toledo Edison, and Pennsylvania Power Company. The combined company serves a total of 2.2 million customers in a 13,200 square mile service area in central and northern Ohio and western Pennsylvania. FirstEnergy has $5 billion in annual revenues and over $18 billion in assets (FirstEnergy 1999).

Table 5.1 presents a summary of the generation and emissions profile of Ohio Edison, Centerior Energy and the combined FirstEnergy. The merger combined 4,384 MW of coal-fired capacity of Ohio Edison Company with 3,582 MW of coal-fired capacity of Centerior Energy, resulting in a total of 7,966 MW of capacity in the new company.[29] The two companies combined will be the fourth largest electric utility emitter of $SO_2$ emissions the US, and the fifth largest electric utility emitter of $NO_X$ emissions in the US (EPA 2/1999).

**Table 5.1 Summary of Generation and Emission Profiles of FirstEnergy.**

| | Ohio Edison | Centerior | FirstEnergy |
|---|---|---|---|
| Coal Capacity (MW) | 4,384 | 3,582 | 7,966 |
| 1996 $SO_2$ Emissions (tons) | 187,917 | 265,189 | 453,106 |
| 1996 $NO_X$ Emissions (tons) | 73,589 | 70,926 | 144,515 |
| 2000 $SO_2$ Allowances (tons) | 128,601 | 109,056 | 237,657 |
| 2003 $NO_X$ Allowances (tons) | 8,687 | 6,363 | 15,051 |

*Notes and Sources: Capacity data are from FirstEnergy 1999 and NRDC 1997. $SO_2$ and $NO_X$ Emissions are from EPA 2/1999. $SO_2$ allowances are from EPA 9/1998b, and $NO_X$ allowances are from EPA 12/1997. $NO_X$ allowances are only needed for the ozone season, which typically represents 5/12 of a year.*

[29] FirstEnergy has recently proposed to exchange capacity with the Duquesne Light Company. The net effect will be a reduction in FirstEnergy's coal capacity of 554 MW (FirstEnergy 1999). For the sake of simplicity, we have not adjusted the numbers in Table 5.1 to reflect this change.

## Relevant Air Quality Regulations in Pennsylvania and Ohio

All of FirstEnergy's power plants will be subject to the $SO_2$ and $NO_X$ requirements under Title IV, Phase I and Phase II.

Both Pennsylvania and Ohio are among the 22 states that are included in the EPA's SIP Rule, so all of FirstEnergy's fossil plants will likely be affected by the rule. If the SIP Rule is derailed by the current court challenges, all of FirstEnergy's fossil plants by will be subject to the Section 126 Petitions (EPA 12/1998).

Pennsylvania recently completed a draft rule for complying with the EPA SIP Rule, but it has been put on hold until the court challenges to the SIP Rule are resolved. The draft rule includes a new source set-aside that is similar to that proposed in the EPA model rule for $NO_X$ trading. However, there is one important difference in that the Pennsylvania draft rule proposes to allocate $NO_X$ allowances on the lower of the SIP emission limit (0.15 lb/MMBtu) or the unit's permitted emission rate, while the EPA has recommended the allocation be based on the SIP emission limit (PA DEP 9/1999).

Every county in Pennsylvania is, at least, at a moderate level of nonattainment for ozone, and some of the western and eastern counties are in severe nonattainment. This means that NSR provisions will apply to any new power plant located in the state. The Pennsylvania DEP has entered into an MOU with the New York Department of Environmental Conservation that allows for trading of $NO_X$ offsets across the two states (PA DEP 1996). There are no $NO_X$ waivers in Pennsylvania.

Regulators in Ohio have taken a different approach to $NO_X$ regulation than in Pennsylvania. The Ohio Environmental Protection Agency (OH EPA) has essentially rejected the argument that the transport of Ohio $NO_X$ leads to increased ozone in downwind states. Consequently, the OH EPA has opposed the US EPA's proposed SIP Rule. Instead, it plans to focus on achieving the US EPA's proposed eight-hour ozone standard, on the grounds that this standard has more merit and justification than the SIP Rule, and is more likely to withstand the court challenges (Nature Conservancy 1999).

Ohio has supported a $NO_X$ reduction proposal developed along with neighboring states in the Southeast/Midwest Governors Ozone Coalition (the S/M Coalition).[30] This alternative proposal calls for (a) a reduction of $NO_X$ emissions by 55 percent of 1990 levels or 0.35 lb/MMBtu, whichever is less stringent, by April 2002, and (b) a reduction of $NO_X$ emissions by 65 percent of 1990 levels or 0.25 lb/MMBtu, whichever is less stringent, by April 2004. The S/M Coalition also calls for states to seek reductions that will assure the EPA's proposed eight-hour ozone standard can be achieved by the autumn of 2009. Since the alternative proposal does not include a cap on $NO_X$ emissions, it does not include an allowance trading system. However, each state may choose to achieve its own reductions as it prefers (S/M Coalition 1998).

The OH EPA has recommended that a $NO_X$ trading rule be developed to assist in achieving the eight-hour ozone standard. However, this recommendation was made only

[30] This coalition includes the states of Alabama, Michigan, Ohio, Tennessee, Virginia, and West Virginia (S/M Coalition 1998).

recently, and very few details have been discussed. This trading rule is likely to be limited to just Ohio, since the initiative is focused on reducing local $NO_X$ emissions and improving local air quality. There have been no detailed discussions of $NO_X$ allowance allocation strategies, although it appears as though an output-based allocation scheme might be acceptable (Nature Conservancy 1999).

The Cincinnati area is currently in nonattainment of the one-hour ozone ambient air standard. However, the Cincinnati area has been granted a $NO_X$ waiver, under Section 182(f) of the Clean Air Act. (See Section 4.2 for a description of $NO_X$ waivers.) This $NO_X$ waiver, however, does not apply to all power plants – it only applies to those that have a capacity of 500 MW or less. Larger power plants are not subject to the waiver, and will therefore be required to meet NSR standards. Developers have recently announced plans for building three new natural gas combined-cycle units in Ohio – each of which is less than 500 MW and not subject to NSR (Nature Conservancy).

If the EPA were to implement its proposed eight-hour ozone ambient air standard, then all urban areas in Ohio, representing roughly 80 percent of the state, would likely be in nonattainment. In addition, the existing $NO_X$ waiver might be lifted if the eight-hour standard were in place. Implementation of the $NO_X$ SIP Rule (or provisions of the Section 126 Petition) would not affect the $NO_X$ waiver.

### Market Distortions Arising From Allowance Allocations in Pennsylvania and Ohio

As discussed in Section 4.2, the existing federal $SO_2$ allowance allocation scheme will result in the inequitable treatment of new versus existing power plants. The EPA has allocated 128,601 tons of $SO_2$ allowances to the Ohio Edison coal plants, and 109,056 tons for the Centerior coal plants, for each year from 2000 through 2009 (EPA 9/1998b). This means that the combined FirstEnergy will receive a total of 237,657 tons of allowances, representing environmental compliance cost savings of roughly \$47.5 million.[31]

The draft Pennsylvania $NO_X$ allocation scheme would create an inequity between new and existing sources, as a result of the proposal to calculate allowances on the basis of the lower of the SIP emission limit or the unit's permitted emission rate. Under this approach, new sources will be allocated significantly fewer $NO_X$ allowances than existing units, because their permitted rates are much lower than the SIP emission limit. In effect, the new units will be penalized (i.e., given less of a reduction in environmental compliance costs) as a consequence of having installed additional controls and achieved additional reductions.

If the PA DEP were to instead allocate all allowances on the basis of the 0.15 lb/MMBtu SIP emission limit, then there is a risk that a five percent set-aside would be insufficient to cover the needs of all new power developers. As indicated in Table 3.3, power developers have announced as much as 3,900 MW of new capacity for Pennsylvania, which would require roughly 10 percent of all the Pennsylvania $NO_X$ allocations, if the

[31] Here we assume $SO_2$ allowance costs of \$200/ton.

allowances were allocated under this approach. In sum, it appears as though new sources in Pennsylvania will allocated less $NO_X$ allowances than existing sources – either because a different rate is used in the allocation, or because there are not enough set-asides to go around.

It is difficult to predict whether a forthcoming $NO_X$ allocation scheme in Ohio will create inequities between new and existing sources. If the $NO_X$ trading rule that is being considered to assist in meeting the eight-hour ozone standard is limited to only the sources within the state of Ohio, then there is a risk that too large a portion of the allowances would be allocated to the owners of existing power plants. For example, if the EPA $NO_X$ allocation methodology were applied to only the power plants in Ohio, then FirstEnergy would be allocated roughly 23 percent all the Ohio $NO_X$ allowances, potentially creating a market power problem in the allowance market. However, if the Ohio $NO_X$ trading rule allocates allowances on the basis of power plant output, as has been proposed, then there may be a better balance between allowances allocated to existing and new sources.

### Market Distortions Arising From PSD and NSR Requirements in Ohio and Pennsylvania

Because all of Pennsylvania is in nonattainment of the ozone standard, all new power plants must meet NSR requirements, including the installation of LAER controls and the purchasing of $NO_X$ offsets. Existing sources are required to install only RACT controls, and are not required to purchase offsets.

These different requirements create inequities between new and existing sources. First, new sources must pay for greater levels of $NO_X$ control technologies. Second, new sources must purchase $NO_X$ offsets, while existing sources have the opportunity to sell $NO_X$ offsets.

However, there does not appear to be a market power problem in the $NO_X$ offsets market in Pennsylvania. There are currently ample $NO_X$ offsets available from industries and electric utilities in Pennsylvania. In fact, the Pennsylvania Power Company (a subsidiary of FirstEnergy) has recently made 214 tons/year of $NO_X$ offsets available for trading. This is in addition to as much as 4,678 tons/year of $NO_X$ offsets that have recently been made available from other electric companies and other industries in Pennsylvania (PA DEP 7/1999). Furthermore, the MOU between Pennsylvania and New York means that new sources can purchase $NO_X$ offsets from industries and utilities in New York as well.

Many of the $NO_X$ offsets currently available in Pennsylvania are the result of early emissions reductions and banked offsets that cannot be expected to last long into the future. Furthermore, if the EPA implements the eight-hour ozone standard, then the $NO_X$ offset market in Pennsylvania might become tighter and more competitive. Nevertheless, it does not appear as though there is a significant risk of market distortion in the Pennsylvania $NO_X$ offset markets.

The $NO_X$ waiver that currently applies in Ohio means that both new and existing units are subject to PSD requirements. As described above, PSD creates an inequity between new and existing sources, in that new sources are essentially required to install SCR technologies while existing sources are not. Since there is no requirement for $NO_X$ offsets, there is no potential for inequities or market distortions in a $NO_X$ offset market.

### Market Distortions in the Context of the FirstEnergy Merger

With regard to the markets for $SO_2$ and $NO_X$ allowances, the FirstEnergy merger itself is unlikely to create market distortions. This is primarily due to the size of the $SO_2$ allowance market, the size of the $NO_X$ allowance market, and the current lack of $NO_X$ trading requirements in Ohio.

With regard to the $NO_X$ offset market, there is also little chance that the FirstEnergy merger itself would create market distortions. FirstEnergy owns shares of two power plants located in nonattainment areas in Pennsylvania, equaling roughly 2,299 MW of capacity.[32] Given the robustness of today's offset market in Pennsylvania, it is difficult to see how this capacity could provide FirstEnergy with any form of market power in the $NO_X$ offset market there. FirstEnergy does not own any power plants located in the current nonattainment areas in Ohio. Even if it did, the $NO_X$ waiver eliminates the need for a $NO_X$ offset market in Ohio anyway.

As we noted above with the ComEd divestiture, even though the FirstEnergy merger is unlikely to *create* market distortions in the allowance or offset markets, there may be distortions present in those markets that can contribute to market power. Economic inequities can be a barrier to entry – either on their own, or when combined with other factors.

In sum, inconsistent environmental regulations result in the following inequities in FirstEnergy's electricity markets:

- New sources in Pennsylvania and Ohio are required to purchase all of their $SO_2$ allowances, while FirstEnergy is allocated free allowances up to the 1.2 lb/MMBtu level.
- New sources in Pennsylvania are allocated less $NO_X$ allowances than FirstEnergy, because their permitted emission levels are less than the SIP emission limit.
- New sources in Pennsylvania are required to install LAER controls (under NSR), while FirstEnergy is required to install only RACT controls.
- New sources in Ohio are required to install BACT controls (under PSD), while FirstEnergy is required to install RACT controls on its coal units.
- New sources in Pennsylvania are required to purchase $NO_X$ offsets from existing utilities and industries in Pennsylvania and New York. While the availability of $NO_X$ offsets does not appear to be a problem, new sources will still have to incur the up-front costs and financing associated with $NO_X$ offsets.

[32] This includes the Bruce Mansfield and New Castle plants. After the asset transfer agreement with Duquesne is completed, First Energy will own a greater share of the Mansfield plant and none of the New Castle plant. The resulting capacity in PA will be 2,361 MW (FirstEnergy 1999).

A thorough market power analysis must consider the barriers to entry created by these inequities, in order to fully assess the competitiveness of the markets being analyzed. When FERC reviewed the FirstEnergy merger application, it found that "the merger may have an adverse effect on competition" in the region (FERC 7/1997). FirstEnergy attempted to address these market power concerns by submitting a new application with modifications to its market power analysis and to its merger proposal. FERC subsequently found that FirstEnergy's revised market power analysis continued to indicate that the proposed merger would result in excessive levels of market power (FERC 10/1997). FERC approved the revised merger proposal, however, on the condition that FirstEnergy undertake a number of market power mitigation measures (mostly related to the separation of transmission and generation operations). In reviewing FirstEnergy's market power analyses, FERC did not consider the barriers to entry that are created by inconsistent environmental regulations.

This appears to be a merger that could potentially result in excessive market power – i.e., it is a "marginal" case where market power problems could arise depending upon a number of factors such as the effectiveness of FirstEnergy's mitigation measures. In such a case, it would clearly be important to consider barriers to entry caused by environmental regulations, because such barriers might turn a case of marginal market power into a case of excessive market power.

# 6. Market Distortions in the Context of New Power Plant Development

## 6.1 Overview

All other things being equal, the requirement for NSR offsets is more likely to cause market distortions than are cap and trade programs. There are three primary reasons for this. First, new entrants must purchase offsets from incumbent companies, some or all of which may be competitors. Second, there are greater geographic restrictions on the purchase and sale of NSR offsets. Third, the supply of NSR offsets is usually tighter than the supply of $SO_2$ or $NO_X$ allowances, because offsets must be created in nonattainment areas where emission standards are stringent and offsets must represent permanent emission reductions.

In addition, the exercise of market power in offsets markets may be harder to detect than in allowance markets. For example, an existing company that have the potential to create offsets may choose not to do so, because the only potential buyers would be competitors. In this case, there would be no obvious hoarding of offsets. The result would simply be a reduced supply of offsets and higher prices.

As discussed in Section 3.3, the presence and severity of market distortions associated with offsets will be a function of several factors. These factors include (a) the number of firms with large emission sources in a given area, (b) the distribution of these sources across different industries, (c) the geographic sizes of the nonattainment area and the market in which the firms compete, (d) transmission constraints in the region, and unique rules in the state or local regulatory framework.

The two case studies below serve to illustrate how these factors can lead to or mitigate market distortions in both offsets markets and electricity markets.

## 6.2 Beaumont/Port Arthur, Texas

In 1998, the chemicals company, BASF, and petroleum refiner, FINA, began seeking roughly 1,400 offsets to cover emissions from a joint venture the companies are developing at an existing FINA facility in Port Arthur, Texas. The centerpiece of the new facility is a large "steam cracker," a process used in both chemical manufacture and petroleum refining.

The Beaumont/Port Arthur area is in severe nonattainment of the NAAQS for ozone. Initially, BASF/FINA found few offsets available in the Beaumont/Port Arthur nonattainment area. Broadening their search, the companies investigated whether offsets could be brought into Beaumont/Port Arthur from other areas, and found that, indeed, they could be.

## Inter-Domain Trading in Texas

The Texas Natural Resource Conservation Commission's (TNRCC) draft guidance document for emission banking and trading includes a provision for the transfer of offsets from one nonattainment area to another, provided three conditions are met. First, the reductions must be generated in an area with a nonattainment classification equal to or higher than the area in which they are used. Second, a demonstration of transport must be made to show that emissions from the area in which the reductions are generated contribute to nonattainment in the area of use. For VOCs, offsets must be obtained within a distance of 100 km; for $NO_x$, offsets must be obtained within 200 km. Third, the Executive Director of TNRCC must give prior approval of the trade (TNRCC 1999).

These criteria essentially allow for the transfer of offsets only from the Houston/Galveston nonattainment area to the Beaumont/Port Arthur area. When such transfers are made, the higher offset ratio from the Houston/Galveston area must be used. In other words, offsets obtained in Houston for use on Beaumont must be obtained at a ratio of 1.3 to 1, not the 1.15 to 1 ratio applicable to the Beaumont/Port Arthur area. The draft guidance document also provides guidelines for demonstrating transport.

Staff at the TNRCC are careful to point out that this provision for inter-domain trading of offsets is based on the fact that emissions from Houston/Galveston impact air quality in Beaumont/Port Arthur, not on offset supply or demand conditions in either area. From the perspective of offset markets, inter-domain trading increases the potential number of suppliers of offsets to facilities in the Beaumont/Port Arthur area.

## Two Aspects of Market Size

Ultimately, the BASF/FINA project obtained offsets from sources in the Beaumont/Port Arthur area. The offsets were provided by several oil refineries, with the vast majority of the offsets coming from Clark Refining and Marketing, Inc., a competitor of FINA's. Clark did not see a competitive concern with selling offsets to the BASF/FINA project for several reasons. First, BASF/FINA had stated its intentions to use the steam cracker primarily for chemical production, not petroleum refining – the market in which Clark competes with FINA (Clark 1999). However, with the new steam cracker located at an existing FINA facility, Clark had to consider the possibility that it would be used for petroleum refining at some point in the future. In considering this possibility, two aspects of market size were key considerations.

First, Clark executives believed that the BASF/FINA project would be able to acquire offsets and enter the market, regardless of whether or not Clark sold them offsets. The fact that the BASF/FINA project had two nonattainment areas in which to seek offsets probably played a role in Clark's conclusion on this point. However, the size of the *petroleum refining market* played an equally important role in the decision (Clark 1999). The refining industry is essentially global, not regional, and in an industry of this size, the addition of a single additional plant is not likely to affect prices. Clark may have concluded that, even if the BASF/FINA steam cracker were used for petroleum refining, there would be no resulting revenue losses – or if there were, they would be small compared to the revenue from the sale of offsets.

The BASF/FINA refinery did not experience market power problems in the offsets market, in part, because of the large size of the chemical production and petroleum refining markets. The electricity market differs from the markets for chemical production and petroleum refining, however, because of the physical limitations on the geographic size of the market. While many products can be shipped at costs low enough to make markets quite large (consider petroleum, steel or lumber), line losses and congestion on transmission systems place limits on the distance over which electricity can be transmitted. The next case study describes an offset market that is subject to market power problems, primarily because of the unusually small size of the electricity market involved.

## 6.3 The San Diego Air Pollution Control District

San Diego County is perhaps the most difficult place in the country to site a new power plant. During the past several years, the problem has been the unique regulatory treatment of the existing power plants in the county. After the year 2000, this regulatory program will end, but siting power plants will continue to be difficult because offsets are extremely scarce. These market-entry conditions are already resulting in above-market revenues for existing power plants, as they are compensated for providing capacity in a region where capacity margins are thinning. Eventually, these conditions could affect reliability in the region as well, as demand grows and transmission constraints limit the amount of power that can be imported into the area.

### Rule 69

In 1994, the San Diego Air Pollution Control District (SDAPCD) adopted "Rule 69," governing air emissions from, among other sources, the three utility-owned power plants in San Diego County.[33] In an effort to provide San Diego Gas & Electric (SDG&E) with flexibility in reducing emissions from these plants, Rule 69 established a declining cap on emissions of $NO_x$ from these three plants, allowing the utility to select the units to control to meet the cap. In 1996, SDG&E retired one of the facilities, leaving only the South Bay and Encina power plants under the cap. The cap became enforceable in 1997, allowing a total of 2,100 tons per year. In 2001 the cap was to decline to 800 tons per year, and in 2005, to 650 tons per year. These emissions were essentially "set aside" for electricity generation in the District's air compliance plan.

This regional emission cap, however, was not accompanied by an allowance trading program. The two generating units were simply regulated as a single unit, with a single ton-per-year emission rate. While this arrangement may have been appropriate in the context of a monopoly electric industry, it is highly problematic in an industry moving to competition, because there is no mechanism by which these pollution rights can be transferred to a new facility. Under Rule 69 it was virtually impossible for another

[33] In California the State air agency, the California Air Resources Board (CARB) oversees some 38 regional air districts. These regional districts are responsible for regulating stationary sources in accordance with guidelines established by CARB. CARB takes the lead in regulating mobile sources in the state.

company to build a power plant in San Diego County, because all of the emissions set aside for power generation were "owned" by SDG&E.[34]

However, Rule 69 also provides for a change in this regulatory program if either of the power plants under the cap were sold to a company not affiliated with SDG&E. With the sale of any plant, the Rule requires the plant sold to meet an emission rate of 0.15 lb/MWh and requires the cap for the remaining plant to be reduced by an appropriate amount. In May 1999, SDG&E sold both plants. As a result, both facilities will have to achieve the 0.15 lb/MWh emission rate by January of 2000. At this time the cap requirement will end. (However, the new owners of both South Bay and Encina have requested variances from this aspect of Rule 69, requesting that the cap be retained and apportioned between them.)

### Offsets in SDAPCD

However, when the cap is deleted, the problems for developers of new power plants in San Diego will not be over, because offsets are so scarce. The primary reasons for this scarcity are the small number of large, stationary $NO_x$ sources in the County and the stringency of the existing $NO_x$ emission requirements.[35] As of September 1999, there were 95.5 tons per year of $NO_x$ offsets in the SDAPCD registry. However, virtually none of these offsets are available for sale, as their owners intend to hold them for them for their own potential future use. As calculated in Section 3.5, a 400-MW gas-fired power plant emitting $NO_x$ at 0.02 lb/MMBtu would need roughly 163 tons per year of $NO_x$ offsets.[36]

Currently, the market for $NO_x$ offsets in San Diego County is not robust enough even to provide reliable price signals. One recent trade reportedly took place at $32,500 per ton/year, but these offsets are likely to be discounted heavily, resulting in a higher actual price per ton (Cantor 1999). Other trades are reported to have taken place at prices in excess of $50,000 per ton/year. However, even at these prices, the cost of offsets is not the barrier to market entry; it is the fact that there simply are no offsets to be bought.[37]

In the face of San Diego's extremely tight offset market, there has been increasing interest in the creation of offsets in other ways. Other options include inter-pollutant trading (e.g., the creation of $NO_x$ offsets from VOC reductions), inter-basin trading (i.e.,

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34 When Rule 69 was being adopted, several intervenors argued that market power was being bestowed on SDG&E in that the company was being granted all of the pollution rights set aside for electric generating in the District. In response, SDAPCD asserted that review of market power concerns properly fell under the jurisdiction of the Public Utilities Commission and the California Energy Commission.

35 There are only three facilities with the potential to emit 100 tons of $NO_x$ per year or more – including the South Bay and Encina power plants. The third large source, as well as many other sources, have shown no interest in overcontroling their emissions, preferring to retain any potential reductions or offsets for their own use.

36 Note that a new combined-cycle gas plant would emit roughly one seventh of the NOx that will be emitted by either of the (simple-cycle) South Bay or Encina plants after controls are added to them.

37 At $32,500 per ton, offsets for a 400 MW plant would cost a total of 5.3 million dollars. At a capital recovery factor if 10 percent per year, this would add a cost of $0.23 per MWh.

the use of offsets created in other pollution control districts), and the creation of offsets from mobile source emission reductions.

Several of the air districts in California, including SDAPCD, have established policies governing inter-pollutant trading. These policies were developed in consultation with the districts' parent agency, the California Air Resources Board (CARB). Based on the relative contributions of $NO_x$ and VOCs to smog formation in San Diego County, SDAPCD allows the creation of one $NO_x$ offset from two VOC offsets.[38] With 263 VOC offsets in the registry, this would allow for 131.5 $NO_x$ offsets. This, however, assumes that all owners of VOCs offsets in the County are willing sellers, and this is clearly not the case. One source estimates that 50 to 60 of these offsets could be purchased at prices in the range of $50,000 per ton/year ($100,000 per $NO_x$ offset).

Trading among nonattainment areas in California, known as "inter-basin" trading, is allowed, subject to rules developed by CARB.[39] According to these rules, offsets are discounted based on distance and can only be obtained from areas that can be shown to contribute to air pollution in the region of use. When obtaining offsets from a location within 50 miles of a given basin, two credits are required to offset one ton of $NO_x$. With each additional 25 miles, an additional credit is needed to offset one ton of $NO_x$. (For example, at 75 miles, three credits are needed to offset a ton. At 100 miles, four offsets are needed.) However, based on prevailing patterns of pollution transport, the South Coast Air Quality Management District (South Coast) is the only air district from which offsets can be brought into SDAPCD, and officials in the South Coast require an additional discount to compensate for the loss of economic development potential in that area. The added discount required by South Coast brings the overall discount ratio to roughly 10 to 1 for bringing offsets to SDAPCD from South Coast.

The use of mobile source offsets for a stationary source is also an option, but this would be difficult. To date, regulators have not been able to agree on how mobile source emission reductions can be shown to be "permanent" and "enforceable." For example, the permanence of an offset relies on the documentation of the reduction in an operating permit. Since mobile sources are not required to have air permits, it is difficult to gauge the permanence of mobile source emission reductions. The SDAPCD has proposed rules for the creation of offsets from mobile sources to CARB and EPA, but neither agency has yet approved the rules. EPA in particular has expressed concern over SDAPCD's proposed methodology for calculating reductions and its assumptions about the permanence of reductions (SDAPC 1990).

## Market Distortions Associated with Offsets in SDAPCD

The cap on emissions from power plants contained in Rule 69 represents a serious market distortion. It gives the two existing power plants a monopoly on emission rights in the

[38] Note that EPA recently remanded this section of the SDAPCD NSR rule for further study, citing insufficient evidence for a blanket 2:1 ratio.

[39] CARB recently released a formal guidance document to aid air districts in developing policies for inter-pollutant and inter-basin trading. The document, *Guidance for Power Plant Siting and Best Available Control Technology*, is available at: www.arb.ca.gov. Note that while offsets have been traded between basins in California, EPA has not yet approved CARB's guidelines on inter-basin trading.

region, essentially preventing new entrants from entering the market. The removal of the cap, in January of 2000, would represent a step toward a more competitive electric industry in region, but for the foreseeable future the industry will be far from competitive, because offsets are virtually impossible to acquire. Transmission constraints (and the Pacific Ocean and Mexican border) severely limit potential electricity imports into SDAPCD, and capacity margins are thinning. The existing power plants in the County receive extra capacity payments from the California ISO ("reliability must run" or "RMR" payments) by virtue of their location in the transmission-constrained area. The situation in SDAPCD is clearly a case in which environmental regulations are resulting in market distortions.

There are at least three points at which the California PUC and/or FERC could have identified the market distortions in San Diego. First, between 1995 and 1998 the PUC was engaged in the process of establishing a competitive market for electricity. During this process, the PUC conducted a market power study, and, based on the conclusions of that study, required Southern California Edison and Pacific Gas & Electric to divest half of their generating portfolios. This strategy for the mitigation of market power in the State was accepted by FERC. Restricted market entry in SDAPCD was not addressed by the PUC or FERC, although several parties raised the issue – and in adopting the Rule 69 emissions cap, SDAPCD has stated explicitly that it was relying on the PUC to review concerns about market power.

The second point at which this market distortion could have been identified and mitigated was SDG&E's recent merger with Southern California Gas. As discussed in Chapter 5, both FERC and state energy regulators must review the anti-competitive implications of any merger. While the market distortions discussed here are not a product of the SDG&E/Southern California Gas merger, the distortions would be hard to miss in a market power analysis of the region. During the review of the merger, either FERC, the PUC, or both should have identified the need for energy and environmental regulators to devise a solution to the market entry problems in San Diego County.

Finally, when the South Bay and Encina plants were sold, SDG&E was required to make an "851 filing," petitioning the PUC for the ability to sell ratepayer-owned assets. This filing represents another point at which the PUC could have identified the market entry problem in San Diego. However, in none of these three proceedings did the PUC or FERC recommend action.

What should energy regulators have recommended in order to facilitate market entry in the San Diego electricity market? There is no single solution to local market distortions created by environmental regulations, transmission constraints or any other factor. In each case, energy and environmental regulators need to work together to develop an equitable solution that creates as competitive a market as possible while preserving the goals of the environmental regulations at issue. Especially in areas with severe air-quality problems, such as San Diego, it is important that solutions to market distortions do not come at the expense of air quality. However, in most cases, solutions exist that preserve environmental goals and mitigate to some degree the market distortion.

One fairly simple solution in San Diego would be a reallocation of the pollution rights set aside for electricity generation by SDAPCD. When the South Bay and Encina plants reduce their emissions to 0.15 lb/MWh, this will free up a considerable number of $NO_x$ tons, even under the final cap of 650 tons per year, scheduled to take effect in 2005. The District could make these offsets available to new entrants via auction. (This would not be unprecedented; state agencies in some nonattainment areas set aside or provide a portion of offsets for new projects in the name of economic development.)

Whatever the solution, the important conclusion is that both energy and environmental regulators must be aware of the potential for environmental regulations to contribute to market distortions, and they must be willing to work together to develop appropriate solutions when these distortions are identified.

# 7. Options for Mitigating Market Distortions

## 7.1 Rationale for Mitigating Market Distortions

There is no basis in economic theory for treating new sources differently from existing sources when designing environmental regulations (Synapse 6/1998). In fact, grandfathering is often economically inefficient because it provides a competitive advantage to existing industries and firms, thereby hindering new competitors and opportunities for innovation. It is also inconsistent with the widely-accepted "polluter pays principle," which requires that firms that cause environmental damage pay for prevention or remedial costs. This principle promotes efficient economic decisions regarding pollution production and prevention, and also promotes equity between competing firms.

The primary justification for applying less stringent regulations to existing polluters is that it is often necessary in order to win political acceptance of the new regulations. In debates about new regulations, there tends to be substantial and aggressive participation from the representatives of the existing polluters, while the representatives of new market entrants tend to have much less political clout, if any. Consequently, regulations often favor existing polluters at the expense of new entrants.

Such political favoritism was less problematic during the $SO_2$ debate of the 1980's, because the electricity industry was regulated and there was little concern about introducing and maintaining a workably competitive electricity market. Under current industry conditions, however, it is crucial that both environmental and economic regulators work to assure workably competitive electricity markets. If new entrants are not allowed sufficient access to the electricity market, then the introduction of newer, more efficient, less polluting generating facilities will be delayed, and the goals of both the environmental regulators and economic regulators will be thwarted.

Furthermore, it is important to recognize that the cumulative effect of new regulations may increase their negative impact on electricity markets. During the debate over $SO_2$ allowances, the inequitable allocation scheme might have been justified on the grounds that the impact on the electricity market would be relatively small. However, the $SO_2$ allowance inequity may now be added to inequities in $NO_X$ allowance schemes, and inequities related to NSR requirements. Furthermore, these market distortions might be compounded by those of future environmental regulations, such as those associated with $CO_2$, air toxics, regional haze or particulate matter.

## 7.2 The EPA SIP Rule

The EPA SIP Rule would eliminate a significant portion the difference in $NO_X$ regulations that are applied to new versus existing power plants. As indicated in Figure 3.1, the SIP Rule emission limit of 0.15 lb/MMBtu is substantially lower than the range of emission rates required of existing coal units under Phase II of Title IV.

However, even if the SIP Rule were to be implemented, there would continue to be a large difference between emission requirements of new and existing units. The SIP emission limit is still roughly seven to fifteen times less stringent than typical $NO_X$ emission rates from new natural gas combined-cycle units with low-NOx combustion technology and SCR.

In addition, in some states new sources might be placed at a disadvantage relative to existing sources because some states have not set aside enough allowances for new sources, as described in Section 3.4. Furthermore, there are 26 states in the continental US that are not subject to the EPA SIP Rule.

## 7.3 Allowance Allocation Schemes

The economic inequities created by the $SO_2$ and $NO_X$ cap-and-trade programs could be eliminated by changing the way that allowances are allocated. There are many important issues to consider in designing allowance allocation schemes. Many of these issues, described below, affect four problematic aspects of the current approach to allocation: (a) allowances are allocated based on historic, not current, plant utilization; (b) allowances are allocated based on heat input, not electricity output; (c) allowances are not allocated equitably to new sources; and (d) allowances are not allocated equitably to renewable or end-use efficiency resources.

### Input-Based Versus Output-based Allocations Schemes

Allowances can be allocated to electric generators either on the basis of the heat content of the fuel consumed (i.e., input-based, in terms of MMBtu), or on the basis of the amount to electricity generated (i.e., output-based, in terms of MWh). The primary disadvantage of input-based systems is that they reward power plant owners for inefficient operation. Plants that burn large quantities of fuel receive more allowances, regardless of the amount of electricity they generate.

In contrast, output-based allocation schemes provide a clear monetary incentive to maximize efficiency. Plant owners that burn less fuel per MWh, and thereby emit less pollution per MWh, would not be penalized by earning less allowances. Instead, they would receive the same amount of allowances, and could sell excess allowances that are created through more efficient operation. The incentive to promote efficient power plant operation would help reduce environmental impacts of electricity generation – not just for the pollutant that is regulated by the cap-and-trade system, but also for other pollutants such as $CO_2$ and air toxics.

In developing the $NO_X$ Budget Trading Program, the EPA debated the advantages and disadvantages of input-based versus output-based allocation schemes. The EPA's model rule recommends that states use an input-base allocation system, because the output-based approach had not been fully developed or made available for public comment. However, the EPA appears to be moving towards an output-based approach. The EPA notes that it would support a decision by a state to use either an input-based or an output-based approach. The EPA also notes that it is continuing to work on developing an output-based allocation approach, and that it plans to finalize an output-based approach in 2000 (EPA 10/98).

In addition, state environmental agencies are beginning to recognize the efficiency benefits of output-based allocation schemes. Both Massachusetts and New Jersey have recently established $NO_X$ allocation systems that are based on generation output. Output-based performance standards have also been proposed in several federal bills.[40]

### Permanent Versus Updating Allocation Schemes

Allowances can be allocated on either a permanent basis or through a system that is periodically updated. The $SO_2$ allowance scheme is an example of a permanent system. Generation companies are allocated $SO_2$ allowances on the basis of historical plant operation from 1985 through 1987. These allocations do not change in future years, regardless of whether or how much the plants operate.

Alternatively, allowance allocations can be updated over time to reflect changing plant operations and new entrants to the electricity market. The EPA's $NO_X$ Budget Trading Program is an example of an updating allocation system. The EPA recommends a three-year period between determining the allowances and allocating them, in order to provide generation companies with sufficient time to develop the most cost-effective compliance plans.

Permanent systems are relatively simple to implement and they provide a great deal of predictability regarding the amount of allowances to be allocated to generation companies. However, permanent systems suffer from three main problems. First, they run the risk of allocating allowances based on operation levels that are no longer relevant. Second, input-based permanent allocation systems reward generation companies for inefficient operation that occurred during the baseline period. Third, they do not necessarily provide allowances for new sources that enter the market after the baseline period. The only way to provide allowances to new sources under a permanent system is through set-asides, which have their own problems as described below.

The choice of permanent versus updating allocation schemes has important implications regarding the dispatch of generation units. Under a permanent allocation system, power plant owners can be expected to include the cost of allowances in their bid price. As a result, power plants will be dispatched according to the sum of their fuel, O&M and allowance costs, and the market price for electricity will be increased by the cost of allowances. In this way, the electricity market price will internalize some of the external, environmental costs associated with the pollutant.

Under an updating allocation system, however, power plant owners will not be inclined to include the cost of allowances in their price bid. Updating allocation systems allow power plant owners to earn additional allowances for higher levels of plant operation on an on-going basis. Consequently, higher generation will lead to additional allowances

[40] These bills include: H.R. 2645 (Kucinich), S. 1369 (Jeffords), H.R. 2569 (Pallone), H.R. 657 (Sweeny) and S. 172 (Moynihan).

that will offset the cost of allowances incurred at the time of generation.[41] Therefore, under an updating allocation system, the cost of pollution allowances will not be reflected in power plant dispatch or in the market price for electricity. This has important implications for renewable resources and other new, clean generation sources.

The choice of permanent versus updating allocation systems might affect decisions regarding power plant construction, depending upon other factors in the allocation system design. Permanent allocation systems will increase the market price for electricity, thereby improving the economics of new power plant construction. Updating allocation systems do not provide such an economic advantage for new power plants. However, if the allowance allocation system provides allowances for new generation sources, then the new sources can count on the revenue stream to improve their economics. As long as the potential revenues from new source allowances under an updating scheme is roughly equivalent to the potential revenues from increased market prices under a permanent scheme, then the decision about whether to construct a new plant is not affected by the choice of permanent versus updating allocation scheme.

One of the challenges of an updating system is in determining the appropriate amount of allowances to allocate on the basis of actual operation. Because the number of allowances a plant receives or requires is a function of its production in the current year, allowances must either be allocated retrospectively or the allocation must be estimated in advance. Under a retrospective approach (as proposed in S. 172 and H.R. 657), all companies would know in advance the target emission rate and would operate their plants accordingly. At the year's end, allowances would be allocated, and there would be a trading period before compliance was required. Using the estimation approach (as in H.R. 2509, H.R. 2645 and S. 1369), the output of each plant would be estimated for the coming year, and allowances would be allocated based on this estimation at the beginning of the year.

### Generation Performance Standards

A GPS is an output-based standard that is updated periodically. An emission standard (in lb/MWh) is developed by dividing a desired emission cap by the total amount of generation from relevant electricity resources. All relevant electricity resources are then allocated allowances using this same emission rate. In this way, GPS mechanisms treat new and existing power plants equitably.

The term "generation performance standard" is sometimes used to describe a different regulatory mechanism. The Northeast States for Coordinated Air Use Management (NESCAUM) is developing a model rule for a GPS that applies to all retail suppliers of electricity (as opposed to power plant owners). Retail suppliers are required to meet the same output-based emission standards for $SO_2$, $NO_X$ and $CO_2$, regardless of where the relevant generation source is located. The NESCAUM GPS model rule does not introduce a new allowance or credit trading system.

[41] The value of future allowances will have to be discounted by plant owners for the number of years that intervene between plant operation and allowance allocation. However, the value of allowances might increase over time, potentially offsetting this discounting effect.

## New Source Set-Asides

One way to reduce the inequities between existing and new plants is to create allowance set-asides for new plants. Set-asides are particularly important under permanent allocation schemes, because there is no other way for new sources to obtain free allowances as they enter the market over time. New source set-asides are also important in updating allocation schemes that include a lag period. For example, the EPA's $NO_X$ Budget Trading Program is an updating allocation system, but it includes built-in lag periods. In the early years of the program (2003 through 2005), allowances are only allocated to those units that were operating prior to May 1995. In the later years of the program there is still a lag period of three years between the time a power plant operates and the time it is awarded allowances. This lag period is why EPA has proposed new source set-asides as a part of its $NO_X$ Budget Trading Program.

However, new source set-asides suffer from three important problems. The first problem arises from the challenge of deciding what portion of total allowances to set aside. It is very difficult to determine ahead of time how many allowances will be needed by new sources. As described in Section 3.4, EPA's proposal for a five percent new source set-aside is not likely to be the right amount in many states, since the proper set-aside amount will be affected by (a) the amount of growth in electricity demand, (b) the amount of capacity reserves, and (c) the interest of power plant developers in locating in a given area. One way to compensate for this uncertainty is to overestimate the amount of set-asides needed. However, this approach may not be politically acceptable and may cause uncertainty among the existing sources that receive allowance allocations.

The second problem with new source set-asides arises from the temptation to provide them at a lower rate than what is provided to existing sources. As described in Section 3.4, some states have decided to allocate $NO_X$ new source set-asides on the basis of the permitted $NO_X$ emission rate of the new unit, as opposed to the higher emission rate that is used to allocate allowances to existing sources. As indicated in Table 3.1 and Figure 3.1, permitted emission rates (in lb/MWh) for new gas combined-cycle units can be as much as twenty to forty times lower than the emission rate imposed on existing units by the EPA SIP Rule.

The rationale for providing allowances based on the permitted rate, presumably, is that that amount is sufficient to cover the allowance needs of the new sources. However this approach does not account for the direct and indirect environmental compliance costs that new sources incur. Consequently, new sources are still at a disadvantage relative to existing sources under this approach. If new sources were allocated an amount of allowances equal to what existing sources are allocated, then they could sell the extra allowances to offset some of the direct and indirect compliance costs. The EPA has noted the importance of maintaining equity between new and existing sources this way in its $NO_X$ Budget Trading Program, but many states have chosen to disregard the EPA's recommendation.

The third problem with new source set-asides is that by their very nature they imply that new sources should be treated differently than existing sources. In fact, new sources should be treated exactly the same as existing sources – in order to truly eliminate any inequities. Having a set-aside where allowances are calculated differently creates opportunities for reducing the amount of allowances that go to new sources, or otherwise undermining the goal of new source set-asides. A set-aside might suggest to some that new sources are receiving a bonus that they are not necessarily entitled to but is necessary to achieve political acceptance of the allocation system. If fact, the opposite is true – new sources should have just as much right to allowances, on an equitable basis, as existing sources.

In sum, including new source set-asides in allowance allocation programs would be a step in the right direction. However, an inclusive allocation scheme, discussed below, offers a more effective and equitable overall solution.

### Renewable and End-Use Efficiency Set-Asides

Although much of this report has focused on the competition between existing generation resources and new natural gas combined-cycle units, many of the same conclusions pertain to renewable resources. That is, renewable resources should be entitled to receive emission allowances in the same way that existing and new fossil units do. Renewable resources represent an important means of reducing emissions (of the pollutant in question and of other pollutants as well), and therefore could be promoted through the emission allocation scheme (Wooley 1999).

In general, renewable resources are at a disadvantage relative to fossil power plants because the price of electricity does not fully account for their environmental benefits. Owners of renewable resources pay higher construction costs in order to obtain the associated environmental benefits, but are not necessarily able to charge higher prices to recover these higher costs. Allocating pollution allowances to renewable resources helps to reduce this disadvantage. It represents one means of compensating them for their additional costs and their contribution to reduced environmental impacts.

Renewable resources could be allocated allowances on the same basis as existing and new sources. This requires allocating allowances on an output-basis, because most renewable resources do not require heat input to generate electricity. This is an additional reason why output-based allocation schemes are more equitable and efficient that input-based schemes – they allow for equitable allocation regardless of how the electricity is generated.

The rationale for allocating allowances to renewable resources is the same as the rationale for allocating allowances to new sources using the same rate as for existing sources (as opposed to using the permitted rate of the new source). In the case of renewables, all of the allowances received can be sold by the owner to help offset additional costs associated with the cleaner resources. A system that does not allocate allowances equitably to either new sources or renewable resources essentially rewards existing units for their higher level of emissions. The rationale that the EPA uses for promoting equitable treatment of new sources applies to renewables as well.

These same arguments can also be used to justify the allocation of allowances to end-use energy efficiency resources as well as renewables.[42] Each MWh of electricity that is avoided through end-use energy efficiency could be allocated allowances to offset the costs of implementation. Each MWh would be allocated allowances on the same basis as existing units, new fossil units, and renewable resources. Allowances would be allocated on an output basis, in order to ensure consistency across all resource types. End-use efficiency resources create some unique challenges with regard to monitoring and enforcement, but these can be addressed with existing policies and practices.

Allowance allocations could have a significant effect on the operating economics of efficiency and renewable resources. $SO_2$ allowances could be worth as much as $1.2/MWh, and $NO_X$ allowances as much as $2.2/MWh, for a total of roughly $3.4/MWh.[43] This total is roughly ten percent of the market price for electricity and thus could improve the economic viability of some projects. If a similar approach were eventually used for $CO_2$ emission allowances, then the combined effect will certainly assist with the introduction of new renewable and efficiency resources.

The Clean Air Act recognizes the importance of renewables and end-use efficiency in meeting the goals of the Acid Rain Program, by establishing a Conservation and Renewable Energy Reserve (CRER). The CRER included 240,000 $SO_2$ allowances that were set-aside for end-use efficiency and 60,000 $SO_2$ allowances set-aside for renewable resources. However, the CRER has been underutilized – as of June 1999 less than twelve percent of the allowances available had been allocated (Wooley 1999). One of the reasons that the CRER has been underutilized is that it contains restrictions on how to earn allowances, e.g., allowances could only be earned by utilities that engaged in least-cost planning. In the years since the 1990 Clean Air Act Amendments, utility least-cost planning has declined substantially, and non-utility generation companies have become more prominent as developers of renewable resources. This is an example of the dangers of set-asides, described above.

Another reason the CRER was underutilized is that the $SO_2$ allowances turned out to have lower market value than expected. Perhaps if $SO_2$ allowances are allocated with $NO_X$ allowances, the combined value would have more of an impact on the market for end-use efficiency and renewable resources.

The EPA's $NO_X$ Budget Trading Program includes a set-aside for end-use efficiency and renewable resources. The EPA recommends that states set aside five to fifteen percent of total $NO_X$ allowances for efficiency and renewable resources. The EPA estimates that such a five percent set-aside in the 22-state $NO_X$ SIP Rule region would result in (a) a reduction in 2003 electricity demand of over 90,000 GWh; (b) roughly $5.0 billion in

[42] This rationale cannot be used to justify the allocation of allowances to nuclear generation sources. While nuclear sources might have lower emissions of the pollutant subject to the cap-and-trade program, they are responsible for other pollutants that are not fully accounted for by regulations (e.g., the generation of nuclear waste).

[43] Here we assume that $SO_2$ allowances are allocated at a rate of 12 lb/MWh and are worth 200 $/ton, and that $NO_X$ allowances are allocated at a rate of 1.5 lb/MWh and are worth 3,000 $/ton.

2003 energy bill savings; (c) a reduction in 2003 compliance costs of $150 million; and (d) roughly 20,000 new jobs throughout the region (EPA 3/1999).

State environmental agencies are also recognizing the need to provide allowances to renewable and end-use efficiency resources. The recently developed Massachusetts $NO_X$ cap-and-trade program includes a one percent set-aside for efficiency and renewables, where the allowances are allocated on the same basis as fossil units, i.e., using a $NO_X$ rate of 1.5 lb/MWh. New Jersey has also established an incentive for efficiency and renewables in its $NO_X$ cap-and-trade system, where allowances are allocated using a $NO_X$ rate of 1.5 lb/MWh. New York also set up a $NO_X$ cap-and-trade system, where three percent of budgeted allowances are set aside for efficiency and renewable resources (Wooley 1999).

While these efforts to allocate allowances to efficiency and renewable resources are an important step in the right direction, as set-asides they might suffer from some of the problems described above regarding new source set-asides. It is difficult to determine what percent of the total allocations will be needed for efficiency and renewables. Is one percent sufficient? Is three percent? As experience with the CRER indicates, restrictions that are put on set-asides can sometimes limit their use and undermine their goals. This is why inclusive allocation schemes can be more effective and equitable, as described below.

### Inclusive Allocation Schemes

An inclusive allocation scheme is one that simply addresses all relevant electricity resources equally – without using set-asides. Existing sources, new fossil units, end-use efficiency and renewable resources would all be allocated allowances using the same rate (in lb/MWh). The rate would be determined by dividing the total desired cap on emissions by the total amount of generation from all of these resources. For example, if this rate turned out to be 1.3 lb/MWh of $NO_X$ under the EPA $NO_X$ SIP Rule, then each of the affected resources would be allocated allowances equal to 1.3 lbs of emissions for each MWh of generation (or avoided generation in the case of end-use efficiency). The fact that some of the resources have emission rates lower than the allocation rate, or no emissions at all, is irrelevant. Under this approach, all appropriate electricity resources would receive allowances on an equitable basis.

Allowances would be allocated on an output basis to promote generation efficiency and account for the fact that some renewable and end-use efficiency resources do not have heat inputs. Allowances would be updated, as opposed to permanent, to avoid the need for set-asides for new units.

Inclusive allocation schemes would allocate allowances to a greater number of market participants, relative to those that focus on existing units. This will in turn reduce the amount of allowances available to existing sources, because of the total cap on pollutants.

### Allowance Auctions

Periodic auctions could be used to distribute emission allowances, instead of using direct allocation schemes. All interested parties – both existing sources and developers of new sources – could be allowed to participate in the auctions. Auctions could be run by a government agency, or by an independent organization, with administration costs covered by a portion of the proceeds of the allowance sales.

The auction approach would solve many of the problems associated with existing allocation schemes. First, an auction of output-based allowances would not reward inefficient plants. A more efficient plant would have a lower allowance cost per MWh of output. Second, it would ensure that all market actors – old and new – had equal access to allowances at the same time and for the same cost. Third, it would not automatically provide allowances to plants that operated in a historical baseline year.

End-use efficiency and renewable resources would not be required to purchase allowances, and would not be allocated any. They would benefit from this system, however, to the extent that the market price for electricity is increased by the cost of allowances, as determined by the auction. Finally, auctions would also reduce the risk that owners of existing generation capacity could create market power problems by accumulating too large of a share of the allowance market.

Auctions raise an important policy question regarding what to do with the revenues raised. If the revenues are allocated back to the power plants subject to the cap-and-trade system, then the auction can be made to be identical to the allowance allocation schemes described above. Another option is to use the revenues raised, or a portion of those revenues, to support research, development, commercialization and implementation of clean resources such as renewables and end-use efficiency. If there is insufficient political support to adopt an auction approach, another option would be to hold auctions for a pre-determined portion of the total allowance budget (CCAP 1999).

## Summary of Prominent Allocation Schemes

Table 7.1 below presents a brief summary of how the various issues described above affect some of the most prominent allocation schemes – the $SO_2$ allocation under the Acid Rain Program, the $NO_X$ allocation under the EPA SIP Rule, and a GPS.

**Table 7.1 Summary of Prominent Allowance Allocation Schemes**

| Design Issues | **Acid Rain – $SO_2$** | **EPA $NO_X$ SIP Rule** | **GPS** |
|---|---|---|---|
| Input/Output Basis | Input. | Input, with a proposal to move to output soon. | Output. |
| Permanent vs. Updating | Permanent. | Updating, after 5 years, then every 3 years. | Updating, every year. |
| Treatment of New Sources | No allowances provided. | Five percent set-aside for new sources. | Includes new sources, no set-asides necessary. |
| Treatment of Renewables and Efficiency | Efficiency and renewables et-aside was underutilized. | Recommends 5-15 percent set-aside for efficiency & renewables. | Efficiency and renewables can be included in the calculation of the target rate. |

## 7.4 New Source Review

NSR requirements serve an important function in preventing further air quality deterioration. However, NSR rules as currently applied place the burden of achieving this goal almost entirely on new plants. This not only creates potential for market power problems and barriers to entry, it also is economically inefficient and can undermine the goals of NSR.

The Clean Air Act includes some options for assisting new sources in obtaining offsets. For example, state and local governments have the option of applying more stringent regulations to existing sources in non-attainment areas, providing room for new sources within the state's implementation plan. However, few state regulators have chosen this option, probably because of resistance from existing sources.

There is no single recipe for the mitigation of distortions associated with NSR requirements. Rather, each solution must address the cause of the local problem. For example, where the pollution in a nonattainment area comes primarily from mobile sources (that do not often generate offsets), a new power project may have difficulty finding sufficient offsets. This situation may bestow market power on the existing power plants in the area. In this case, regulators may need to find innovative ways to help generate legitimate offsets from the mobile sector or other sources.

Some state air directors are developing programs that provide greater flexibility for new sources in obtaining offsets. For example the Northeast states' MOUs allowing interstate offset trading can significantly increase the availability of offsets. As another example, offset banks are being established to facilitate trading between sellers and buyers of offsets. Similarly, the EPA has noted that the NSR offset requirements could be met by integrating the offset trading system with the SIP $NO_X$ Budget Trading Program (EPA 10/1998). While there remains many complex issues to be addressed in integrating these two programs, this approach offers an important opportunity to mitigate the potential for market power and barrier to entry problems created by the NSR offset requirements.

Even if offset markets can be expanded, and offsets be made more easily available to new sources, NSR would still require significantly less stringent control technologies for existing plants than for new ones. Environmental regulators could revise NSR control technology requirements so that emission standards are applied equally to both existing and new sources. Comparable environmental standards could then be applied to all power plants, as described below.

## 7.5 Comparable Standards for All Power Plants

The most direct way to remove inconsistencies due to environmental regulations is to require all plants to meet the same emission standards – regardless of whether they are existing or new, and regardless of whether they are located in an attainment area or not. This could be achieved by combining some of the most appropriate policies and mechanisms described above, as follows:

- A GPS could be applied to all relevant power plants, both existing and new.

- Relevant power plants would include all fossil power plants and qualifying end-use efficiency and renewable resources
- The GPS would be a single output-based emission standard (in lb/MWh) applied to all affected resources, and would be updated annually to reflect actual generation and to include new sources as they enter service.
- All affected resources would be allocated allowances by multiplying their annual generation (or avoided generation) by the same emission standard.
- The GPS would be used to replace the current NSR provisions. The GPS emission standard would be set at a level designed to achieve the same environmental objective as the current NSR provisions – i.e., to prevent deterioration of air quality in both attainment and nonattainment areas. This would eliminate the different technology control requirements of NSR and would eliminate the NSR offset requirement.
- The GPS could also be used to achieve additional environmental goals. For example, the GPS could be used to achieve the goals of the EPA SIP Rule by developing an emission standard that is stringent enough to achieve the $NO_X$ budgets set by the EPA.

# 8. Conclusions and Recommendations

## Summary of Conclusions

We have assessed two types of distortions that might arise from inconsistent air quality regulations – inequities among competitors and market power problems. Inequities are likely to represent the majority of the distortions. Inequities will result from (a) NSR emission control standards that are as much as 25 to 50 times more stringent for new units than for existing ones, (b) NSR provisions that require new sources to purchase offsets from existing sources, (c) the Title IV allocation scheme that provides all $SO_2$ allowances to existing facilities, and (d) certain $NO_X$ allocation polices that provide insufficient set-asides for new sources, and do not account for the higher efficiency of new sources.

Market power is unlikely to be a problem in the $SO_2$ allowance market because the geographic boundaries of the trading system allows for many actors to participate. Similarly, the $NO_X$ allowance market is unlikely to suffer from market power problems – unless the geographic boundaries of the market are drawn too small. The greatest market power problem is likely to occur in the market for $NO_X$ offsets, because of tight geographic constraints and stringent regulation of existing sources. In some areas of the country (e.g., the Northeast) this risk is being reduced significantly through inter-state MOUs, while in other areas (e.g., Southern California) offsets represent a major market distortion.

Both types of distortions – inequities and market power – can create barriers to generation developers wishing to enter the competitive market. Barriers to entry are an important issue in the evolving electricity industry because timely and sufficient introduction of new competitors is absolutely essential to ensure the competitiveness of the market.

These barriers to entry may pose the most significant problems to developers of relatively small power plants, because of the economies of scale associated with emission control technologies. Economic and environmental regulators should be especially concerned about obstacles to small power plant developers, because some of them offer relatively efficient and clean power plants (e.g., cogeneration), and some could play an important role in the competitive electricity market as distributed generation resources.

It is difficult to quantify the magnitude of the market barriers created by inconsistent environmental regulations. The additional compliance costs imposed upon new sources by more stringent emission standards are difficult to identify because most of them are indirect, i.e., they are embedded in the construction and operating cost of the facilities. The expense of purchasing $NO_X$ offsets may not represent a large cost (in terms of $/MWh), but the availability of the offsets can become a problem to the extent that they are concentrated among a small number of owners of existing units. $SO_2$ and $NO_X$ allowances combined may provide existing coal units with an unfair benefit of roughly $3.5/MWh.

We find that divestitures and mergers are unlikely to create market power problems in the $SO_2$ or $NO_X$ allowance markets – unless the geographic boundaries of these markets are smaller than is currently anticipated. Divestitures and mergers might increase market power problems in offset markets, but only in those instances where there are relatively few entities able to generate offsets.

Nevertheless, in certain divestiture and merger contexts the market distortions created by inconsistent environmental regulations could be significant. This point is especially true given that barriers to entry can have an additive effect. One barrier might not be sufficient to hinder a new entrant, but when combined with additional barriers – due either to inconsistent environmental regulations or to other unrelated factors in the electricity industry – the combined affects could be enough to jeopardize a project.

## Recommendations to Economic Regulators

We recommend that economic regulators account for market distortions arising from environmental regulations whenever they assess the competitiveness of electricity markets. Such market distortions can reduce the competitiveness of the relevant electricity market, and might be enough to turn a sufficiently competitive market into one that is not.

For example, FERC's merger policy requires all merger applicants to conduct a market power analysis, including an assessment of market concentrations before and after the merger.[44] According to the FERC merger guidelines, if the concentration analysis indicates that a proposed merger may significantly increase concentration in any of the relevant markets, then FERC should consider other factors that could mitigate or exacerbate market power. Ease of entry into the market is one such factor (FERC 1996). Environmental regulations will clearly affect ease of entry, and thus must be considered in any such market power analysis.

There are many instances when economic regulators need to assess the competitiveness of electricity markets. Important examples include (a) reviewing merger and acquisition applications , (b) reviewing generation asset divestiture proposals, (c) investigating market-based rates, (d) debating whether to introduce retail competition, (e) reviewing proposals for Independent System Operators and Regional Transmission Organizations, and (f) developing "standard offer" mechanisms, "green power" programs, or other policies that depend upon competitive markets. Economic regulators may need to consider different industry structures or regulatory policies in light of the potential market distortions, or they may wish to consider various options to work with environmental regulators to mitigate some of those distortions.

The existence and extent of market distortions caused by inconsistent environmental regulations will vary significantly from one region of the country to another. When assessing the competitiveness of electricity markets in any particular region, federal and state economic regulators should routinely collect and analyze local and regional data

[44] Market concentration is measured by the Herfindahl-Hirschman Index (HHI), which is calculated as the sum of the squares of the market shares of all the competitors in a particular electricity market. Higher HHIs indicate higher levels of market concentration.

regarding emission allowance allocation schemes, control technology requirements, and offset requirements and markets. Particular attention should be given to emission offset requirements in non-attainment areas.

### Recommendations to Environmental Regulators

We also recommend that environmental regulators acknowledge the importance of competitive electricity markets when designing and modifying environmental regulations. As described in Section 3.2, if inconsistent environmental regulations delay or prohibit the introduction of new, more efficient, cleaner power plants, then the fundamental objectives of the environmental regulations will be jeopardized.

Section 7 of this report includes a brief summary of various options environmental regulators should consider for mitigating market distortions from environmental regulations. We recommend that environmental regulators develop comparable standards for all power plants. This can be achieved by designing a GPS to replace existing regulations, including the existing NSR provisions. All existing units and new sources would be required to achieve the same output-based emission rate. The emission rate would be determined in such as way as to achieve the desired environmental goals (e.g., the prevention of significant deterioration, the EPA $NO_X$ SIP Rule). Emission allowances would be allocated to all relevant electricity resources, including end-use efficiency and renewable resources, using the same output-based emission standard.

Short of this ideal solution, environmental regulators could take a variety of steps to correct the inconsistencies that exist in today's allowance allocation systems and NSR requirements. $SO_2$ and $NO_X$ allowance allocation schemes should be modified so that existing and new sources are treated equivalently. Renewable and end-use efficiency resources should be provided with allowances in a way that is equitable with the allocation to fossil units. Regulators should emphasize inclusive allocation schemes to ensure that all resources – existing, new, fossil, renewables and efficiency – are provided allowances on a consistent basis, and that there are sufficient allowances available for all relevant resource types.

With regard to NSR offset requirements, environmental regulators should seek opportunities to increase the number of actors that can generate and trade offsets. The MOUs being developed by the Northeastern states appear to be a good model for this. EPA's proposal to integrate the SIP $NO_X$ Budget Trading Program with the NSR offset requirements should also be pursue further.

Finally, environmental regulators should recognize that the EPA's proposed SIP Rule will be an important step towards more comparable environmental regulations, at least in the affected states. While this is not the primary motivating factor for the SIP Rule, it should be considered as an additional economic and environmental benefit.

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# Appendix A.
# $NO_X$ Control Options For Power Plants

Table A.1 presents a summary of the $NO_X$ control technologies for achieving $NO_X$ reductions in the electricity sector. All of the data in Table A.1 are taken from the EPA's study, *Analyzing Electric Power Generation Under the Clean Air Act* (EPA 3/1998) .

The majority of the $NO_X$ controls available are designed for coal plants. Some controls are applied in the combustion process itself, while others are applied after the fuel has been burned. On any one unit it is possible to apply both combustion and post-combustion controls. In such cases the removal rates are multiplicative.

The capital costs of the control technologies are levelized over thirty years using a fixed charge factor, in order to present total control costs in annual terms. We use a fixed charge factor of 10 percent, which assumes 25 percent debt financing at 7.5 percent, 75 percent equity financing at 15 percent, and includes federal income taxes, state income taxes, and local property taxes.[45] All costs presented in this study are in 1997 dollars. We do not account for increases or decreases in control costs beyond inflation.

It is important to note that in practice, the cost of these control measures, and the amount of $NO_X$ removal, might vary considerably from the costs presented in Table A.1. The cost will depend upon the unique characteristics of a unit's design, location, and operating patterns. For example, the costs of the few SCR technologies installed to date have varied significantly (Andover Technology Partners 1998).

Tables A.2 and A.3 present the control costs of typical existing coal units and new gas facilities, in terms of $/ton removed and $/MWh. For purposes of comparison, we assume that both units have a capacity of 400 MW and a capacity factor of 65 percent. The coal unit is a assumed to be a dry-bottom, wall-fired unit, with a heat rate and an emission rate equal to the average rates of all US dry-bottom, wall-fired units in 1996. The new gas units is assumed to be a combined-cycle, with a heat rate and emission rate taken from EPA 3/1998. Smaller units will incur higher costs, due to economies of scale. Units with lower capacity factors will incur higher costs, and those that operate more will incur higher costs.

Figure A.1 indicates the removal rates from some of the key $NO_X$ control options presented in Table A.1. It presents the $NO_X$ removal rates and control costs for a typical existing coal plant (dry-bottom, wall-fired) operating at 65 percent capacity factor, for different combinations of combustion and post-combustion controls. The greatest opportunity for removing $NO_X$ emissions can be found by combining low-$NO_X$ burners with SCR controls.

[45] Some power plant developers may use different recovery periods and use different financial assumptions, resulting in different annualized costs. These different assumptions can have a significant impact on the cost-effectiveness of projects. The control cost data in this appendix and in this report are presented for illustrative purposes only.

**Table A.1 $NO_X$ Control Technology Costs and Removal Rates for Fossil Units.**

| Technology | Applicable Boiler Type | Capital Cost ($/kW) | Capital Scaling[B] Base | Capital Scaling[B] Factor | Fixed O&M ($/kW-yr) | Variable O&M (mills/kWh) | Removal Rate[C] (percent) |
|---|---|---|---|---|---|---|---|
| **Coal Units: Post-Combustion Controls:** | | | | | | | |
| Selective Catalytic Reduction – Low $NO_X$ Rate | | 69.7 | 200 | 0.350 | 6.12 | 0.24 | 70.0 |
| Selective Catalytic Reduction – High $NO_X$ Rate | | 71.8 | 200 | 0.350 | 6.38 | 0.40 | 80.0 |
| Selective Non-Catalytic Reduction – Low $NO_X$ Rate | | 16.6 | 200 | 0.577 | 0.24 | 0.82 | 40.0 |
| Selective Non-Catalytic Reduction – High $NO_X$ Rate | Cyclone | 9.6 | 100 | 0.577 | 0.14 | 1.27 | 35.0 |
| Selective Non-Catalytic Reduction – High $NO_X$ Rate | | 19.0 | 100 | 0.681 | 0.29 | 0.88 | 35.0 |
| Gas Reburn - Low $NO_X$ Rate | | 32.4 | 200 | 0.350 | 0.49 | 0.00 | 40.0 |
| Gas Reburn - High $NO_X$ Rate | | 32.4 | 200 | 0.350 | 0.49 | 0.00 | 50.0 |
| **Coal Units: Combustion Controls:** | | | | | | | |
| Low $NO_X$ Burner Without Overfire Air | Dry Bottom Wall-Fired | 16.8 | 300 | 0.691 | 0.25 | 0.05 | 67.5 |
| Low $NO_X$ Burner With Overfire Air | Dry Bottom Wall-Fired | 22.8 | 300 | 0.691 | 0.35 | 0.07 | 67.5 |
| LNC 1 Close-Coupled Overfire Air[A] | Tangentially-Fired | 32.3 | 300 | 0.624 | 0.49 | 0.00 | 47.3 |
| LNC 2 Separated Overfire Air | Tangentially-Fired | 34.7 | 300 | 0.624 | 0.53 | 0.00 | 52.3 |
| LNC 3 Close-Coupled and Separated Overfire Air | Tangentially-Fired | 46.7 | 300 | 0.624 | 0.71 | 0.02 | 57.3 |
| Non Plug-In Controls | Cell Burners | 22.8 | 300 | 0.315 | 0.34 | 0.07 | 60.0 |
| Coal Reburning | Cyclone | 70.7 | 300 | 0.388 | 1.07 | 0.25 | 50.0 |
| $NO_X$ Combustion Controls | Wet Bottom | 9.6 | 300 | 0.553 | 0.14 | 0.05 | 50.0 |
| $NO_X$ Combustion Controls | Vertically Fired | 10.8 | 300 | 0.553 | 0.17 | 0.05 | 40.0 |
| **Oil & Gas Units: Post-Combustion** | | | | | | | |
| Gas Reburn – Combustion Control | | 19.8 | 200 | 0.557 | 0.30 | 0.03 | 50.0 |
| Selective Catalytic Reduction | | 28.1 | 200 | 0.350 | 0.87 | 0.10 | 80.0 |
| Selective Non-Catalytic Reduction | | 9.4 | 200 | 0.557 | 0.15 | 0.44 | 50.0 |

Source: EPA, March 1998, *Analyzing Electric Power Generation Under the CAAA*, Appendix No. 5. All costs are in 1997 dollars.

A. LNC 1, 2, and 3 all have low $NO_X$ coal-and-air nozzles.

B. The capital cost scaling factors represent economies of scale, where the cost/kW for a particular unit is equal to the base size divided by the actual unit size, with the scaling factor as the exponent. For example, for the SCR – Low $NO_X$ Rate at a 240 MW unit, the capital scaling factor cost would be 0.94, calculated as (200 MW/240 MW)^0.35 = 0.94. The size scaling factor for post-combustion controls reaches its limit at the capacity of 500 MW.

C. Each unit can have both post-combustion controls and combustion controls. The combined removal with the two types of $NO_X$ controls is multiplicative.

**Table A.2 $NO_X$ Removal Costs for a Typical Existing Coal Unit**

| | | | |
|---|---|---|---|
| **Fuel** | BIT | Bituminous | |
| **Boiler** | DB | Dry Bottom, Wall-fired | |
| **Capacity** | 400 | MW | |
| **Heat Rate** | 10,325 | Btu/kwh | 1996 average for uncontrolled units |
| **Capacity Factor** | 65% | | |
| **NOx Rate** | 0.70 | lbs/mmBtu | 1996 average for uncontrolled units |
| **Cap Rec Factor** | 10.0% | | |
| **Gas Reburn Adder** | 1.00 | $/mmBtu | Price difference between NG and Coal |
| **Annual Generation** | 2,278 | 1000 MWhr | |
| **Annual NOx** | 8,231 | tons | |

| **~~Technology~~** | **~~Type~~** | **~~Capital Cost~~** | **~~Fixed O&M~~** | **~~Variable O&M~~** | **~~Percent Gas Use~~** | **~~Removal %~~** | **Controlled Rate** | **Removed** (Tons) | **Removal Costs** ($/ton) | ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| LNB w/o OFA | CMB | 16.8 | 0.25 | 0.05 | 0.00 | 46.7 | 0.373 | 3,841 | 199 | 0.34 |
| LNB w OFA | CMB | 22.8 | 0.35 | 0.07 | 0.00 | 46.7 | 0.373 | 3,841 | 273 | 0.46 |
| SCR Low NOx | PCB | 69.7 | 6.12 | 0.24 | 0.00 | 70.0 | 0.210 | 5,761 | 899 | 2.28 |
| SCR High NOx | PCB | 71.8 | 6.38 | 0.40 | 0.00 | 80.0 | 0.140 | 6,585 | 868 | 2.51 |
| SNCR - Low NOx | PCB | 16.6 | 0.24 | 0.82 | 0.00 | 40.0 | 0.420 | 3,292 | 732 | 1.06 |
| SNCR - High NOx | PCB | 19.0 | 0.29 | 0.88 | 0.00 | 35.0 | 0.455 | 2,881 | 839 | 1.06 |
| NG Reburn - Low NOx | PCB | 32.4 | 0.49 | 0.00 | 16.00 | 40.0 | 0.420 | 3,292 | 1,511 | 2.18 |
| NG Reburn - High NOx | PCB | 32.4 | 0.49 | 0.00 | 16.00 | 50.0 | 0.350 | 4,115 | 1,209 | 2.18 |
| LNB + SCR High NOx | | | | | | 89.3 | 0.075 | 7,353 | 881 | 2.85 |
| LNB + SNCR High NOx | | | | | | 65.3 | 0.243 | 5,378 | 591 | 1.40 |
| LNB + NG Reburn High Nox | | | | | | 73.3 | 0.187 | 6,036 | 951 | 2.52 |

## Table A.3 $NO_X$ Removal Costs for a Typical New Gas Combined Cycle Unit

| | | |
|---|---|---|
| **Fuel** | Gas | Natural gas |
| **Boiler** | CC | Combined Cycle |
| **Capacity** | 400 | MW |
| **Heat Rate** | 6,773 | Btu/kwh |
| **Capacity Factor** | 65% | |
| **NOx Rate** | 0.15 | lbs/mmBtu |
| **Cap Rec Factor** | 10.0% | |
| **Gas Reburn Adder** | 0.00 | $/mmBtu |
| **Annual Generation** | 2,278 | 1000 MWhr |
| **Annual NOx** | 1,157 | tons |

| **~~Technology~~** | **~~Type~~** | **~~Capital Cost~~** | **~~Fixed O&M~~** | **~~Variable O&M~~** | **~~Percent Gas Use~~** | **~~Removal %~~** | **Controlled Rate** | **Removed** (Tons) | **Removal Costs** ($/ton) | ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas Reburn | PCB | 19.8 | 0.30 | 0.03 | 16.00 | 50.0 | 0.075 | 578 | 1,256 | 0.32 |
| SCR | PCB | 28.1 | 0.87 | 0.10 | 0.00 | 80.0 | 0.030 | 926 | 1,575 | 0.64 |
| SNCR | PCB | 9.4 | 0.15 | 0.44 | 0.00 | 50.0 | 0.075 | 578 | 2,278 | 0.58 |
| Low-NOX Comb. Controls | | 16.8 | 0.25 | 0.05 | 0.00 | 29.6 | 0.106 | 342 | 2,236 | 0.34 |
| LN Comb. + SCR | | | | | | 85.9 | 0.021 | 994 | 2,236 | 0.98 |
| LN Comb. + SNCR | | | | | | 64.8 | 0.053 | 750 | 2,778 | 0.91 |
| LN Comb. +NG Reburn | | | | | | 64.8 | 0.053 | 750 | 1,990 | 0.65 |

Low-NOX Combustion Controls assumed to have the same costs as LNB for coal plant. See OTAG 1996.

**Figure A-1 $NO_X$ Removal Rates and Costs for a Typical Existing Coal Unit.**