Grandfathering and Environmental Comparability:

An Economic Analysis of Air Emission Regulations and Electricity Market Distortions

Prepared for the
National Association of Regulatory Utility Commissioners

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June 11, 1998

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Acknowledgements

The authors wish to thank the many individuals who provided insight and comments on drafts of this report, including:

Steven Anderson, Harvard University
Tom Balon, MJ Bradley and Associates
Steve Brick, Clean Air Task Force
Max Duckworth, Tellus Institute
Howard Gruenspecht, US Department of Energy
Eric Hirst, Oak Ridge National Laboratory
Geoff Keith, MJ Bradley and Associates
John Kinsman, Edison Electric Institute
Donald Marron, University of Chicago
Brian McLean, US Environmental Protection Agency
Rick Morgan, US Environmental Protection Agency
Steve Nadel, American Council for an Energy-Efficient Economy
Richard Rosen, Tellus Institute
Nancy Seidman, Massachusetts Department of Environmental Protection
Jeffrey White, Attorney (commenting for EEI)

In addition, our project steering committee offered valuable guidance over the course of the project. These individuals include:

Brent Alderfer, Commissioner, Colorado Public Utilities Commission
Janet Gail Besser, Chair, Massachusetts Department of Telecommunications and Energy
James Gallegher, New York Department of Public Service Staff
Craig Glazer, Commissioner, Ohio Public Utilities Commission
Renz Jennings, Commissioner, Arizona Corporation Commission
Lucy Johnston, Massachusetts Department of Telecommunications and Energy Staff
Mary Kilmarx, Rhode Island Public Utilities Commission Staff
Theo MacGregor, Massachusetts Department of Telecommunications and Energy Staff
Karl McDermott, Commissioner, Illinois Commerce Commission
William Nugent, Commissioner, Maine Public Utilities Commission
Carl Peterson, Illinois Commerce Commission Staff
Ann Thompson, NARUC Staff
Rick Weston, Vermont Public Service Board Staff

As usual, the responsibility for any errors in this work resides with the authors.

1. Introduction And Executive Summary

Introduction

The Clean Air Act is widely recognized as an environmental success story. Compliance with the Act has, indeed, cleaned up our air. Under its influence, there have been noticeable declines in the emissions of key pollutants such as sulfur dioxide (SO_2) and nitrogen oxides (NO_X), both precursors of acid rain.

Yet there is a less widely recognized feature of the Clean Air Act that limits its success and biases its benefits. Older facilities -- those that were in existence when emission limits were adopted -- are held to much less stringent standards than newer ones. This practice, known as Agrandfathering≅ of the older facilities, has a substantial effect on the overall emissions of some pollutants. As we will show, most of the SO_2 and NO_X emissions from coal-fired power plants would be eliminated if all plants were held to the new-plant standards.

There are a multitude of related questions, which this report seeks to answer. Is there a theoretical rationale for grandfathering? What are its historical origins? How much of a distortion does it cause in the market for electricity? What would happen to existing coal plants if grandfathering of emissions standards were eliminated? Perhaps most important, what policy proposals could realistically allow a transition to an economy free of the distortions caused by grandfathering?

This report offers what we hope will be a thorough and thought-provoking review of the relevant literature, provisions of the Clean Air Act, and policy discussion surrounding grandfathering. It also presents quantitative estimates based on a unique database assembled for this project, combining generation, cost, and emissions data for individual coal-burning power plants. The more than 800 units in the database generated 1552 million MWh in 1996 -- 89 percent of the coal-fired generation, and 50 percent of all electricity generation by utilities in the U.S. that year. Thus our calculations rest on a plant-by-plant examination of virtually the entire industry.

Grandfathering And Economic Theory

The analysis begins in Chapter 2 with a look at grandfathering and economic theory. There is almost no support in economic theory for the practice of grandfathering existing facilities when adopting new regulations. Ideally, economics can tell us how to achieve efficient, least-cost implementation of a desired emissions standard; it provides little ground for permanently exempting older producers from standards that everyone else must follow. Indeed, economists have pointed out that grandfathering may give a hidden but powerful competitive advantage to the favored firms, undermining the efficiency of the marketplace. The best argument for grandfathering is that, when used as a temporary expedient, it may help build a consensus around a new regulatory standard. But, in order to limit the costs and disadvantages imposed on everyone else, grandfathering should be phased out as quickly as possible.

History Of The Clean Air Act And Grandfathering Provisions

The history of the Clean Air Act and its use of grandfathering is the subject of Chapter 3. Grandfathering of existing emissions sources has been a part of the Clean Air Act since at least 1970. Reasons given for grandfathering have included the belief that it is more cost-effective to insist on higher standards at new facilities when they are being built, coupled with the expectation that old plants would eventually retire and be replaced by newer ones meeting the higher standards. Participants in the original Congressional debates, and official reports from the 1970s and 1980s, make it clear that lower overall emissions were expected to result from the gradual phase-in of new plants and new energy technologies. Unfortunately, it turns out that many old plants are remaining in service far longer than expected, causing an indefinite delay in the anticipated emissions reduction from facility retirement.

Our summary of the provisions of the Clean Air Act relevant to grandfathering, in Chapter 4, begins with the warning that "it's not a simple story.≅ Through many layers of acronyms, technologies, and emission requirements, three aspects of grandfathering can be seen. First, in attainment areas, new facilities must at minimum meet the New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements, while existing facilities are generally subject to looser standards. Second, in non-attainment areas, new facilities must meet NSPS and New Source Review (NSR) requirements, while existing facilities are again subject to looser standards. Finally, under Title IV of the Clean Air Act, existing facilities receive free SO_2 allowances, roughly in proportion to past generation, while new facilities must buy them.

Economic Analysis Of The Grandfathering Effect

The coal plant database appears in Chapter 5. For both SO_2 and NO_X, average emission rates are positively correlated with plant age, just as expected. However, the correlation is far from perfect; there are wide variations in emission rates for each pollutant, even among plants of the same vintage. The handful of plants with the highest emission rates are not the same ones for the two pollutants. In terms of economics, we assume that the cost of a new gas plant represents the market price for electricity because the bulk of new power plant construction today consists of natural gas-burning facilities. Although gas plants are cheap, existing coal plants are cheaper: only 20 coal units, many of them very small, are currently more expensive than a new gas plant of comparable size and capacity factor.[1]

Using this database, it becomes possible to analyze the economic effects of grandfathering, in Chapter 6. What would happen if the industry as a whole had to meet the SO_2 and NO_X emissions standards for new sources? The answer to this question will tell us the magnitude of the distortion of the market caused by grandfathering.

To answer the question, we construct an environmental comparability scenario, assuming that SO_2 and NO_X emissions for the industry are set at the level that currently applies to

[1] Our economic comparison includes the capital costs required to construct new gas plants, but does not include the capital costs for existing coal plants because these latter costs are sunk.

new sources.[2] We do not require that each facility individually meet the standard; rather, we anticipate a trading mechanism, allowing emission reduction to occur in a least-cost manner, as with SO_2 allowance trading under Title IV. However, our analysis can be viewed as a worst-case outcome in several respects. We do not incorporate any of the likely measures that would be taken to improve the economic performance of troubled coal plants, such as renegotiation of coal contracts, reduction in O&M costs, or changes in capacity factors (even relatively small, expensive coal plants are often cheaper than new intermediate or peaking capacity).

With these qualifications in mind, we find that the environmental comparability scenario would have an upper bound annualized total cost of $9.2 billion, increasing the average cost of coal generation (including emissions allowances) from $21.1/MWh to $29.5/MWh. This is a 40 percent increase in the generation cost of coal-fired power, but only a 4 percent increase in the total retail cost of electricity in the U.S. These figures are subject to considerable uncertainty (discussed in Section 9 on further research). We consider the cost to be a high-side estimate, since it is primarily a "hardware" solution using current costs for the control technologies. In fact, we expect that a market approach to achieving the emissions reductions would tend to result in lower overall costs, in part because the large volume of control technologies installed would tend to encourage innovation and economies in the supply of controls.

With the additional abatement and control costs required under the environmental comparability scenario, 97 coal units, representing 6 percent of the total capacity in the database, would become uneconomic compared to new gas plants. As noted above, some of these 97 units could be saved by economy measures that we have not considered. More striking is the news about the other, generally larger, units: fully 94 percent of the coal capacity in our database would remain competitive with gas, even after paying the increased costs that are required to eliminate grandfathering of SO_2 and NO_X regulations.

In exchange for this cost, an immense reduction in emissions would be achieved. The environmental comparability scenario eliminates 75 percent of both the SO_2 and the NO_X emitted by the plants in our study under base case conditions -- 7.3 million tons of SO_2 and 3.3 million tons of NO_X. Coal plants are among the top sources of these pollutants; our calculated reductions are roughly 40 percent of U.S. total SO_2 emissions, and 15 percent of U.S. total NO_X emissions. The cost of reduction is, in very rough terms, about $900 per ton for each pollutant.

In summary, elimination of grandfathering could cost $9.2 billion per year, raise the average retail cost of electricity by 4 percent, achieve huge reductions in SO_2 and NO_X emissions, and allow at least 94 percent of existing coal capacity to remain competitive with gas.

The analysis is extended to other pollutants in Chapter 7. We find that meeting comparable environmental standards for other criteria pollutants (particulate matter,

[2] As discussed in Chapter 4, regulations applicable to new sources are dependent on both location and technology. In our environmental comparability scenario, we assume that all coal plants must meet a single standard: 3.0 lb/MMBtu for SO_2 and 1.5 lb/MMBtu for NO_X.

volatile organic compounds, carbon monoxide, and lead) imposes little or no costs on coal plants; the effects are several orders of magnitude smaller than for SO_2 and NO_X. This is mostly due to the fact that coal plants account for far smaller shares of total emissions of the other criteria pollutants.

The exception is carbon dioxide (CO_2), a ubiquitous result of fossil fuel combustion and a potent contributor to global climate change. Policy initiatives that address the threat of global climate change are all but certain to call for reductions in U.S. emissions of CO_2 -- roughly one-third of which come from electricity generation. Unfortunately, the environmental comparability scenario, introduced in Chapter 6 to abate SO_2 and NO_X emissions, does almost nothing to reduce CO_2 emissions. New gas plants emit about half the CO_2 per kWh of coal plants, so any CO_2 control or reduction strategy will favor a switch to gas.

To analyze a hypothetical example, the same apparatus that is used for the environmental comparability scenario is used again, adding to that scenario a $10/ton tax on CO_2 emissions (well within the range of policy proposals in environmental circles). In this case, if the other assumptions of our scenarios remain the same, then about one-third of all coal generation would become uneconomic relative to gas. However, since shifts of this magnitude will cause price effects and other industry responses (i.e., cost reduction measures), which we did not take into account, we suspect the actual effect would be significantly smaller.

Policies To Promote Environmental Comparability

We conclude, in Chapter 8, with an exploration of policies that could promote environmental comparability (i.e., the absence of grandfathering). Five major policy options are presented, and evaluated as to economic efficiency, political practicality, and effectiveness in removing the effects of grandfathering. The most conceptually straightforward option, applying the new source requirements to all plants, would be one of the most problematic. It offers neither the economic efficiency of the trading options (to which we turn next), nor any obvious political or administrative appeal.

Two related policy options offer two versions of emission trading processes. A cap and trade system, such as the one established for SO_2 allowances in the 1990 Clean Air Act Amendments, is economically efficient, currently quite politically popular, and can potentially be implemented on a state or regional basis where appropriate. Its potential problems include the risk of an inequitable initial allocation of allowances, and the difficulty of modifying the allocation of allowances or the cap on emissions once the system has been set up.

A variant on the trading mechanism, emission performance standards (EPS), offer many of the advantages of the cap and trade system, while perhaps avoiding some of the disadvantages. Under an EPS, an emissions cap is established, and divided by the total electricity generated to establish an allowable emissions standard (in lb/MWh). Companies with lower emissions generate credits, which can be sold to companies with higher emissions than the standard. In contrast to the cap and trade system, the EPS eliminates the problem of allocation of allowances, and makes it comparatively easy to modify the cap.

Two other policy options are likely of more limited value. Emission fees could in theory provide an appropriate response to pollution. However, in practice they face political opposition and administrative obstacles. Even if they were politically acceptable, fee structures designed specifically to compensate for or eliminate grandfathering would be particularly hard to administer, and might not be efficient, cost-minimizing policies. Finally, emissions disclosure, perhaps in concert with marketing of Agreen power,≅ may give consumers information that they would need to purchase cleaner sources of energy, thereby potentially offsetting the grandfathering effect. However, this is a very limited policy option for addressing the grandfathering effect, and is not strictly comparable to the other options discussed here. While emissions disclosure plays an important role in promoting green power, it is unreasonable to expect voluntary consumer action alone to achieve major policy changes such as overcoming the effects of grandfathering.

2. Grandfathering and Economic Theory

2.1 The Economic Critique

Economic theory offers little support for the inclusion of grandfather clauses in environmental regulations. The classic economic policy recommendation for environmental problems, the use of Pigouvian taxes to internalize externalities and reduce the incentives for pollution, makes no distinction between new and old sources of emissions. Newer policies favored by many economists, such as tradable allowances, are equally efficient with any initial distribution of pollution rights. Thus, for example, there is no obvious basis in economic theory for the intricate allocation of SO_2 allowances under the 1990 Clean Air Act Amendments, as opposed to alternatives such as annual government auction of all allowances (Ackerman and Moomaw 1997). The allocation of allowances in this case, or pollution rights in general, to existing facilities may be of great importance in winning political acceptance of new regulation -- more about this in a moment -- but such considerations should not be confused with economic theory.

An efficiency argument could be constructed in support of grandfather clauses; perhaps immediate application of new regulations would make it unprofitable to continue operating existing facilities. That is, regulations might be affordable for new plants, but so burdensome for old ones that it would be more attractive to shut down rather than comply. However, the analysis in Chapters 5 and 6 shows that this argument has almost no relevance to coal-fired electricity generation today.

On the few occasions where the question of grandfathering and environmental regulation arises in the recent economics literature, the conclusion is generally that grandfathering is not the optimal policy. Macroeconomic analysis of a standard growth model shows that command and control regulation, with grandfathering of existing emission sources, is inferior to an emissions tax on all (old and new) polluters. If the two options are designed to achieve equal levels of emission reduction, then the tax leads to better economic outcomes, provided that the pollution tax revenues are used to reduce income tax rates (Neilsen, Pedersen, and Sorensen 1995). Economists in the Alaw and economics≅ school maintain that command and control regulation, combined with grandfathering of existing sources, gives a competitive advantage to the industries, firms, and regions where the existing sources are located. This creates a powerful, hidden self-interest in support of such regulation (Maloney and McCormick 1982, Pashigian 1985, Bartel and Thomas 1987, among others).

One perverse effect of grandfathering is the incentive it creates to prolong the life of old equipment. The initial imposition of auto emission standards, making new cars more expensive, led many people to hold onto their older, more polluting cars for longer. Similarly, two studies have estimated the effect of environmental regulation on the rate of capital turnover in the electric utility industry (Nelson, Tietenberg, and Donihue 1993; Maloney and Brady 1988). Despite many differences in detail and outlook, the two studies= conclusions are quite similar: the regulations in place as of 1980 increased the average age of fossil fuel generating plants by 3-4 years.

2.2 Arguments for Grandfathering

In view of the economists= critique, what is the argument for grandfathering of existing pollution sources when new regulations are adopted? The principal response (aside from pure self-interest) is that imposing new rules on an existing facility seems unfair, as if the government is changing the rules during the game. This is an important but vague argument, which has proved surprisingly difficult to spell out in an unambiguous fashion.

The strongest claims compare the imposition of new regulations on existing facilities to seizure of property without compensation, which is of course constitutionally prohibited. Yet environmental regulation is only one of many government actions that can cause changes in the value of private properties. If all policy changes that reduce the value of existing property were classified as Atakings≅ that entitled the property owner to compensation, the result would be to offer property owners a guarantee that the effects of laws and regulations will never change -- an undemocratic and impractical outcome. The symmetrical policy of imposing windfall profits taxes to capture all increases in property values caused by government action is even less popular, but appears to be no more or less defensible than the strongest forms of the Atakings≅ argument (Kaplow 1986).

A more moderate version of the fairness argument might rest on John Rawls= concept of Aformal justice,≅ which requires security for legitimate expectations arising from existing legal institutions, regardless of the content of those expectations.[3] However, if this were made an absolute standard, it would suffer the same shortcomings as the Atakings≅ argument. In practice, formal justice is one of several potentially contradictory principles, which often must be weighed against each other. Legal scholars have examined the circumstances under which owners are compensated for state actions that diminish the value of their property. A classic analysis by Frank Michelman concluded that compensation usually is awarded for claims based on Asome distinctly perceived, sharply crystallized, investment-backed expectation,≅ as opposed to vague hopes and unexecuted plans.

2.3 Grandfathering and Policy Analysis

Grandfathering has received more extensive treatment in analyses of tax policy; the 1986 tax reform included special provisions and transitional assistance worth $10 billion to owners of assets whose taxes were raised by the act. Many of the issues raised in relation to tax policy are applicable to environmental policy as well. The economic critique can be heard here as well: Louis Kaplow has argued at length that compensation should almost never be paid for the effects of government policy changes (Kaplow 1986, 1992). In his view, the risks of future government action are no different from any other risks facing an investor. Sheltering investors from risks is directly at odds with the incentive effects that lead to efficient resource allocation. If the government establishes a consistent pattern of compensating investors for policy impacts, the expectation of such compensation will tend to undermine any incentive to anticipate the development of future policies. It is almost always more efficient, according to Kaplow, for an investor

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[3] The discussion of Rawls and Michelman in this paragraph is based on Goode 1987, which contains references to the original sources.

or business to buy private insurance against risk; the insurance premium will correctly internalize the risk, preserving the incentive for risk reduction.

Other analyses have resulted in more mixed evaluations. George Zodrow argues that grandfather rules can be politically desirable, converting potential losers from reform proposals into winners and thus building broader support for change (Zodrow 1992). However, he suggests that grandfather rules should be used with caution; in particular, the length of time they are in effect should be carefully limited. If a grandfathering provision remains on the books much longer than is needed to offset the affected property owners= potential losses, then the excessive exemption constitutes a loss to the rest of society, making the policy undesirable.

In a similar middle-of-the-road position, Richard Goode (1987) suggests ten criteria for judging when investors deserve grandfathering or other compensation for tax law changes. While some of his criteria are specific to tax policy, others are relevant to environmental issues, including the following (where the Abenefit≅ means the right to continue past levels of emissions):

- How specific are the expectations that an existing benefit will continue?
- Did the benefit originate as an intentional or accidental result of past policy?
- How controversial is the benefit? How much public discussion of change has occurred?
- How long ago did the investment occur? Was a change in policy under discussion at that time?
- How much has been invested, and how large would the losses on the investment be (both absolutely and relative to the investor's resources) if the policy change takes effect?
- How is ownership of the investments distributed by income and wealth? (That is, how rich are the people who will be paying the tax?)

2.4 Implications for Electric Utilities

In summary, the spectrum of opinion among economists, legal scholars, and tax analysts ranges from those who would virtually always oppose grandfathering as a needless distortion of market incentives, to those who see it as a politically necessary expedient that should be used selectively in a time-limited and cautious manner. No one, barring the most extreme advocates of the Atakings≅ argument, sees grandfathering as a generally attractive, long-term policy.

What does this imply for air pollution regulation and the electric power industry today? Regardless of one=s opinion on the theoretical debates about risk and market incentives, the argument for political expediency will remain important for the foreseeable future. It seems fitting, therefore, to consider the qualifications and criteria for appropriate use of grandfathering, remembering that it is an expedient compromise rather than a desirable policy on its own merits.

Goode=s criteria for judging grandfather rules may be a helpful starting point. Some of his criteria suggest the reasons why little or no grandfathering seems appropriate for electric utilities. The benefit of relatively lax environmental controls in the past was an accidental, not intentional, result of past policy, and there is no reason to expect it to continue; air pollution problems are certainly controversial, and public discussion of change in emissions standards has been extensive. Other criteria suggest reasons why grandfathering might win political support. Substantial sums have been invested in existing production technologies; some of the investments are quite old, and were made before any change in policy was under consideration. (However, the age of the investments has contradictory implications; see below.) The crucial question of the magnitude of the losses caused by environmental standards is addressed in Chapter 6.

Particularly relevant to the electric power industry is Zodrow's concern about limiting the time period for which grandfathering applies, and ending it as soon as possible after the affected investors have been made whole for the change in policy. For regulated utilities, this implies that grandfather clauses in environmental rules should never last beyond the period required for full recovery of the capital that was in the rate base when the rule was adopted. Any use of the facility beyond that time, or investment in plant life extension, should be viewed as a decision made after the new rule was in effect, and hence subject to that rule on the same basis as new facilities. The database used in Chapters 5 and 6 shows that one-third of all coal plants operating in 1996 were built before 1960, and more than half before 1970 (the share of old capacity is somewhat smaller, since newer plants are bigger). This suggests that many plants operating today have had ample time for recovery of the original capital investment – and therefore the strongest argument for grandfathering, the preservation of the conditions under which the original investments were made, may no longer apply.

3. History of the Clean Air Act

3.1 Legislative History

The Clean Air Act has evolved substantially over time. First enacted in 1963 and amended in 1965, it was essentially rewritten in its current form in 1970. Since then, amendments in 1977 and 1990 have modified many specific provisions, by creating new emission standards and emission control policies such as emissions trading, but the basic distinction made in the 1970 Act between existing and new sources has been maintained.

An existing source is defined as "any stationary source other than a new source" and a new source is defined as "any stationary source... which is commenced after the publication of regulations prescribing a standard of performance" (42 USCA 7411 (2) and (6)). Regulations to implement New Source Performance Standards (NSPS) were enacted in 1971 and were substantially revised in 1978. In the case of one of the most important pollutants, the later revisions shifted the requirements for controlling sulfur emissions heavily towards the use of flue gas desulfurization or scrubber technology for all new power plants. Hence, new power plants built after the revision in the rules were required to meet NSPS, but older plants were not. This differential regulatory standard permitted older power plants to emit two to six times as much sulfur dioxide as is allowed for new plants.

Several reasons for this bifurcation between existing and new sources of emissions have been given:

- Cost-effectiveness. "Congress concluded that it would be more cost-effective to require high levels of technological performance at new sources, because they have more flexibility as to location and design of control equipment than for existing sources" (U.S. Senate, 1970).
- Shift in political philosophy. Congress, "...reluctant to make a total break with New Deal models... remitted the problem [plants that existed in 1970] to a classical New Deal process in which the states were to play a leading role... [But i]n contrast, the act's treatment of new plants represented a sharper break with New Deal ideals... the act's approach to NSPS required all plants of the same type, regardless of their location, to meet the same emission ceiling" (Ackerman and Hassler, 1981).
- Eventual replacement of existing plants. "...The regulatory system established under the Clean Air Act... imposes more stringent emission limits on new sources than on existing sources... because existing sources will eventually be replaced by new ones, [resulting in] a gradual increase in emission reductions because new sources must use the more effective emissions controls. However, their bias against new sources also provides an incentive for firms to maintain their existing plant and equipment for a longer period than they might otherwise might have" (Hahn and Hester) .

It is this last reason which is at the heart of considerable controversy during the current deregulation debate.

3.2 Analysis of Clean Air Act Assumptions

It has proven surprisingly difficult to establish the original Congressional and EPA assumptions concerning the future evolution of a regulatory regime that had separate standards for existing and new sources of sulfur, nitrogen and particulate emissions. There is little in the legislation that speaks directly to this issue.

Thomas Jorling, Minority Counsel to the Public Works Committee that drafted the Clean Air Act, stated in interviews that the replacement of existing plants within normal operating lifetimes with newer ones that were subject to NSPS was implicit. David Hawkins, who was an influential attorney with the Natural Resources Defense Council who helped to shape the 1977 CAA Amendments agreed that it was assumed that older plants would eventually be replaced.

A 1975 EPA position paper on sulfate regulations, in a discussion of control alternatives, recognized that

> Ultimately, alternate energy supply systems (solar energy, thermonuclear fusion), improved combustion technologies (fluidized bed combustion), and general improvements in energy utilization efficiency should provide more effective use of energy resources with less environmental degradation (EPA 1975).

This study also projected that power plant emissions would peak in the early 1970's (when the peak addition of electric generating capacity occurred, and before NSPS requirements became mandatory) and would then decline and stabilize at a lower level into the 1990s.

However, the Congressional Budget Office (CBO) in 1982 projected that despite the provisions of the Clean Air Act NO_X and SO_2 emissions would begin to rise throughout the 1980s and 90s.

> After the turn of the next century, however, the prospects should brighten as antiquated generators are phased out and newer ones capable of emitting far less pollution take their place. Sometime around the year 2010, a trend in significantly lower emissions can reasonably be expected (CBO, 1982).

This is an explicit statement from an official Congressional source that not only anticipates the replacement of older, more polluting power plants by newer clean ones, but also anticipates when this will begin to occur for plants built in the 1960s. The report is even more specific about the anticipated lifetime of higher polluting plants.

> The long operating life of most electric plants -- usually 50 years -- suggest that most existing sources could be useful for emissions offsets and would continue to operate through the year 2010, after which a sharp drop in utility emissions could be expected because of the surviving generation of cleaner plants.

This statement is based upon the fact that the peak in "non-NSPS" facility construction occurred in the mid- 1970s. The study also recognized that the differential treatment of existing and new power plants created an economic disincentive to invest in new plants because “detrimental regulatory treatment of capital investments and advantageous fuel adjustment clauses discourage replacement of expensive oil and gas fired capacity and older coal burning facilities” (CBO, 1982).

More recent analysis also supports the expectation that older plants would eventually be phased out. However, as one commentator noted, it is an assumption

> which turned out to be false - namely... that air quality progress would be made if the Nation focused most of its pollution control effort on new sources, allowing old uncontrolled sources to live out their useful lives and retire, taking their pollution with them. This is the underlying logic of the stationary source requirements of the CAA... However the assumption of capital stock turnover - i.e. that old plants would be retired and replaced with new ones which would be cleaner and cleaner over time... turns out to have been a flawed assumption (Kete, 1992).

Apparently, no one anticipated that keeping a “pre-NSPS” facility operational would be so economically attractive that repowering and other techniques to extend the useful life of older facilities would become so widely used. This suggests that one might think of the life of a power plant as being defined in one of three different ways: 1) technological life, 2) economic depreciation life, and 3) regulatory life. Each one of these lifetimes contributes to the actual useful life of the power plant, but it is the latter whose significance has been most under-appreciated.

Our review of the history of the Clean Air Act strongly supports the position that the eventual replacement of existing power plants was implicit in the assumptions that lead to the less stringent emissions standard for existing plants. The issue facing regulators is how to address the abnormally extended "regulatory" lifetime of preexisting facilities. As the economics of the electricity industry shifts from that of a regulated monopoly to a competitive market, the cost distortions arising from regulatory preferences given to older plants will have significant implications both in the marketplace and in the environment.

4. The Grandfathering Effects Created By The Clean Air Act

4.1 Overview: It's Not a Simple Story

The theoretical and historical discussion up to this point may suggest a simple picture of the mechanism of grandfathering under the Clean Air Act: stringent requirements are imposed on new facilities, while older ones are unaffected. The reality of the Clean Air Act and its effects is staggeringly more complex than this. Existing plants are subject to various environmental restrictions under the Act, but these restrictions tend to be significantly less stringent than for new plants. In this chapter we identify and describe the critical difference in the requirements imposed on new plants relative to existing plants.

In order to explain the various grandfathering effects, two distinctions must be made: between Title I and Title IV of the Clean Air Act, and between attainment and non-attainment areas. Title I establishes national ambient air quality standards (NAAQS) for six criteria pollutants. Areas that persistently fail to meet these standards are called Anon-attainment≅ areas, and face tougher emission limits than "attainment" areas. Title I also contains the core description of standards that must be met by new facilities. Title IV, on the other hand, contains an innovative new policy adopted in 1990, notably the system of tradable SO_2 allowances. It also specifies new regulations for NO_X emissions. Both Title I and Title IV have implications for new and existing power plants.

This chapter presents the Title I and Title IV standards applicable to coal-burning power plants in some detail, focusing primarily on those regulations that will be in effect in the year 2000 and shortly thereafter. By far the most important regulations are those governing SO_2 and NO_X; regulations affecting other pollutants such as particulate matter may affect the industry in later years, but are not the principal focus of this report.

Amid the detail, there are three principal forms of grandfathering created by the Clean Air Act:

1. In attainment areas, Title I does not specifically regulate emissions from existing sources, but requires new sources to meet at least New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements.
2. In non-attainment areas, Title I requires some controls on emissions from existing sources, but imposes much stricter controls on new sources in the form of NSPS and New Source Review (NSR).
3. Under Phase II of Title IV (beginning in 2000), all SO_2 emitters must have allowances to match their emissions. Existing sources will receive free allowances equal to their past emissions times 1.2 lb/MMBtu, while new sources must buy all of their allowances.

The details substantiating this picture are presented in the following four sections. These sections address (1) Title I requirements, (2) Title IV requirements, (3) recent developments in implementing the Clean Air Act, and (4) a summary of regulations affecting new versus existing plants.

4.2 Title I Requirements

Title I establishes national ambient air quality standards that prescribe the maximum permissible concentration of pollutants allowed in the ambient air. Specifically, the Act requires the EPA to establish standards for six "criteria pollutants:" carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), ozone, and lead. Regions of the country where air pollution levels persistently exceed these standards are called "non-attainment" areas; other regions are called "attainment" areas.

In general, the responsibility for reducing air pollution levels has been assigned to the states. Each state is required to promulgate a State Implementation Plan (SIP) providing for the implementation, maintenance, and enforcement measures necessary to attain the ambient air standards by the deadlines prescribed by the Act. The EPA has the responsibility of reviewing each state's SIP, and is authorized to direct a state to revise its SIP if necessary (referred to as a SIP "call").

Impacts on New Sources

In non-attainment areas, in order to construct and operate a new power plant (or to make major modifications to an existing plant) the owner must obtain a permit from the state environmental agency (CAA Section 173). This New Source Review process requires the owner to analyze alternative locations, sizes, production processes, and control techniques, and to demonstrate that the benefits of the plant outweigh its environmental and social costs. The plants are also required to have control technology that meets the standard for lowest achievable emission rate (LAER).[4] The control technology required to meet LAER is established by each state on a case-by-case basis for each source of emissions as it is permitted.

Furthermore, the owner of the plant is required to purchase offsets for each criteria pollutant that is in nonattainment. The EPA requires that emission offsets provide a positive air quality benefit to the area, so owners are required to obtain more than one offset for each unit of pollutant emitted. The offset ratio depends upon the extent to which the region is in nonattainment. This offset requirement has promoted the establishment and trading of emission reduction credits for NO_X and volatile organic compounds (VOC) among industries in 12 states.[5]

The process for reviewing new facilities is slightly different in attainment areas (CAA Section 165). Owners are also required to obtain a permit to construct and operate new plants (or to make major modifications to existing plants), in order to ensure that new sources of pollution do not make the region slip into nonattainment. These Prevention of

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4 LAER is defined as that rate of emissions which reflects: (a) the most stringent emission limitation that is contained in the implementation plan of any State, or (b) the most stringent emission limitation that is achieved in practice , whichever is more stringent (CAA Section 171(3)(A)).

5 The states include CA, CT, IL, ME, MD, MA, MI, NH, NJ, NY, PA, TX, and VA (Cantor Fitzgerald 12/30/1997).

Significant Deterioration permits require a review of the air quality impacts of the plants. New plants are required to install best available control technology (BACT) for all pollutants regulated under the Act.[6] The control technology required to meet BACT is established by each state on a case-by-case basis for each source of emissions.

New power plants, regardless of whether they are located in attainment or nonattainment areas are also subject to New Source Performance Standards. The EPA has promulgated new source performance standards for SO_2, NO_X, and PM. New source performance standards are based on the level of control that can be achieved by the best demonstrated technology (BDT).[7] The first set of NSPS apply to fossil-fired power plants for which construction commenced after August 1971 (EPA 1974). The second, slightly more stringent set of NSPS apply to fossil-fired power plants for which construction commenced after September 1978 (EPA 1979).

In addition, the EPA is currently in the process of revising the NSPS for NO_X, because NO_X control technologies have improved since the current standards were set (EPA 7/1997). The EPA has proposed revising the NSPS to a more stringent emission rate based on the combination of low-NO_X burners (LNB) and selective catalytic reduction (SRC) technologies.

Impacts On Existing Sources[8]

In non-attainment areas, the requirements imposed upon existing sources will depend upon the SIP that is developed in each state. The Act requires that SIPs provide for the implementation of reasonably available control technology (RACT).[9] Each state has the responsibility to decide what technologies will be required in order to meet RACT. In addition, states may decide to require more stringent control technologies for existing plants if necessary to bring the state into attainment with NAAQS.

In attainment areas, Title I does not impose specific requirements for reducing emissions from existing sources. However, states can decide to impose emission reduction requirements on existing sources if such requirements are deemed appropriate in the context of the State Implementation Plan.

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6 BACT is defined as an emission limitation based on the maximum degree of reduction of the pollutant available through application of production processes and available methods, systems, and techniques, taking into account energy, environmental, and economic impacts and other costs (CAA Section 169(3)).

7 While BDT, BACT and LAER are defined slightly differently, the general underlying approach for all three standards is to require the "best control" option available (EPA 6/1997).

8 We use the term existing sources to refer to those power plants that have not been subject to New Source Performance Standards or New Source Review requirements.

9 RACT is defined as the lowest emission limitation that a particular source is capable of meeting by application of control technology that is reasonably available considering technological and economic feasibility (EPA 6/1997).

4.3 Title IV Requirements

Title IV of the CAA seeks to control acid rain by establishing restrictions on the emissions of SO_2 and NO_X from power plants. Title IV establishes an allowance cap and trade program for SO_2, with the goal of limiting nationwide annual SO_2 emissions from electric utilities to a cap of 8.9 million tons.[10] The act also seeks to reduce annual NO_X emissions by two million tons below 1980 levels, by requiring power plants to meet NO_X emission standards.

The provisions will be implemented in two phases. Phase I began in 1995 and applies to the utility power plants emitting the greatest amount of SO_2 and NO_X.[11] Phase II begins in 2000 and will affect most fossil-fueled producers of electricity, including virtually all utilities and some non-utilities.[12]

In Phase I all affected units are required to hold an allowance for each ton of SO_2 they emit, or incur a penalty. Affected units are allocated emission allowances based on the average amount of fuel burned (in BTUs) from 1985 through 1987, multiplied by an SO_2 emission rate of 2.5 lb/MMBtu. Title IV provides affected sources with the flexibility to either reduce emissions from their facilities, or to purchase emission allowances from other entities.

In Phase II power plant owners will be allocated allowances based on the average amount of fuel burned (in BTUs) from 1985 through 1987, multiplied by an SO_2 emission rate of 1.2 lb/MMBtu. Allowances will be allocated to existing facilities and to new facilities that began operation before 1995. New facilities that begin operation after 1995 will not be allocated any SO_2 allowances; they will be required to purchase all of their allowances (CAA Section 403). A total of 50,000 additional allowances (above the 8.9 million-ton cap) will be allocated to units in 10 states in the Midwest and South, in order to alleviate what was perceived to be a disproportionate burden on units in those states (CAA Section 405(a)(3)).

Coal-fired sources that are subject to the Phase I and Phase II SO_2 allowance program will also be required to meet emission standards for NO_X. The EPA promulgated NO_X emission standards that apply to two types of boilers during Phase I.[13] In December 1996

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10 This represents a reduction of roughly 10 million tons from 1980 emission levels.

11 Title IV explicitly specifies that 261 generating units at 110 generating plants located in 21 eastern and Midwestern states should be subject to Phase I requirements. In addition, utilities were allowed to use other units to substitute or compensate for those originally selected, and non-utility generation companies were allowed to opt-in to the program in order to obtain emission allowances. Thus a total of 445 units (referred to as affected sources) were subject to the program in 1995.

12 Most non-utility generators with power supply contracts in 1990 are permanently exempted from the provisions of Phase II.

13 These are referred to as Group I boilers and include dry bottom wall-fired boilers and tangentially-fired boilers.

EPA implemented a rule that sets the NO_X emission standards that will apply to virtually all boiler types during Phase II.[14]

During Phase I, Title IV imposes some SO_2 and NO_X requirements on existing power plants (i.e., affected sources) that are not imposed upon new plants. However, new power plants will be subject to NSR and PSD requirements under Title I that are all more stringent than those required of existing plants under Title IV.

During Phase II, Title IV generally imposes the same requirements for both new and existing plants. The one important exception is that existing sources will be allocated some SO_2 allowances but new sources (commencing operation after 1995) will not.

4.4 Recent Developments In Implementing The Clean Air Act

It is important to mention a few recent developments pertaining to the on-going implementation of the many provisions of the Clean Air Act. Each of the developments described below could impose greater restrictions on emissions from existing coal plants. They might therefore eventually reduce the gap in the environmental regulations that apply to new versus existing plants.

We have not incorporated the impacts of these developments in designing our economic analysis in Chapter 6. Given the difficulty in modeling a dynamic electricity industry with constantly evolving regulations, we have simplified our analysis by analyzing a snapshot in time. It should be noted that because of this simplification our economic analysis in Chapter 6 is likely to overstate the economic impacts of establishing comparable environmental regulations.

Ozone Transport Commission Memorandum of Understanding

In March 1992 the Ozone Transport Commission (OTC) adopted a Memorandum of Understanding (MOU) aimed at developing a regional program for reducing NO_X emissions in the Northeastern states. The OTC was established in the 1990 CAAA, and was motivated by the need to address regional transport of ozone in the region.[15]

The OTC MOU requires states to adopt regulations that require specific enforceable reductions in NO_X emissions relative to 1990 levels. The reductions are to be achieved in three phases. In Phase I the states commit to installing RACT on all major stationary sources of NO_X. In Phase II, to take effect May 1999, participating states will reduce their rate of NO_X emissions by 55 to 65 percent from 1990 levels, or emit NO_X at a rate no greater than 0.2 lb/MMBtu. In Phase III, to take effect May 2003, participating states would reduce their rate of NO_X emissions by 75 percent from 1990 levels, or emit NO_X at a rate no greater than 0.15 lb/MMBtu.

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[14] This new rule sets more stringent standards for Group I boilers than in the past, and establishes standards for all other boilers (Group II). Group II boilers include wet bottom wall-fired boilers, vertically-fired boilers, cyclones, boilers using cell-burner technology and other coal-fired boilers.

[15] The member states of the OTC include: CT, DE, DC, ME, MD, MA, NH, NJ, NY, PA, RI, VT, and VA.

New NAAQS For Ozone And PM

Under Title I, EPA is required to review periodically the National Ambient Air Quality Standards based on the latest science, and to update the standards if necessary to protect the public health and safety. In July 1997 the EPA revised the NAAQS for both ozone and PM, making them both more stringent (EPA 7/17/1997). With regard to particulate matter, the EPA established for the first time NAAQS for fine particulates, i.e., those particulates smaller than 2.5 microns in diameter (PM2.5).

Fossil-fueled power plants make significant contributions to ambient concentrations of ozone (through NO_X emissions) and particulate matter. In order to meet these standards, many fossil-fired power plants will eventually have to reduce emissions of NO_X and PM. The burden of meeting these standards will probably fall most heavily on existing plants, because they tend to have the highest emission rates.

However, the new ambient standards will not be applied for a number of years (EPA 7/17/1997). To meet the ozone standard, states have until 2003 to submit plans to the EPA detailing how it will be achieved, and then may have up to 12 years to actually achieve the standard. To meet the PM standard, states have until 2005 to 2008 to submit plans to the EPA, and then will have 12 years to achieve the standard.

EPA Section 110 SIP Call

The EPA is also undertaking a number of steps to assist states in meeting the current NAAQS for ozone. States within the Ozone Transport Assessment Group (OTAG), including the 37 easternmost states and the District of Columbia, have worked together and with the EPA to evaluate the problem of ozone that is transported between states.

In October 1997 the EPA found that the transport of ozone emitted from certain states within OTAG contributes to the nonattainment problems in other downwind states. Consequently, the EPA has issued a "SIP call" under Section 110 of the Clean Air Act, requiring certain upwind states to revise their SIPs and to maintain NO_X emission limits in order to mitigate the problem of transported ozone (EPA 11/1997). The SIP call proposes a specific NO_X emission budget for each of the 22 states (and the District of Columbia) that are assumed to contribute to the ozone transport problem.[16] The EPA also encourages the OTAG states to establish a NO_X cap and trade program for utilities, in order to reduce the costs of meeting the budgets.

The NO_X budgets are determined by assuming that fossil-fueled plants in each state meet emission levels that can be achieved with currently available, cost-effective control technologies. In determining the budgets, the EPA used a NO_X emission rate of 0.15 lb/MMBtu.[17] This is essentially the same emission rate that new power plants are required to achieve, in order to meet LAER as prescribed by New Source Review. This

[16] The states assigned a NO_X budget include: AL, CT, DE, DC, GA, IL, IN, KY, MD, MA, MI, MO, NJ, NY, NC, OH, PA, RI, SC, TN, VA, WV, WI (EPA 11/1997).

[17] The EPA SIP call establishes NO_X budgets for other sectors, in addition to electricity generators. The states are given the flexibility to allocate emission reductions across sectors as they see fit. Therefore, in practice some power plants may be required to meet budgets that are not equal the 0.15 lb/MMBtu rate.

is also the same emission rate that EPA used in its proposal to revise the NO_X NSPS. In general, a coal-fired power plant should be able to achieve this emission rate by utilizing SCR and LNB controls (EPA 7/1/1997). In effect, the EPA SIP call will require all coal-fired plants in some states to meet the same NO_X emission standards as new coal-fired plants.

However, the NO_X budgets are still in the proposal stage; there is still considerable debate about whether all affected states should be required to meet the budgets. In addition, there remain 28 states that are not subject to the proposed NO_X budgets. Furthermore, the SIP call NO_X budgets are based on seasonal emissions over the five summer months, and do not apply during the other months. Also, states will not be required to meet the proposed NO_X budgets for power generators until 2003 or later.

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 ozone ambient air quality standards. 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 (MA 1997). As of the time of writing this report the EPA had not acted on the petitions.

4.5 Summary Of The Difference Between Existing Versus New Plants

Given the many different layers of environmental regulations described above, it is useful for our purposes to identify the most stringent standards that apply to new power plants, for comparison with the most stringent standards that apply to existing plants. Here we briefly summarize those standards.

One caveat is in order. The state implementation plans containing the requirements for existing sources, and the NSR and PSD requirements of new sources, will be determined by regulatory agencies in each state. Therefore, the emission requirements may vary somewhat across the country. In theory RACT, BACT and LAER standards should not vary greatly from state to state because the control technologies available for power plants are quite transferable. However, in practice these standards can vary somewhat among states.

Sulfur Dioxide

As of 2000, essentially all existing power plants will be required to obtain one allowance for every ton of SO_2 emitted. However, they will be allocated allowances on the basis of historical fuel consumption multiplied by an emission rate of 1.2 lb/MMBtu. In other words, existing plants will be allowed to emit up to this rate for free, and will have to pay for any emissions above this rate.[18]

All new power plants will also be required to obtain one allowance for every ton of SO_2 emitted, but they will not be allocated any allowances at all. New power plants will also be required to meet the LAER standard under New Source Review, which essentially requires coal plants to utilize scrubber controls, with emission rates of roughly 0.3 lb/MMBtu.[19]

Therefore, existing plants are required to pay only for the cost of allowances for emissions that exceed the 1.2 lb/MMBtu rate. In contrast, new coal plants are required to pay for the cost of controlling emissions down to roughly 0.3 lb/MMBtu, as well as the cost of allowances for all remaining emissions. New gas plants emit very little SO_2, therefore the cost of allowances for these units will be minimal.

Nitrogen Oxides

As of 2000, essentially all existing power plants will be required to meet at least the Title IV NO_X emission standards. For the Group I boilers, which represent the large majority, the emission standards will be 0.46 lb/MMBtu for dry bottom wall-fired boilers, and 0.40 lb/MMBtu for tangentially-fired boilers. For the Group II boilers, the emission rates vary from 0.68 to 0.86 lb/MMBtu (EPA 7/7/1997).

New power plants will be required to meet the LAER standard under New Source Review and the BACT standard under the Prevention of Significant Deterioration requirements, both of which essentially require coal plants to utilize LNB and SCR controls, with emission rates of roughly 0.15 lb/MMBtu (EPA 11/1997; EPA 7/1997). This is approximately three times more stringent than the rate required of existing Group I boilers, and over four times more stringent than existing Group 2 boilers. New sources are also required to purchase offsets for NO_X emissions in nonattainment areas.

Other Pollutants

Title I of the Clean Air Act addresses four additional pollutants: carbon monoxide, particulate matter, lead, and VOC (as a precursor to ozone). Title I of the Act imposes many of the same requirements on these pollutants as for NO_X and SO_2. In nonattainment areas, state implementation plans should require existing emission sources to meet RACT standards, while new plants are required to meet New Source Review standards. In nonattainment areas, existing plants are not subject to specific

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[18] If the plants emit less than their allocated allowances, then the surplus allowances can be sold to others.

[19] Emission rates from coal plants with scrubbers can vary considerably depending upon the type of fuel used, the plant design, and the type of scrubber used. The EPA's RACT/BACT/LAER Clearinghouse indicates that recently-installed coal plants with scrubbers are expected to have emission rates ranging from 0.12 to 0.32 lb/MMBtu (EPA 12/1997). In a recent study, the EPA assumed that air pollution regulations for new coal plants would require annual emission rates ranging from 0.2 to 0.8 lb./MMBtu (EPA 7/1996).

requirements, while new plants are required to meet Prevention of Significant Deterioration emission standards.

However, fossil-fired power plants emit only small amounts of these pollutants, relative to other sources in the US. Consequently, power plants are not currently subject to a significant degree of regulation regarding these pollutants -- especially relative to SO_2 and NO_X. Therefore, the grandfathering effect regarding these pollutants is currently quite small -- if it exists at all. This issue is described in more detail in Chapter 7.

5. Current Power Plant Emissions and Costs

5.1 Overview of Current Plant Operating Economics

We begin our economic analysis of grandfathering by examining the most recent data available on costs and emissions of coal plants. We find that current levels of SO_2 and NO_X emissions are, on average, higher for older coal units than for newer units, but that there is a great deal of variation. Units of the same vintage can have emissions rates varying by a factor of ten.

We then proceed to examine the operating economics of the existing coal units. The total cost of new gas-fired generation, including the annualized cost of constructing the combined-cycle units, is taken as the market price that the existing coal units have to beat in order to remain competitive. We find that the vast majority of the existing coal fleet is competitive. The 20 units identified as “at risk” could possibly be shut down as a result of market forces, but more likely would cut costs or operate at lower capacity factors in order to remain viable.

The existing coal units are, on average, high emitters of SO_2 and NO_X compared with new technology, and are currently very economic on an operating basis. This context, detailed in this chapter, serves as the departure point for our analysis of the market distortions from grandfathering, presented in the following chapter.

5.2 The Coal Generation Database

For this project, we assembled a database on the existing coal generating units in the U.S. in 1996. This database includes information from (1) the Energy Information Administration of the Department of Energy, (2) the Environmental Protection Agency, and (3) the Utility Data Institute. The EIA data includes unit specific capacity ratings and vintage. The EPA data includes emissions of SO_2, NO_X, and CO_2 by stack. The UDI data includes fuel costs, operating costs, and electricity generation by plant. Together, the project database includes 886 coal units totaling 268 GW of capacity. In 1996 these units generated 1552 million MWh, amounting to a little more than one half of total electric utility industry generation.

5.3 Emission Rates of Existing Coal Units

The 1996 emissions from the coal units in our database amounted to 9.7 million tons of SO_2, 4.4 million tons of NO_X, and 1.6 billion tons of CO_2. The older units tend to have higher emission rates than the newer existing units, although the data show quite a wide variation. The scatter plot in Figure 5.1 shows the downward trend over time, as well as the variation. The three horizontal lines in the graph indicate the average emission rate for older units (those beginning operation before 1976), newer units (those beginning operation after 1975), and the 0.3 lb/MMBtu emission rate required by New Source Review. The newer coal units average about 0.7 lb/MMBtu of SO_2 with relatively little variation. While there are some older units at and below this level, the average for the pre-1976 vintage units is 1.7 lb/MMBtu, more than double the rate for the newer units. The SO_2 emission rates for older units also show a much greater degree of variation, with some plants emitting SO_2 at a rate ten times greater than the newer plants.

Figure 5.1 1996 SO_2 Emissions by Vintage

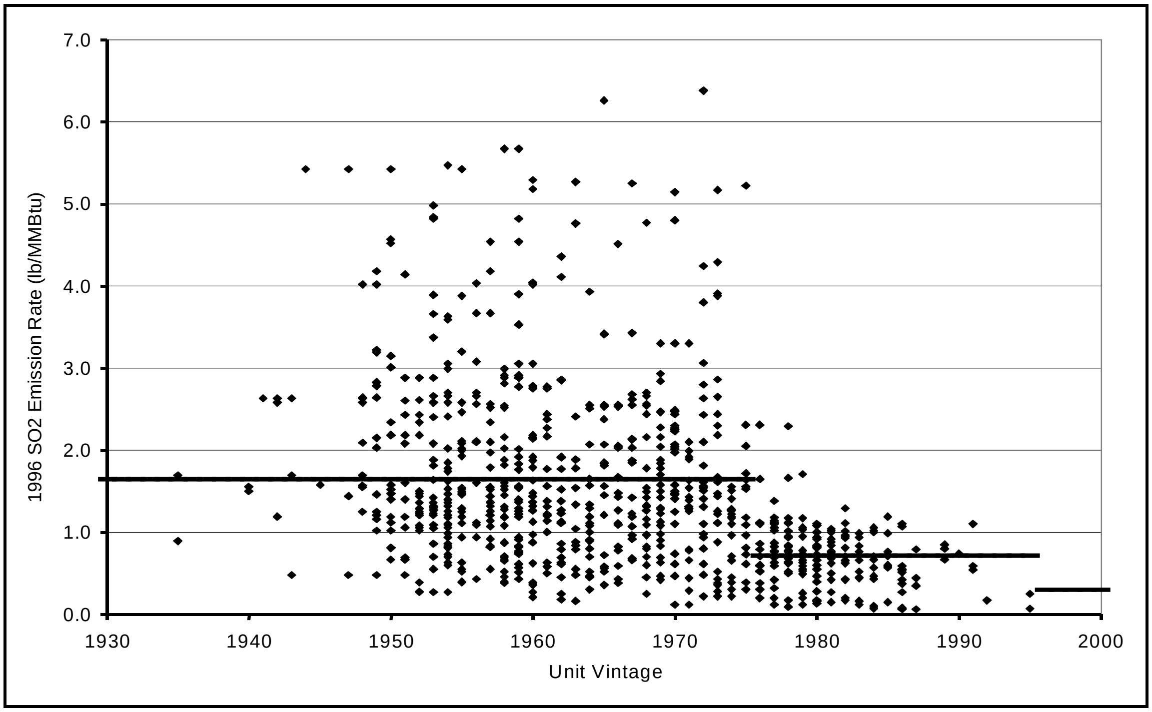
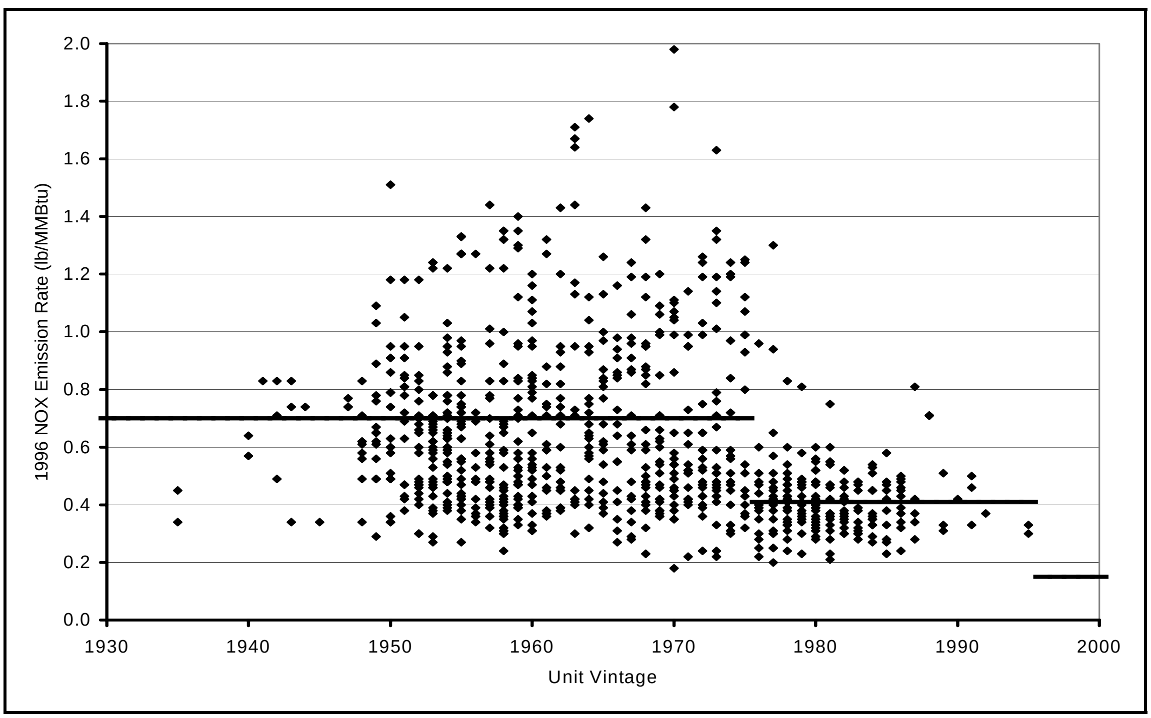


Figure 5.2 1996 NO_X Emissions by Vintage



For NO_X emissions, plotted in Figure 5.2, the pattern is similar to that for SO_2. Again, the three horizontal lines in the graph indicate the average emission rate for older units (those beginning operation before 1976), newer units (those beginning operation after

1975), and the 0.15 lb/MMBtu emission rate required by New Source Review. Post-1975 NO_X emissions for coal units in our database average about 0.4 lb/MMBtu, with older units averaging nearly twice this level, at 0.7 lb/MMBtu. Interestingly, while the patterns of pollution by age appear similar for SO_2 and NO_X, it is not the same units that are high emitters for both pollutants. Some of the high SO_2 emitting units are low NO_X emitters, and vice versa.

5.4 Regional Variations

Coal generation and emissions vary across regions of the U.S. More than one half of the coal units are located in two electricity regions: the East Central Area (ECAR) and the Southeastern Electric Reliability Council (SERC). The average coal unit operating costs are highest in the Northeast (NPCC). The average capacity factors are highest in the Texas (ERCOT), the West (WSCC), and the Southwest (SPP).

Table 5.1 Coal Unit Data by NERC Region

Region	Number of Units	Average Fuel and O&M Cost (cents/kWh)	Average Capacity Factor
East Central Area Reliability Council (ECAR)	263	2.0	55%
Electric Reliability Council of Texas (ERCOT)	21	1.7	74%
Mid-Atlantic Area Council (MAAC)	60	2.3	61%
Mid-America Interconnected Network (MAIN)	92	2.5	50%
Mid-Continent Area Power Pool (MAPP)	78	2.1	54%
Northeast Power Coordinating Council (NPCC)	35	2.8	62%
Southeastern Electric Reliability Council (SERC)	214	2.2	52%
Southwest Power Pool (SPP)	54	1.8	71%
Western Systems Coordinating Council (WSCC)	69	1.8	73%
Total	886	2.1	57%

5.5 Gas Combined Cycle Generation Sets the Market Price

Natural gas-fueled combustion turbine and combined cycle capacity are the options of choice for new electric generation requirements in every region of the country. About 85 percent of total capacity additions through the year 2020 are expected to be gas CT and CC units (EIA 1997, page 51). The simpler and cheaper to build CTs are the economical choice for peaking needs, while the more expensive and efficient CCs are the economical choice for intermediate and baseload generating needs.

The gas turbine technology has been improving over time to the point where new combined cycle generating efficiencies are projected to exceed 50 percent for advanced designs. With the costs of natural gas to utilities currently at $2.64 per MMBtu and expected to remain low for some time (EIA 1997) the cost of construction and operation can be as low as 3 cents/kWh for electricity. The cost per kWh, of course, depends upon the capacity factor at which the facility is operated. As shown in Table 5.2, for the cost and performance assumptions adopted here, the cost per kWh ranges from 3.1 cents/kWh at 90 percent capacity factor to 6.1 cents/kWh at 20 percent capacity factor.

Table 5.2 Cost and Performance Assumptions for New Gas CC Units

Inputs:		(all costs in 1996 dollars)
Parameter	Value	Comment
Capital Cost	$440/kW	Conventional technology (EIA 1997)
Heat Rate	7687 Btu/kWh	Projection for year 2000 (EIA 1997)
Fixed O&M	$15/kW-year	EIA 1997
Variable O&M	2.0 mills/kWh	EIA 1997
Capital Recovery Factor	12%	
Fuel Cost	$2.64/MMBtu	Average cost of natural gas to electric utilities in 1996 (EIA 1997)
Results:		
	Capacity Factor	Average Cost (cents/kWh)
	20%	6.1
	30%	4.8
	40%	4.2
	50%	3.8
	60%	3.5
	70%	3.3
	80%	3.2
	90%	3.1

5.6 Operating Economics: A Snapshot of Current Conditions

Before analyzing the impact of changes in environmental regulations to treat existing units comparably to new units, it is useful to examine the operating economics of the existing units under current conditions. Here we take a snapshot, in which the operating costs of existing coal units are compared with the construction and operating costs of new gas combined cycle generation.

Comparing the fleet of existing coal units to the cost of generation from new combined cycle gas units, we find that nearly all of the existing coal fleet is economic to operate. This is illustrated in Figure 5.3, below. The curved line represents the cost of gas combined cycle units are various capacity factors. All of the coal units fall below the gas combined cycle line, except for 20 units. These 20 units can be considered “at risk” and could possibly be shut down as a result of market forces. More likely, when faced with competition these units will either: (1) renegotiate their coal contracts, (2) cut their O&M expenses, or (3) operate at lower capacity factors.[20] We will discuss these possibilities later.

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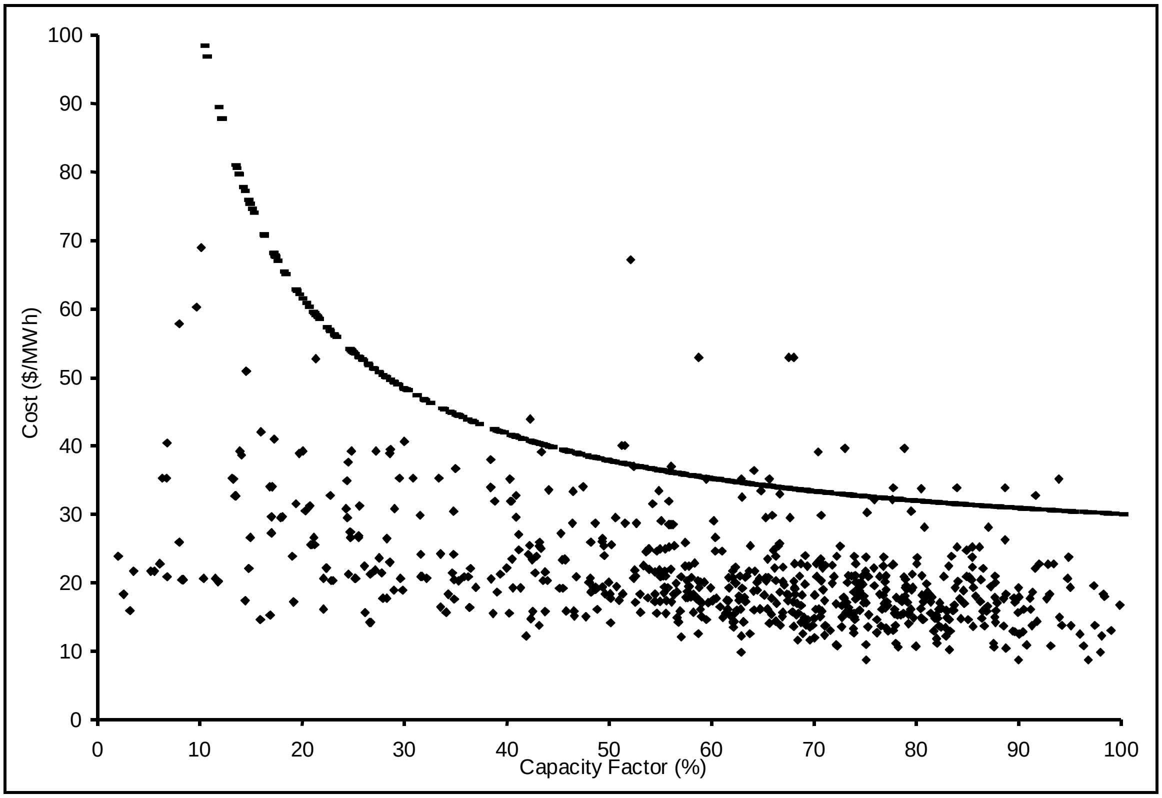
[20] It is also conceivable that some units, after a large investment in control technologies, might find their niches at higher capacity factors, where the benefit of their relatively clean production could be maximized, and the investment in controls can be amortized over more kWh generated. These changes in capacity factor (increases or decreases) are beyond the scope of the quantitative analysis conducted here.

Figure 5.3 Existing Coal Versus New Gas CC Costs; Current Conditions



To be clear, these results are for a current snapshot of the existing system, ignoring the costs of retrofitting the existing units to satisfy evolving environmental regulations. The results reported here are consistent with findings for the US power plant fleet using 1995 operating data (Biewald 1997) and with findings specifically for coal plants in the Midwest for the year 2000 forward (Bernow et al 1996).

6. Market Analysis of Comparable SO_2 and NO_X Regulations

6.1 Overview

As discussed in Chapter 4, new coal units in the US typically have to keep their emission rates at or below roughly 0.3 and 0.15 lb/MMBtu for SO_2 and NO_X, respectively. To provide emissions comparability, existing sources would have to be brought down to these levels. These emission rates are significantly below the emission rates currently produced by existing coal plants, as demonstrated by comparing them to the 1996 emission rates presented in Figures 5.1 and 5.2 above

Here we develop a scenario in which the SO_2 and NO_X emissions of existing coal units are controlled to these levels required of new units, and then we compare the resulting fleet of higher cost, lower emitting coal units with new gas combined cycle generation. In this case, a small but noticeable fraction of the existing coal generation (97 units, representing 6 percent of total capacity) is identified as being at risk. However, renegotiated coal contracts and other economizing measures might allow many of these units to remain competitive with gas.

6.2 The Environmental Comparability Scenario

The objective of this scenario was to determine the lowest-cost industry control strategy for achieving the emission target levels of 0.3 and 0.15 lb/MMBtu for SO_2 and NO_X, respectively. Our analysis assumed that there would be a market for SO_2 and NO_X emission allowances, thus not every unit would need to individually meet the target.

The basic approach is to determine the total emission reductions needed (i.e. tons of SO_2 and NO_X), calculate the control costs for the eligible units (based upon EPA data) and then implement them in economic order until the total goal is achieved. Slightly different approaches were used for SO_2 and NO_X control technologies.

We analyzed two control options for reducing SO_2 emissions: low sulfur coal and scrubbers. Switching to low sulfur coal is the cheapest solution for reducing emissions, but its availability is limited[21] and switching by itself can not generally reach target levels at individual units. Scrubbers are more expensive, but they are also more effective and can achieve new emission standards. For SO_2 control costs, low sulfur coal was applied first and then scrubbers were added to uncontrolled units in economic order ($/ton of SO_2) until the target was reached.

We analyzed two separate categories of controls for reducing NO_X emissions: combustion controls (e.g., low-NO_X burners) and post-combustion controls (e.g., selective catalytic reduction). A number of options might be possible for a given generating unit. However, combustion controls are always cheaper than post-combustion

[21] Additional low sulfur coal use was limited in this analysis to about 17 million tons per year, roughly 4% of current low sulfur coal use in the US.

controls so they were considered first. We want to achieve both the lowest average control cost and the required level of total reductions.

To achieve these goals we applied an iterative approach. A control cost level ($/ton) was selected, then the control technology combination was identified for each unit with the greatest total reduction whose cost was less than that cost level. The units were next processed in economic order and the total amount of reductions determined. If the total reduction goal was not achieved, the control cost level was incrementally increased and the process repeated. In essence, this was just walking up the control cost curve until the reduction target was achieved. In fact, for the vast majority of units, combustion and post-combustion controls were required in order to achieve the target emission rate for NO_X.

The emission control costs and removal rates are summarized in Table 6.1.

Table 6.1 NO_X and SO_2 Control Technology Costs and Removal Rates.

Technology	Applicable Boiler Type (A)	Capital Cost (B) ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M mills/kWh	Removal (C) %
NO_X Post-Combustion Controls:					
Selective Catalytic Reduction -- Low NO_X Rate		67	5.88	0.23	70
Selective Catalytic Reduction – High NO_X Rate		69	6.13	0.38	80
Selective Non-Catalytic Reduction -- Low NO_X Rate		16	0.23	0.79	40
NO_X Combustion Controls:					
Low NO_X Burner Without Overfire Air	DB	14	0.21	0.04	67
Low NO_X Burner With Overfire Air	DB	19	0.29	0.06	67
LNC 1 Close-Coupled Overfire Air (D)	T	27	0.41	0.00	47
LNC 2 Separated Overfire Air	T	29	0.44	0.00	52
LNC 3 Close-Coupled and Separated Overfire Air	T	39	0.59	0.02	57
NO_X Plug-In Controls	CB	19	0.28	0.06	60
Coal Reburning	C	59	0.89	0.21	50
NO_X Combustion Controls	WB	8	0.12	0.04	50
NO_X Combustion Controls	VF	9	0.14	0.04	40
SO_2 Controls:					
Scrubbers – Medium Sulfur (2% S)		172	6.2	1.0	95
Scrubbers – High Sulfur (3% S)		192	6.9	1.5	95
Scrubbers – Very High Sulfur (4% S)		202	7.3	2.1	95

Source: EPA, July 1996, *Analyzing Electric Power Generation Under the CAAA*, Appendix No. 5.

A. For boiler types, DB is dry-bottom wall-fired, T is tangentially-fired, CB is cell burners, C is cyclone, WB is wet bottom, and VF is vertically fired.

B. For scrubbers, capital cost scaling factors were applied, increasing the capital costs for installations smaller than 500 MW above those listed here.

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

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

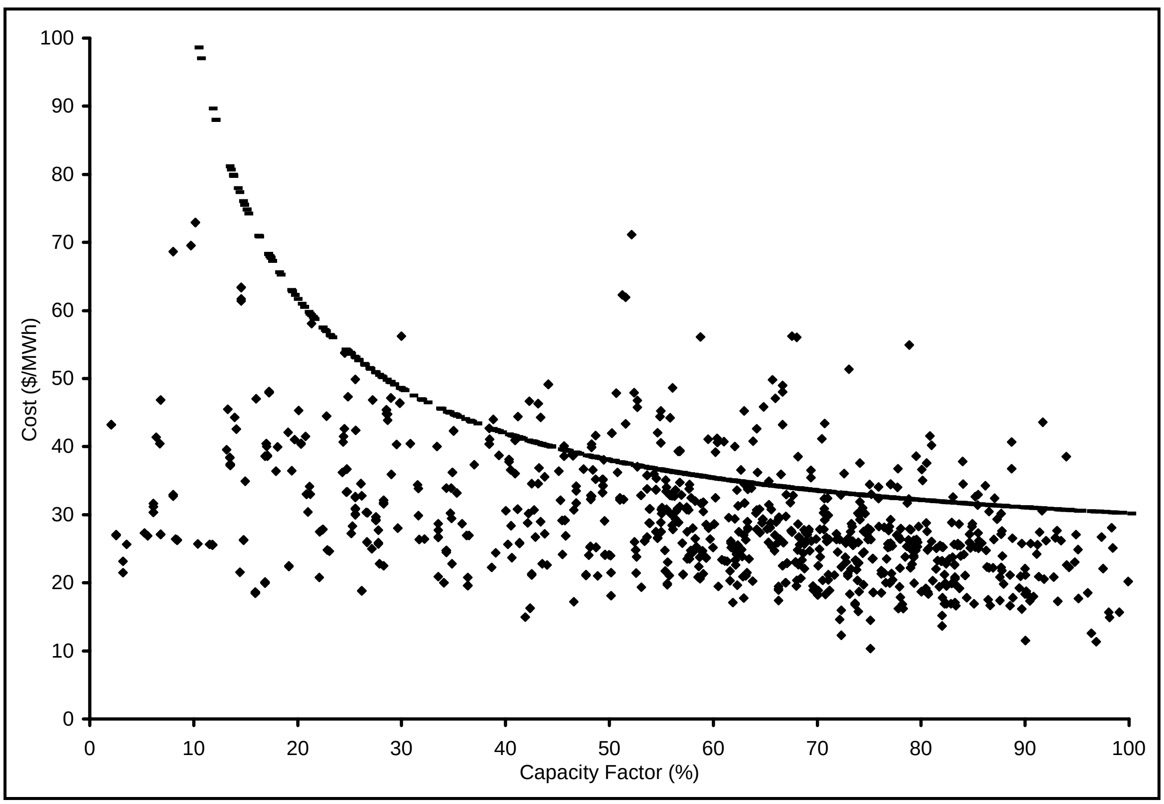
6.3 The Cleanup Cost and the Market Distortion

The resulting scenario has total annual SO_2 emissions from the coal units reduced by 7.3 million tons, and total annual NO_X emissions reduced by 3.3 million tons. For SO_2, the reduction represents 75 percent of the 1996 emissions from this group of coal plants, and roughly 40 percent of total US 1996 emissions from all sources. For NO_X, the reductions represent 75 percent of the 1996 emissions from this group of coal plants, and roughly 15 percent of the US total.

The average cost of coal generation (fuel, O&M, emissions controls, and emissions allowances) is increased from $21.1/MWh in the "current conditions" scenario to $29.5 in this emissions comparability scenario. The added cost of the emissions controls amounts to $9.6 billion on an annualized basis. Of this, $0.4 billion is for controls at units that might economically be retired and replaced with new capacity. The total anticipated cost of emission controls for the scenario amounts to $9.2 billion per year, of which about two-thirds is for SO_2 controls and one-third is for NO_X controls.

It is likely that this analysis overstates the costs of achieving the environmental comparability scenario for a variety of reasons. Market responses such as energy efficiency, fuel switching, changes in the dispatch, and improvements in the cost and performance of retrofit controls would all likely contribute to lower costs of achieving these emissions reductions than we have represented here.

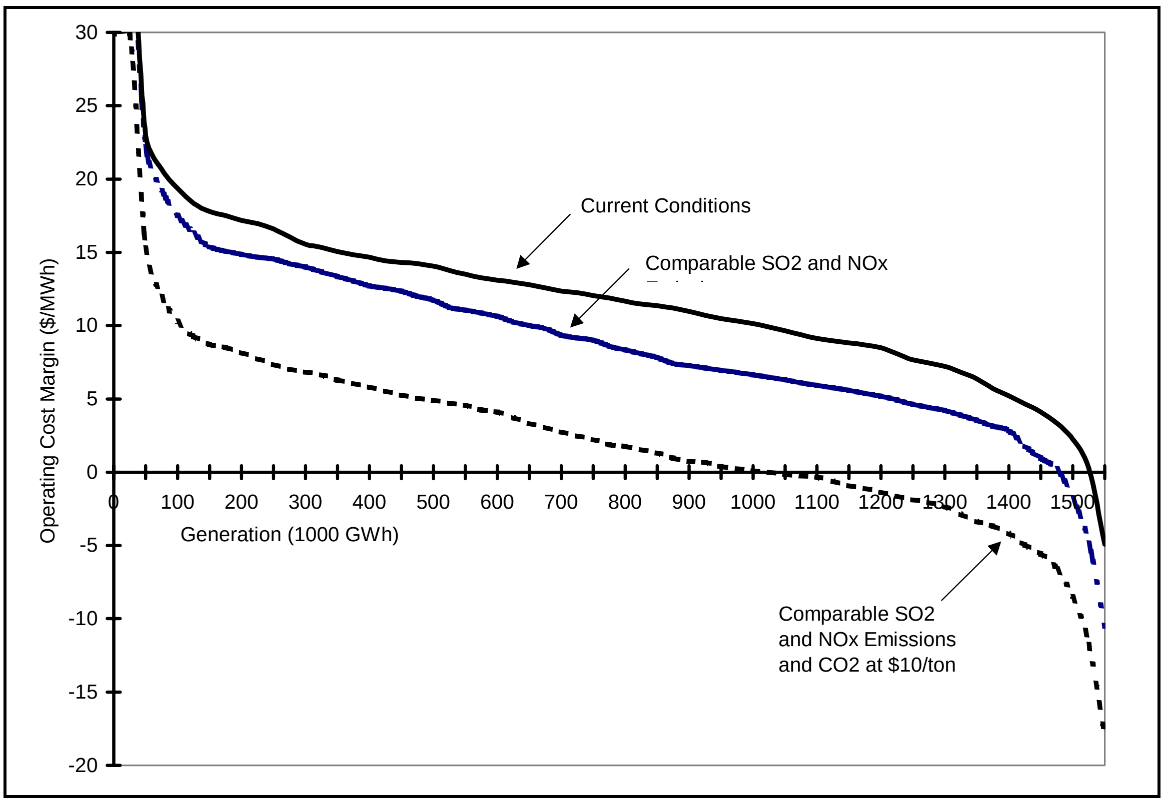
Figure 6.1 Existing Coal Versus New Gas CC Costs; Comparable SO_2 and NO_X Emissions



Nevertheless, even with this large amount of added cost, a remarkably large portion of the existing coal fleet remains competitive. Our analysis indicates that 97 units will be at risk in this scenario. These units produce only about 6 percent of total coal generation. They are about one-half the size, on average, of the units in the general population of coal plants.

Figure 6.1 (above) shows how the existing fleet of coal units is likely to fare under the environmental comparability scenario described above. This is the same group of coal units, plotted in much the same way as in Figure 5.3. Here, however, the cost of retrofit for SO_2 and NO_X emissions is included, as is the cost of purchasing allowances for any residual emissions. While some of the existing coal units are rendered uneconomic, or at risk of being so, the bulk of the fleet continues to operate economically. That is, the vast majority of existing coal units operates with the total of fuel and O&M costs low enough that even when the costs of emissions controls are added their forward going costs remain below the gas combined cycle generation cost that we use here as a proxy for the market.

Figure 6.2 Operating Margins for Existing Coal Generation; Three Scenarios for Environmental Regulation



In Figure 6.2, the vertical axis shows the operating margins for existing coal units, relative to the cost of owning and operating new gas generation. An operating cost margin of zero means that a coal plant costs exactly the same amount as a new gas plant; a positive margin means the coal plant is cheaper. The horizontal axis depicts the total amount of generation from the coal units. For both current conditions and for the scenario with added SO_2 and NO_X controls, it can be seen that most of the existing coal fleet is safely above the zero line. Generation in the positive region can be considered economic to operate on a going-forward basis.[22] (The third and lowest line on Figure 6.2 will be discussed in Chapter 7.)

The top two lines in Figure 6.2 are a way of summarizing the results depicted in Figures 5.3 and 6.1. Each coal unit on the economic side of the gas combined cycle generation cost shows up in Figure 6.2 as generation with a positive operating margin. Those coal units that fail the comparison with new gas generation costs appear to the right hand side of Figure 6.2, at a negative operating margin.

6.4 The Resilience of Coal

While new natural gas combined cycle generation is the technology of choice for new power plants there are many reasons why existing coal units are unlikely to be retired in large numbers as a result of competitive pressures. While the growth in coal use for electricity generation has slowed from the 6 percent average annual rate experienced during the 1960s and 1970s, it has continued to increase at an average annual rate of 2.5 percent over the last decade.[23] The EIA's reference case forecast has coal use for electricity generation growing at about one percent per year through 2020 (EIA 1998, page 102). The reasons to believe that this trend of increasing coal use is likely to continue include:

- the opportunity for at-risk coal generators to renegotiate above-market fuel supply contracts,
- the opportunity for at-risk coal generators to cut operating and maintenance expenditures, and
- the opportunity for at-risk coal generators to operate economically at decreased capacity factors.

It is only with the addition of environmental regulation of carbon that the trend in increased coal generation is likely to be stopped or reversed. The economics and market effects of carbon emissions regulation for electric generators is discussed in Chapter 7, below.

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[22] While economic on a forward basis, some of the generation may not be earning a large enough margin to cover its past investment (original construction cost and capital improvements already made). Since these investments are no longer avoidable (i.e., they are "sunk") they should not figure into decisions about future operation. Any embedded costs above market value of the assets could be stranded with the introduction of retail competition. For the most part, however, given the attractive operating margins identified here, we would anticipate that most of the coal fleet would have net positive value in the market, rather than contribute to stranded costs. It is not the purpose of this analysis to address the sunk investments in existing units. Nor is it our purpose to estimate stranded costs.

[23] Based upon consumption of coal data reported by the Edison Electric Institute, in various editions of the *Statistical Yearbook of the Electric Utility Industry*.

Renegotiation Of Coal Contracts

To some extent, the coal units identified as at risk in the scenario with aggressive SO_2 and NO_X caps are units with above average cost of fuel. To the extent that above-market coal costs are a factor toward rendering a unit uneconomic, it seems likely that the coal supplier would be willing to renegotiate the contract. While coal suppliers would prefer to sell at the highest possible price, if the choice is between putting the power plant out of business or making the sale at market price, most would prefer the latter.

Also, it should be noted that our economic analysis used actual costs of coal by plant for 1996. To some extent, the existing above-market coal contracts will expire naturally, and be replaced by new more attractively priced supplies. EIA projections have coal prices to electric utilities dropping steadily in real terms from $1.35/MMBtu in 1995 to $1.03/MMBtu in 2015 (both figures in 1996 dollars). This expected decline, at more than one percent real per year, is explained by "increasing productivity, a continued shift to lower-cost western production, and competitive pressures on labor costs" (EPA 12/1997, page 3).

One analysis of stranded costs looked specifically at the extent to which coal contracts are above market (RDI 1995). It found that the cost of above-market coal supply to US utilities over the period 1994 to 2000 amounted to $9.3 billion (in present value dollars). The opportunity to reduce these costs, not incorporated into our economic analysis presented above, would surely tip the market outcome somewhat toward continued operation of existing coal units.

Decreasing Coal Plant O&M Expenditures

As with fuel supply, there are considerable opportunities for existing power plants to cut their O&M costs. Indeed, average O&M costs at coal plants in the US have been rather flat in nominal dollar terms since the mid-1980s, and dropped by 7 percent between 1995 and 1996 (UDI 1997, page 19).

An analysis of opportunities for cost savings at existing power plants in one power pool found that potential for reducing operating costs was nearly 50 percent, on average (Bellucci et al 1996). While this may be overstated, the opportunities for cost reduction at existing units are clearly significant, and may be particularly large and compelling for the units that we have identified at risk. As we have not allowed for O&M reductions at the existing coal units, we have likely overstated the extent to which the existing coal units will be uneconomic to operate.

Decreasing Capacity Factors

The third possibility for coal units under competitive pressure is that they simply operate less. The simple average capacity factor for coal units in our database was 57 percent in 1996, with individual units spanning the full range from zero to 100 percent.[24] The 1996 average has room on the high side, for units to increase their capacity factors in the future. It also leaves room for individual units to decrease their capacity factors, particularly if they are at risk of closing. Translating the O&M cost for units in our

[24] The "simple" average is not weighted by size or generation.

database into a price per unit of capacity yields a figure of $20/kW-year.[25] This is much less than the annualized cost of new peaking capacity,[26] suggesting that these coal units can find a viable market niche, albeit at a reduced capacity factor.

The gradual decline in capacity factors of the existing coal units over time can be thought of as a natural technology cycle. That is, units originally constructed as baseload generators, over time shift toward operation in the intermediate and peaking range as new, more advanced technology is brought on line. This can be seen in the 1996 coal operating data, where older units tend to have lower capacity factors than newer units. In general, plants are phased toward decreased service gradually over time rather than retired in single decision to permanently deactivate the unit.

For electricity generation, the introduction of new efficient technology is overdue. The average efficiency of fossil fueled power plants in the US has been flat for decades. In 1961, the conversion efficiency of fossil fuels into electricity averaged 32.3 percent in the US (EEI 1982). In 1996 the average was improved, but only to 33.5 percent (EEI 1997). In between, during a period over which most of today's fossil power plants were constructed, the efficiencies have been extremely "stable." Over the same time period dramatic changes have taken place in the efficiencies of end use equipment and automobiles.

With new generating technologies available with conversion efficiencies approaching 50 percent, it would make sense from a technical perspective to replace the existing capital stock of coal plants. In contrast, our conclusion, based upon the economic analysis described in this report, is that for the most part the existing coal fleet will remain in operation, with new generating technologies coming online mainly to serve new loads. The new plants, once constructed, may operate at high capacity factors gradually displacing existing coal generation in the dispatch. This is, however, an incremental process that will take place only very gradually over time. It is not a massive shutdown of existing coal capacity based upon a failure of the existing fleet to meet the economic challenge from new technology on a head-to-head basis.

Remarkably, this conclusion would remain true even if all coal plants had to meet new source SO_2 and NO_X standards. That is, the elimination of grandfathering of these key pollutants under the CAA would make very few coal plants uneconomic. At most, there are 97 plants, representing 6 percent of capacity, that would be at risk; in fact, many of these plants would find ways to economize and remain in operation.

6.4 Regional Results

The results of our analysis are presented for each of the nine North American Electric Reliability Council regions in Table 6.2. The pattern of control costs roughly follows the distribution of coal capacity. The two regions that together have slightly more than one

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[25] $4 per MWh x 5 MWh/kW-year = $20/kW-year. In fact, roughly one half of the current O&M costs might be considered "variable," that is, avoidable by reducing output.

[26] A rough figure for the cost of new peaking capacity might be $300/kW construction cost, annualized at 12 percent, yielding $36/kW-year.

half of the US coal units also are found to incur slightly more than one half of the control costs in the comparability scenario. These regions are the East Central Area Reliability Council and the Southeastern Electric Reliability Council, which cover the states of Michigan, Indiana, Ohio, Kentucky, West Virginia, Virginia, Tennessee, North Carolina, South Carolina, Georgia, Alabama, and parts of other states.

Table 6.2 Results by NERC Region

Region	Annualized Control Cost (million $)	Increase to Cost of Coal Generation (cents/kWh)	Number of Coal Units At Risk (and % of region coal total)	Coal Capacity At Risk in MW (and % of region coal total)
East Central Area Reliability Council (ECAR)	2603	0.9	12 (5%)	721 (1%)
Electric Reliability Council of Texas (ERCOT)	306	0.6	0 (0%)	0 (0%)
Mid-Atlantic Area Council (MAAC)	778	1.0	22 (37%)	3289 (19%)
Mid-America Interconnected Network (MAIN)	967	0.9	18 (20%)	4425 (18%)
Mid-Continent Area Power Pool (MAPP)	578	0.7	4 (5%)	324 (2%)
Northeast Power Coordinating Council (NPCC)	298	1.1	22 (63%)	3588 (60%)
Southeastern Electric Reliability Council (SERC)	2522	0.9	11 (5%)	2323 (4%)
Southwest Power Pool (SPP)	951	0.8	2 (4%)	152 (1%)
Western Systems Coordinating Council (WSCC)	627	0.6	6 (9%)	740 (3%)
Total US	9630	0.8	97 (11%)	15563 (6%)

The increases in the average cost of coal generation associated with the emissions controls range from 0.6 cents/kWh in the Western Systems Coordinating Council and the Electric Reliability Council of Texas to 1.1 cents/kWh in the Northeast Power Coordinating Council. These figures include the additional costs of installing and operating the emission controls, as well as opportunity cost of the allowances to cover residual emissions.

These estimates are for the impact upon the cost of electric generation. In a market context, it is not entirely clear how changes in production cost will translate into changes in price to consumers. It may be that some of these costs cannot be passed along to consumers in a market environment. There is also the complexity created by the various overlapping and interrelated markets for electricity – increases in costs at a power plant located in one state could easily have impacts on electricity prices to consumers in other states.

Despite the concentration of coal use and identified control costs in the ECAR and SERC regions, only 23 of the 97 at-risk units are located in these two regions. The regions with the highest numbers of at risk units are the Northeast Power Coordinating Council, the Mid-Atlantic Area Council, and the Mid-America Interconnected Network, which together have 62 of the 97 at-risk units.

6.5 Sensitivity Analysis with Unit-Specific Data

As explained in Section 5.2, this analysis was conducted using data from EIA, EPA, and UDI. The analysis described above used capacity factor data (and most other data) on a unit-specific basis, but had operating costs per kWh on a plant basis from the UDI data (originally reported by utilities on their FERC Form 1 filings). The plant level cost data was used in order to avoid mixing data sources for this key input to the analysis.

The use of plant-level operating cost data does, however, naturally raise the question: would the use of unit-specific cost data result in major changes in the results? To test this, we conducted a sensitivity analysis in which unit specific heat rates (from EIA-860) and plant fuel costs per MMBtu (from UDI) were used to calculate unit-specific fuel costs per kWh. The results for this sensitivity case show slightly less capacity at risk (5% of total capacity at risk in this case compared with 6% in the base case), but are quite similar overall. Note also that the concern about unit vs. plant level cost data is an issue only for the calculation of the amount of capacity at-risk; the control cost calculations were done entirely using unit-specific data.

7. Environmental Comparability Issues Raised By Other Pollutants

7.1 Particulate Matter

As described in Chapter 4, Title I of the Clean Air Act establishes National Ambient Air Quality Standards for particulate matter. In 1995, there were 258 thousand tons of PM10 emissions from the electricity industry, which represented 10 percent of the total PM10 emissions in the US (excluding natural sources and fugitive dust). Of those electricity industry emissions, 96 percent were from coal-fired power plants (EPA 10/1996).

In general, new plants are required to achieve a more stringent emission rate for PM10 than existing plants. The current new source performance standards require new power plants to limit their PM10 emissions to 0.03 lb/MMBtu (EPA 1979). Currently, the average PM10 emission rate from all coal-fired power plants is about 0.043 lb/MMBtu, roughly 40 percent higher than the NSPS requirement (STAPPA & ALAPCO 1996).[27]

If all existing coal plants were required to meet PM10 requirements comparable to new power plants, they would have a variety of particulate control options to choose from. These options include: electrostatic precipitators, baghouses, different types of fabric filters, and coal cleaning and processing. Almost all existing coal plants already have some form of particulate control, mostly in the form of electrostatic precipitators. While many of these electrostatic precipitators do not control PM emissions down to the 0.03 lb/MMBtu level, they can be upgraded. In addition, baghouses can be used to augment electrostatic precipitators (STAPPA & ALAPCO 1996).

Table 7.1 Particulate Matter Control Options and Estimated Costs

PM Control Option	Control Costs (mill/kWh)	Control Costs ($/ton)
Electrostatic Precipitator	3.4	135
Baghouse (reverse gas)	4.0	162
Fabric Filter (pulse-jet)	3.4	138
Electrostatic Precipitator Upgrade	1.2	360
Baghouse on Existing Precipitator	1.9	not available
Coal Cleaning	not available	800

Source: STAPPA & ALAPCO 1996. Actual costs can vary significantly, depending upon the boiler, the technology used, and the type of coal used. Costs include levelized capital and operating costs.

The cost required for existing coal plants to meet a PM standard comparable to new power plants -- i.e., the 0.03 lb/MMBtu NSPS standard -- is likely to be significantly lower than those costs associated with NO_X or SO_2 standards. Table 7.1 presents some of these PM control options, along with estimates of their costs. In practice, power plant

[27] Maine, Massachusetts, New Mexico, and West Virginia limit existing coal-fired utility boiler particulate emissions to 0.05 lb/MMBtu, and Maryland limits these emissions to 0.04 lb/MMBtu (STAPPA & ALAPCO 1996).

owners could use a mix of these options, as well as lower-cost options such a unit repowering, unit retirement, alternative dispatching and energy efficiency.

We can get a rough indication of the costs required for all existing coal plants to meet the NSPS for PM10 by assuming a range of average control costs. If we assume that the average cost across all coal plants of controlling PM10 emissions to 0.03 lb/MMBtu is $100 per ton, then the total cost to the industry would be roughly $8.5 million, which would increase the price of all coal generation by roughly 0.005 mill/kWh.[28] If instead the average cost across all coal plants turns out to be roughly $400 per ton, then the total cost to the industry would be roughly $33.8 million per year, which would increase the price of coal generation by roughly 0.02 mill/kWh. These rough approximations suggest that the PM NSPS does not impose significantly higher costs on new plants relative to those that would be required of existing coal plants.

In addition to the "primary" particulate emissions described above, the SO_2 and NO_X emissions from power plants include particulates as well -- referred to as "secondary" particulates. For every ton of gaseous SO_2 emission, roughly ten percent is secondary particulate matter. For every ton of gaseous NO_X emissions, roughly five percent is secondary particulate matter (STAPPA & ALAPCO 1996). The control technologies used on new plants to capture SO_2 and NO_X (e.g., scrubbers and SCR) tend to also capture a large portion of the secondary particulates.

When existing power plants are allowed to emit higher SO_2 and NO_X emissions than new plants, they are also in effect being allowed to emit higher levels of secondary particulates. Hence, the grandfathering effect of the SO_2 and NO_X regulations leads to greater secondary particulate emissions from existing power plants. However, this does not impose additional costs on new plants, because the technologies used by new plants to capture the secondary particulates are required for SO_2 and NO_X control anyway.

7.2 Volatile Organic Compounds

Title I of the Clean Air Act also establishes National Ambient Air Quality Standards for ground-level ozone. Volatile organic compounds, along with NO_X and CO, are a precursor to ground-level ozone formation. Reduction of VOC emissions, therefore, is one option for meeting the ozone NAAQS.

However, power plants tend to emit significantly lower levels of VOC than NO_X. In 1995, VOC emissions from the electricity industry represented roughly 0.2 percent of total VOC emissions in the US (EPA 10/1996). Of those VOC emissions in the electricity industry, 83 percent came from coal-fired power plants.

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[28] Moving the industry average PM10 emission rate down to 0.03 lb/MMBtu would represent a 30 percent reduction from the current average of 0.043 lb/MMBtu, which would require a reduction from 1995 emissions of 84,600 tons, costing $8.46 million. The $8.46 million would be spread over 1,653 million MWh of coal generation in 1995, for an average cost of 0.005 mill/kWh. This average estimate assumes that power plants that do not meet the 0.03 lb/MMBtu standard would be able to purchase PM allowances from those that exceed it.

Some ozone nonattainment states require owners of new power plants to purchase offsets for VOC emissions, if the increase of VOCs from the new plant is considered significant. Eleven states have established VOC "emission reduction credit" (ERC) trading systems to allow for buying and selling of VOC reductions.[29] The price of the VOC credits varies across states, and depends upon the severity of nonattainment and the time of year. Currently, the price of VOC credits tends to range from roughly $1,400 to $3,700 per ton (Cantor Fitzgerald 12/31/1997).

Purchasing VOC offsets represents a cost imposed on new power plants that is not imposed upon existing facilities. However, the amount of the cost difference is quite small due to the low levels of VOC emissions from coal plants. We do not consider VOC emissions to represent a significant grandfathering issue.

7.3 Carbon Monoxide and Lead

Title I of the Clean Air Act also establishes National Ambient Air Quality Standards for carbon monoxide and lead. Power plants do not emit high levels of CO or lead, relative to other criteria pollutants. In 1995, CO and lead emissions from the electricity industry represented less than 0.4 and one percent of the total CO and lead emissions in the US (EPA 10/1996).

Consequently, the electricity industry has not been a target for reductions of CO or lead emissions. In addition, there are many fewer regions of the country that are in nonattainment for CO and lead, relative to ozone or particulate matter nonattainment.[30]

We are not aware of any CO or lead emission requirements that have been imposed on existing power plants. While New Source Review technically requires owners of new power plants to purchase offsets for all criteria pollutant emissions, we are not aware of any states that have imposed this requirement for CO or lead emissions. Therefore, it appears as though there is not currently any environmental grandfathering effect on these two pollutants.

7.4 Carbon Dioxide

Climate Change Policy And CO_2 Regulation

The connection of grandfathering to climate change is a complex one. Carbon emissions are not currently regulated, but it is becoming increasingly likely that they will be in the not-too-distant future. The Kyoto protocol to the United Nations Framework Convention On Climate Change, agreed to in December 1997, requires all signatory nations to reduce their CO_2 emissions by 2008-2012. Under the protocol, the US is obliged to reduce its CO_2 emissions to seven percent below 1990 levels. The protocol also proposes an international CO_2 credit trading system to help achieve this goal. The Clinton

[29] To date the following 11 states have established VOC trading systems: CA, CT, IL, MD, MA, NH, NJ, NY, PA, TX, and VA (Cantor Fitzgerald 12/30/1997).

[30] As of October 1997, there were 28 areas in nonattainment for CO and 10 areas in nonattainment for lead, compared with 59 areas in nonattainment for ozone (EPA 10/1997).

Administration's current plan calls for a phased approach on CO_2 with a cap and trade system to begin in 2008.

While there is still some debate about whether the US Congress will ratify the Kyoto protocol, it is becoming increasingly likely that some form of CO_2 regulation will be required soon. Even achieving a more modest goal than that proposed at Kyoto would require immediate actions to reduce CO_2 emissions. Given that the electricity sector is responsible for roughly one-third of US CO_2 emissions, it will have to play a significant role in meeting any CO_2 reduction target.

The Limited Carbon Reduction Benefit Of SO_2 And NO_X Regulations

From the perspective of climate policy, it would be convenient if the regulation of other pollutants (e.g., SO_2 and NO_X) would produce a windfall benefit in the form of CO_2 emissions reduction. However, the results presented in Chapter 6 do not support the prospect of an unintended CO_2 reduction benefit. The vast majority of existing coal units are likely to continue in operation emitting CO_2, even in the scenario in which aggressive reductions (75 percent from current levels) in SO_2 and NO_X emissions are required of the existing coal fleet.

If this scenario were to unfold over time, we could expect increases in CO_2, as the existing generators remain in service primarily serving existing loads, and new generators are brought online primarily to serve new loads. The new gas combined cycle generators have CO_2 emission rates at about one half the rate per kWh of existing coal, but they do emit CO_2. As the electric power system grows, CO_2 emissions can be expected to grow as well, in the absence of specific policy to the contrary. As one example, EIA's latest reference case projection has CO_2 emissions from electric generators in the US growing by 1.5 percent annually through the year 2020.

The Potential Impact Of Carbon Policy

Rather than hope for reductions in CO_2 emissions from indirect policy initiatives, we might implement policy directly aimed at reducing CO_2 emissions. With a direct policy such as a carbon tax or carbon cap and trade system we would see dramatic reductions in CO_2 emissions. This can be seen in the scatter plot of Figure 7.1 (below).

In this case, with CO_2 priced at $10/ton,[31] we see that many of the existing coal units are now at risk. The third line in Figure 6.2, in Chapter 6 above, shows that coal units producing approximately one third of the total coal generation would be at risk in this scenario. Although a shutdown of one-third of total coal capacity is hard to imagine, it seems reasonable that an active CO_2 abatement policy would lead to significant coal plant retirements.

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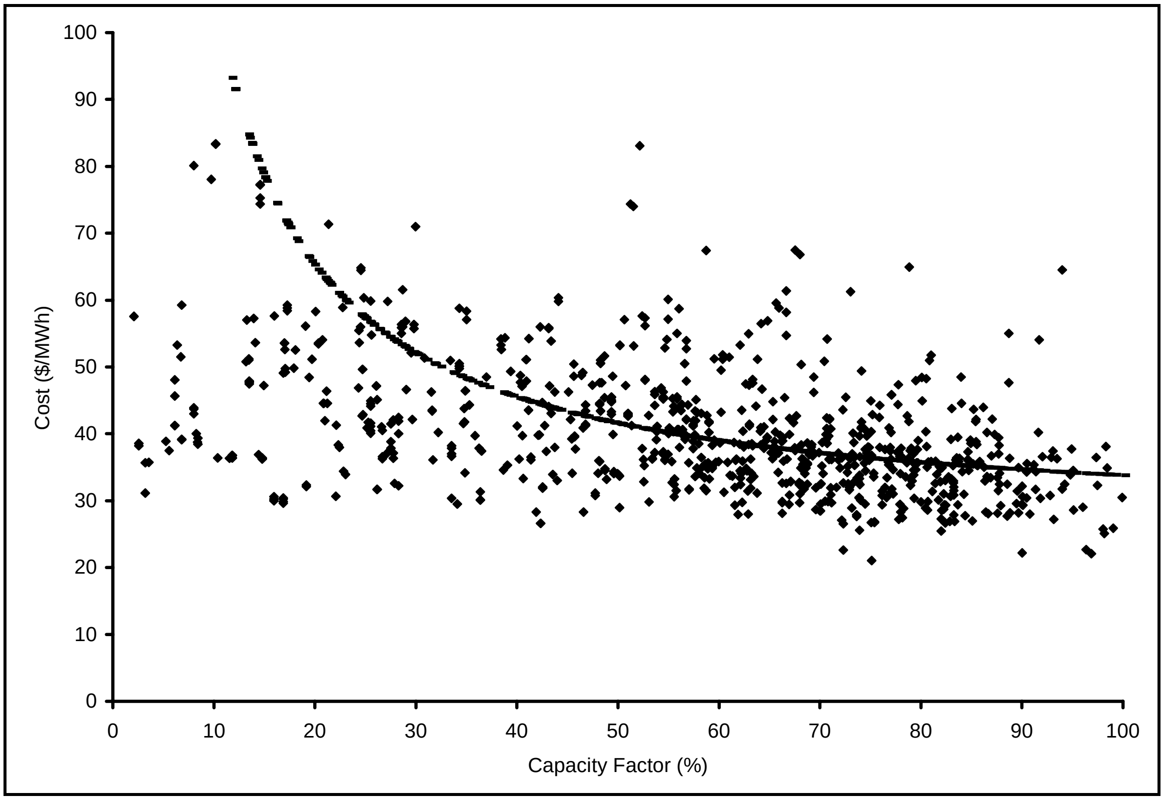
[31] The $10/ton figure could be a CO_2 tax set at that level, or it could represent the trading price for CO_2 allowances under a cap and trade system. Either way, the operating economics would look the same on a forward, opportunity cost basis. We pick the $10/ton figure here simply to illustrate the possible impact of CO_2 policy – the actual trading price will depend upon where the cap is set, as well as many details of the policy design and the market response.

Figure 7.1 Existing Coal Versus New Gas CC Costs; Comparable SO_2 and NO_X Emissions, And CO_2 at $10/ton



Of course, the same considerations discussed earlier that work to maintain a role for coal in the generation mix would be in effect. That is, the amount of coal unit retirement under a $10/ton CO_2 scenario would likely be much lower than is estimated here. Moreover, this scenario represents such a large departure from current conditions that the framework used in this study cannot be entirely trusted. For large excursions from existing conditions it is important to use a model that can recognize in some way the feedbacks in the system. For example, as coal units are shut down and additional gas generation comes on line to replace it, price effects can be expected. Coal prices would tend to decrease while gas prices would tend to increase. Analysis of the effect of changes to supply and demand upon prices in fuel markets is important, but beyond the scope of our present study. [32]

The Importance Of Coordinated Abatement Strategies

While the present study is mainly concerned with environmental comparability, and thus policies to reduce emissions other than CO_2, a note on coordinated abatement is appropriate. We have seen in the analysis presented in Chapter 6 that policy for environmental comparability in SO_2 and NO_X emissions could lead to a large investment in emission control technologies such as low NO_X burners, selective catalytic reduction,

[32] That is, the price feedback is important to account for in scenarios in which large deviations from the current resource mix are anticipated. Where the resource mix changes are small the fuel prices can reasonably be assumed to be fixed across scenarios.

and flue gas desulfurization. The annualized cost totaled about $9 billion for the scenario to meet targets of 0.3 lb/MWh and 0.15 lb/MWh for SO_2 and NO_X, respectively. Most of this cost is investment in equipment as opposed to ongoing expenses for O&M and fuel.

It would be wasteful to make this sort of economic commitment to upgrading the existing coal plants if many of them may need to retire in order to meet carbon reduction goals to stabilize climate. Only a few coal units are likely to retire as a result of SO_2 and NO_X policy. A larger number would likely retire as a result of an aggressive policy on CO_2. If the consideration of pollutants proceeds sequentially, then wasteful investments would be made in uneconomic units.

The challenge for environmental policy makers is to implement new policies in a coordinated way, with new regulations developed and announced as soon as reasonably possible. The challenge for industry is to anticipate regulations that are not yet on the books (e.g., CO_2 policy) in making investment decisions to comply with regulations that are immediate (e.g., Phase II of the Clean Air Act Amendments). Clues such as the statements made and agreements signed at meetings on international climate change policy should serve as information factored into current decisions. If carbon reduction policy is designed and implemented soon and coordinated into the response of the system, then much lower-cost possibilities for compliance are available. A mix of hardware investments in the existing plants and retirement of the less efficient of those plants would be the appropriate response.

8. Policies To Promote Environmental Comparability

8.1 Policy Context

In drafting the Clean Air Act and its various amendments, Congress chose to apply more stringent requirements to new electric power plants relative to existing plants for three reasons. First, the cost of installing pollution control technologies was assumed to be significantly higher after a power plant has been constructed. While this assumption is true in general, experience has demonstrated that the costs of complying with environmental regulations can frequently be significantly lower than anticipated at the time regulations are debated and established.

As the most obvious example in the electricity industry, the cost of complying with the SO_2 requirements of the 1990 CAAA is now expected to be less than half the cost expected at the time the provisions were debated. Similar patterns have been experienced with NO_X emission reduction programs in Southern California, with the federal requirements for unleaded gasoline in automobiles, and with the California Low Emission Vehicle Program (Struhs 1997).

The fact that environmental compliance costs tend to be lower than forecasted is partly due to technological innovation, market-based approaches, and increased production levels of control technologies. In addition, a large part of the difference is due to the fact that some environmental regulations provide industry with flexibility in meeting them, and do not necessarily require “bolt-on” control technologies. One of the main reasons that the price of SO_2 allowances is currently so low is that many utilities have switched to using low-sulfur coal (EIA 3/1997). Other alternatives to bolting on control technologies include emissions averaging, varying plant dispatch, improving power plant and fuel-use efficiency, implementing demand-side efficiency measures, developing natural gas facilities, developing renewable resources, and retiring less-efficient facilities.

The second reason for grandfathering was an expectation that the existing power plants would retire in the not-too-distant future, and that the different standards between the two types of plants would not persist for long. However, this has not turned out to be the case; generating units are operating with longer lives than previously expected. In fact, the less stringent environmental standards for existing power plants gives them an economic advantage over new plants, which may allow them to operate longer then they otherwise would (see Chapter 3).

The third reason for grandfathering, as suggested in the discussion of economic theory (see Chapter 2), may have been political expediency. Offering concessions to those who stood to lose from new environmental standards allowed the formation of a consensus around policy action to reduce emissions. Yet the other issues raised by economic theory are relevant as well. To avoid imposing unfair costs on the rest of society, grandfather exemptions should have an expiration date, as soon as possible after the affected parties have been sufficiently protected. In view of the advanced age of many grandfathered coal plants, and the passage of time since the Clean Air Act was adopted and amended, it is appropriate to reconsider the justification for continuing the differential treatment of new and existing sources.

In addition, when Congress developed the different standards for new versus existing plants in the 1970s, retail competition was not allowed among electric utilities -- nor is it likely that retail competition was envisioned by Congress. Therefore, there was less of a need to establish comparable environmental standards across utilities, because additional environmental compliance costs incurred by owners of a new power plant would be recovered from all customers through rates, and would not create barriers to entry or market distortions.

In sum, the rationale for applying different environmental standards to new versus existing plants is much less compelling than it was at the time the standards were established by Congress. The difference in compliance costs for the two types of plants may not be as significant as once expected; existing power plants have operated longer than expected; and the political concessions necessary to reach agreement on the regulations have already been reaped by the relevant stakeholders. Finally, as described in Chapter 6, maintaining this difference in environmental regulations could provide today's electric utilities with an unfair competitive advantage in the newly restructured electricity industry.

Consequently, regulators and legislators should implement policies that establish comparable environmental standards across all ages of generation facilities and all types of generation companies. The following sections describe and evaluate some policies currently available to promote comparable environmental standards.[33]

8.2 Apply New Source Requirements To All Plants

Description

The most direct way to remove the difference in environmental standards is to require all plants to meet the requirements imposed upon new power plants.[34] Existing plants would be required to emit at the lowest achievable NO_X emission rate or install the best available NO_X control technology. This approach would essentially require all existing plants that do not already have control measures to install low-NO_X burners and SCR.

One modification to this approach would be to establish "sunset" provisions, which would remove the exemption from New Source Review that existing plants currently enjoy. There are three criteria that could be used as sunset provisions for grandfathered plants. One is to set a lifetime limit of some fixed period (e.g., 50 years) from the date of operating license approval. Another is to set a spending limit (e.g., a certain fraction of

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[33] There are many policies available to improve environmental quality in a restructured electricity industry, i.e., renewable portfolio standards, system benefits charges, and energy efficiency promotion schemes (Tellus 1995). However, we restrict our discussion here to those policies that reduce or eliminate the difference in environmental standards applied to existing versus new plants.

[34] A similar approach would be to relax the standards applied to new plants to equal those applied to existing plants. However, this approach would not maintain the level of environmental protection envisioned by the Clean Air Act.

the original cost of the plant) for upgrades, plant life extension or repowering. Once the spending limit is passed the plant would be required to meet the same emission standards as new sources. A third option is to specify certain replacements of technology such as the boiler, turbines and/or other components that would require the facility to meet new source emission standards.

Since there already exists a trading system for SO_2 allowances, comparability for SO_2 could be achieved by allocating allowances equitably among all generation companies. Allowances could be allocated to all generation companies on the basis of annual generation times the lowest achievable emission rate or the emission rate of the best available control technology. SO_2 allowances that remain would be placed in a "new source reserve," so that new power plants could be allocated allowances on the same basis as all other plants.

Evaluation

While this approach may be very effective at ensuring comparable environmental standards, it may not be efficient or practical. Requiring all plants to install control technologies is much less efficient than an emission cap and trade system, because it does not provide companies with the flexibility to reduce emissions through less expensive alternatives, such as emissions averaging, alternative dispatching, energy efficiency, renewable resources or plant retirement. Furthermore, such an approach does not provide generation companies an incentive to reduce emissions beyond the standard.

In addition, this policy would be difficult to implement on a state or regional basis. Generation companies that are based in a state or region that does not have this policy would be unable to import power into a region that does, without installing potentially expensive control technologies. Furthermore, this policy is unlikely to have much political support, because it is not market-based.

This policy approach would be most practical to implement through some form of sunset provisions. However, such provisions might not provide much certainty that a significant portion of existing plants would meet the standards for new sources. Many plants may be able to avoid the technology or spending thresholds, given the economic incentive to avoid the new source standards. If the sunset provision were based on unit lifetime (e.g., 50 years), much of the existing fleet of coal plants would not be affected until 2010 or 2020, as indicated in Figures 5.1 and 5.2.

8.3 Emission Cap and Trade Systems

Description

Emission cap and trade systems have received increased attention and support since the 1990 CAAA established the SO_2 allowance cap and trade system. In general, emission cap and trade systems for any particular pollutant require (a) establishing an overall emission cap (in tons) for the pollutant, in order to achieve the desired level of environmental protection; (b) requiring companies generating the emissions to hold at least one emission allowance for every ton emitted each year; (c) allocating emission allowances to the companies generating the pollution based on some scheme deemed to be equitable, and (d) allowing companies to buy and sell emission allowances in an open market.

An emission cap and trade system would have to be explicitly designed to eliminate the differing environmental standards applied to new versus existing plants. As described above in Chapter 4, the primary difference in SO_2 requirements on new versus existing plants is the way in which the SO_2 allowances are allocated to generation companies. Existing generation sources are allocated SO_2 allowances based on historical generation and fuel use, but new sources are not allocated any allowances.

In order to eliminate this difference, the SO_2 allowances could instead be allocated across all generation sources on an equitable basis. This could be achieved by periodically (e.g., annually) holding an auction to allocate all SO_2 allowances across all interested parties (Ackerman and Moomaw 1997). In this way, all generation companies -- those owning existing plants, those owning new plants, and even those planning to operate new plants in the future -- would have equal access to the allowances.

Another option to allocate SO_2 allowances more equitably is to set aside a reserve of allowances for new sources so that they could be assured of receiving some free allowances when they come on line, without exceeding the total emission cap. The formula for calculating SO_2 allowance allocations to new units should be the same as the formula used for old units.

Similarly, new cap and trade systems for NO_X could be established in ways that provide equivalent burdens on new and existing generation facilities. The primary means of achieving equity would be through the equitable allocation of emission allowances.

Evaluation

A cap and trade system provides very clear discipline on generation companies as a whole, because there is an overall cap on the emissions of the pollutant within a particular region. Therefore, they are effective in achieving an environmental objective, depending of course on how the emission cap corresponds to the objective in mind.

The SO_2 allowance trading system has been in operation for over two years, has received general support as an efficient and effective mechanism, and is credited with allowing electric companies to comply with Phase I requirements of the 1990 CAAA at a very low cost. At least 13 states have established similar systems for trading NO_X or VOC allowances (Cantor Fitzgerald 1997). The EPA has proposed using NO_X cap and trade systems in order to assist the OTAG states in complying with current ambient air quality standards for ozone (EPA 9/1997). In addition, the US government, along with many other parties, has proposed that cap and trade systems be established as a means of reducing CO_2 emissions worldwide.

Cap and trade systems can be efficient mechanisms to achieve a particular environmental objective, because they provide a great deal of flexibility to individual polluters. In theory, generation companies have an incentive to select the lowest cost options for reducing emissions, including increases in dispatch of less-polluting resources, installation of more efficient or cleaner generation facilities, installation of control technologies on plants with high emissions, or retirement of plants with high emissions.

Cap and trade systems can be applied on a state, regional or national basis, with a few important exceptions. Ozone, PM and VOC have local or regional -- generally not national -- environmental implications. Consequently, a national or regional trading market for these pollutants might create inequitable and undesirable environmental outcomes.

State and regional regulators and legislators will not likely be able to address the different environmental standards created by the system of allocating SO_2 allowances, because SO_2 is currently allocated on a national basis, using formulas that are very clearly prescribed by the 1990 CAAA. Amendments to the CAA would be necessary to change this allocation process.

In practice, cap and trade systems embody two very important potential problems. Experience with the Clean Air Act Amendments of 1990 demonstrates that there is a significant potential for favoritism in allocating allowances. Sometimes such favoritism may be necessary simply to obtain enough support to establish the cap and trade system. The benefits of such favoritism generally flow to those entities with existing power plants, while new entrants (if they exist at the time) are likely to receive less attention.

Secondly, once allowances are allocated it can be politically difficult -- if not politically impossible -- to change the number of allowances allocated to each firm. This obstacle can pose problems in the future if regulators wish to lower the emission cap in order to meet more aggressive environmental goals, or if regulators wish to allocate allowances more equitably to mitigate the grandfathering effect.

8.4 Emission Performance Standards

Description

Emission performance standards (EPS) are essentially one type of a cap and trade system, with a few key features. An emission performance standard (in lb/MWh) is set for the region, perhaps based upon a total level of emissions (in tons/year) determined to be acceptable. The EPS could be stated in terms of emissions for all kWh sold or, as in some recent proposals, in terms of emissions for all kWh from fossil-fueled generators. Every generation company selling retail electricity into the region would be required to meet the standard, although trading would typically be allowed as a means of compliance. Generation companies whose emission levels are below the EPS for the chosen time period may generate EPS credits that can be sold on an open market. Generation companies whose emission levels are above the EPS will be required to purchase EPS credits to cover their excess emissions.

There are several critical differences between an EPS and a cap and trade system like the one established for SO_2.[35] First, the standard is based on electricity output (in MWh) as opposed to fuel input (in MMBtu). An output-based standard is more efficient than an

[35] In fact, a cap and trade system like the one for SO_2 allowances could be designed without these differences, and therefore would be an EPS. In other words, an EPS is distinguished from the SO_2 allowance cap and trade system by the differences described here. Some EPS proposals do not incorporate all of these differences.

input-based one, because it provides an incentive to reduce fuel input as one means of achieving the standard.[36] Fuel input can be reduced (per MWh of output) by improving the efficiency with which existing units are operated and maintained, repowering older units, relying upon more efficient fuels, and utilizing more efficient technologies.

Second, the standard is applied to the entire portfolio of a generation company's electricity resources,[37] as opposed to being applied on a plant-by-plant basis. A generation company's electricity resource portfolio could be defined as including renewable resources and demand-side efficiency programs, thereby providing companies an incentive to pursue these options as a means of achieving the standard. Increasing the number of options available to meet the standard will in general lower the cost of complying with the standard.

Third, the EPS system does not require that emission allowances be allocated to various generation companies. Instead, EPS credits are generated when a company's emissions are below the standard, creating the pool of credits that must be bought by those companies whose emissions are above the standard. In effect, the EPS is similar to a cap and trade system in which the credits are allocated to generators based upon kWh sold. This feature eliminates the equity problem created by cap and trade systems when emission allowances are allocated exclusively to existing generation companies. New market entrants would, under the EPS approach, automatically be treated equivalently to existing generators.

A EPS will eliminate the difference in environmental requirements applied to new versus old plants if the emission rate is set to be roughly comparable to the emission rate required under New Source Review. For example, under NSR a new coal plant would be required to install BACT or meet LAER, which for NO_X would essentially require the installation of low-NO_X burners and SCR controls. The NO_X emission rate from such a coal plant would be on the order of 0.15 lb/MMBtu, which translates into 1.35 lb/MWh.[38]

This raises the issue of how to set an appropriate cap for the EPS. If the goal of the EPS is to promote comparable environmental standards across all plants, then the emission rate should be at least as low as that required of new plants under New Source Review, and the overall emission cap could be derived from the emission rate. If the goal of the EPS is to achieve a certain level of environmental protection, then the overall emission cap should be set to achieve that level of protection, and the emission rate should be derived from the cap.

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[36] For this reason, the EPA is proposing that the revised New Source Performance Standard for NO_X be developed using an output-based standard (EPA 7/1997). This is the first time the EPA has proposed an output-based pollution standard.

[37] Or, the EPS could be applied to a portion of the portfolio, such as the energy from fossil-fueled generators.

[38] The EPA is proposing that the revised NSPS for NO_X be set equal to 1.35 lb/MWh, based on the 0.15 lb/MMBtu emission rate achievable with low-NO_X burners and SCR, and assuming a heat rate for a new coal plant of 9,000 MMBtu/kWh.

Evaluation

As with cap and trade systems, emission performance standards are likely to be effective at meeting environmental objectives, depending upon how well the total cap corresponds to the particular objectives. An EPS is likely to be even more effective than cap and trade systems in eliminating the grandfathering effect -- primarily because there is no need to allocate emission allowances among generation companies. All sources, old and new, would operate under the same performance standard.

Emission performance standards are also efficient because they provide generation companies with significant flexibility, due to the fact that they are an output-based standard. Relative to input-based standards, an EPS can provide generation companies with additional options for meeting the standard -- including more efficient operation and maintenance of power plants and (if it is an EPS for all kWh) installation of renewable resources.

Emission performance standards can be established on a state, regional, or federal basis. In fact, some states are considering adopting an EPS because it provides them with a mechanism to require out-of-state generation companies to meet the same environmental standards imposed upon in-state companies. One of the risks of independent state-wide EPS efforts is that states may adopt different standards, thereby defeating one of the goals of comparable environmental regulations.

Emission performance standards are market-based, and improve upon the generally accepted cap and trade approach. They have gained increasing support in the past year or two since they were first proposed. The Vermont Public Service Board proposes to implement an EPS as a part of its restructuring plan, and the recently enacted restructuring legislation in Massachusetts requires that an EPS for at least one pollutant be established by 2003 (VTPSB 1996; MA Legislature 1997). At least two federal bills were proposed in the 105th Congress that include a form of an EPS (Jeffords 1997; Pallone 1997).

8.5 Emission Fees

Description

Fees can be applied to each ton of pollutant as an incentive for generation companies to reduce their emissions. In general, there are a variety of approaches to setting an emissions fee, depending upon the objective of the fee (Tellus 1995). The three more commonly considered approaches include the following:

- The fee can be set to represent the societal cost of the pollutant. This approach requires generation companies to pay for emission reduction measures up to the point where the marginal cost of reduction equals the marginal environmental benefit.

- The fee can be set to achieve a particular level of environmental protection. For example, if regulators and legislators wish to limit emissions within a certain cap (in tons/year), then the tax can be set at a level designed to achieve this cap. The tax may need to be adjusted over time to achieve this goal.

- The fee can be designed simply to raise funds that can be used to mitigate or prevent environmental damage.

An emission fee could also be explicitly designed to eliminate the difference in environmental standards between old and new power plants. There are three key questions to consider in designing such an emission fee. Should the fee be applied to all emissions, or just the emissions from existing power plants? At what level should the fee be set? Should the fee be revenue neutral, i.e., should the funds generated by high-emission companies be returned to low-emission companies?

The simplest approach is to apply emission fees to only the existing power plants, i.e., those that have not been subject to New Source Review.[39] It is also preferable to design a revenue neutral emission fee, because this would tend to lower the overall cost to the industry. The level of the fee could then be set to an amount sufficient to raise enough revenues from existing power plants to compensate the owners of new power plants for the additional costs of complying with New Source Review.

Such an approach would compensate owners of new power plants for the grandfathering effect, but it would not encourage existing power plants to reduce emissions to the same level as new plants. As a result, the inequity created by the grandfathering effect would be eliminated, but existing plants would continue to impose greater environmental costs on society than new plants.

Evaluation

In general, emission fees are considered to be efficient mechanisms for achieving environmental goals (depending upon the level at which they are set), because they send the proper price signal to producers and consumers and make up for external costs that tend to be excluded from conventional pricing. They also provide both producers and consumers with a great deal of flexibility to avoid or reduce the associated costs. A revenue neutral feebate approach reduces the overall cost of the policy, and provides positive incentives for reducing emissions at all levels.

However, an emissions fee that is explicitly designed to eliminate the grandfathering effect might not offer some of these advantages. If the fee is designed only to compensate owners of new power plants, then it will not be sending an efficient price signal and generation companies might be more likely to pay the low fee than to investigate alternative options for avoiding it.

Emission fees are likely to face significant political hurdles, because of policy-makers' reluctance to support any measure that resembles a tax -- even if the tax is revenue neutral. In addition, emission fees may require much greater administration than a cap and trade system or an EPS, because of the need to set the fee at an appropriate level.

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[39] The fee could instead be applied to all emissions that exceed the emission rate required of new plants under New Source Review. The fee could be set at a level that is roughly equivalent to the cost of the control technology required under NSR. In this way, owners of existing plants would either install the same types of control options as new sources, or would pay an equivalent cost. However, establishing such a fee would be difficult, if not impossible, because the cost of complying with NSR would vary significantly for each existing power plant.

Emission fees to eliminate the grandfathering effect could be applied on a state, regional, or national basis, and would be more effective if they cover as much of the electricity market as possible. If emission fees are limited to a particular state or region, then administrators may have problems treating out-of-state power plants. Applying a fee to out-of-state plants might violate the Commerce Clause. If not, administrators will be faced with the challenge of determining whether and how to compensate new out-of-state power plants for the costs of meeting the requirements of NSR.

8.6 Emissions Disclosure

Description

Once retail access is allowed, many retail customers may consider environmental impacts as one of the factors in selecting a generation supplier. In the retail competition pilot programs that have been conducted to date, many marketers have been advertising "green power" as a means of luring environmentally conscious customers.

If a significant number of customers prefer to purchase electricity from cleaner generation suppliers, then the inequity created by the grandfathering effect might be offset somewhat. Generation companies maintaining a portfolio of older plants with higher emission rates might find it difficult to market their product to certain customers, relative to companies with newer plants and lower emission rates.

However, in order for customer preference to offset the grandfathering effect, customers must be adequately informed of the environmental impacts of all generation suppliers. In order to provide this information, generation companies could be required to disclose all of their emissions to customers on a uniform basis.

Customer information is an essential aspect of a competitive market, and many regulators and legislators in states that are establishing retail competition are developing uniform disclosure requirements for all generation companies (RAP 1997). In all cases, companies are required to reveal pricing information in a way that allows for meaningful customer choices based on cost. In some cases, companies are also required to disclose information about environmental impacts.

Some generation suppliers plan to market green products (e.g., electricity from renewable resources) out of a larger generation portfolio that might also include many other resources with high environmental impacts. Consequently, some stakeholders argue that companies should have the ability to disclose their emissions of only the product being marketed, without revealing the emissions of other resources in the generation portfolio. Others counter that emissions should be disclosed on a company-wide basis, to prevent companies from essentially allocating their green power to customers that are willing to pay for it, and allocating all their dirty power to those customers that do not care about environmental impacts -- without actually changing their mix of clean versus dirty resources.

If companies are allowed to disclose their emissions on a product basis, as opposed to a company basis, then customers will not be provided with information regarding the different emissions from new power plants versus old. Therefore, if regulators and legislators wish to use environmental disclosure as a means of helping to offset the grandfathering effect, then each generation company's emission rates would have to be disclosed to all customers on a company-wide basis.

Furthermore, all generation companies would have to be required to disclose their emissions, not just those that seek to market green power. There may be a large segment of customers who are not interested in paying a significant premium for green power but would prefer a low-emission generation company to one with high-emissions. In order to offset the grandfathering effect, customers would have to have the information necessary to make this distinction.

Evaluation

Emissions disclosure will only offset the grandfathering effect to the extent that customers care about environmental impacts in selecting their generation company, and to the extent that they are willing to pay more for cleaner power. While some generation companies are clearly planning to market green power to customers, it is unclear how customers will respond.

Given that a large portion of electricity customers (i.e., most industrial, most commercial, and many residential) is unlikely to use environmental impacts as a major criterion in selecting a generation company, this policy should not be relied upon as a means of eliminating the grandfathering effect. It may offset the effect some, but only to a very small degree.

Nevertheless, for other reasons emissions disclosure is an important public policy in a competitive electricity market. It provides customers with information necessary for making meaningful decisions, and it helps to prevent companies from making environmental claims that are either misleading, confusing, or false. Mandatory emissions disclosure should be seen as an important part of a competitive electricity market, but it has little to do with the grandfathering effect.

8.8 Summary Of Policy Options

Table 8.1 presents a summary of the policy options discussed above.

Table 8.1 Summary Of Polices To Promote Environmental Comparability

	Apply New Standards To All Plants	Cap and Trade Systems	Emission Performance Standard	Emission Fees	Emission Disclosure
Description	For NO_X require existing plants to meet BACT. For SO_2 allocate allowances equitably, keep reserve for new sources. Could impose through sunset provisions.	Establish emission cap; permit allowance trading. Allocate allowances equitably; using auction for all sources, or reserve for new sources.	Similar to cap and trade system. Standard is output-based. EPS applied to company portfolio. Allocation of allowances not required.	Apply to plants that have not met NSR. Fee could be set only to compensate new plants. Or, fee could be set so that old plants achieve NSR.	All generation suppliers required to disclose emissions in a uniform format. Emissions disclosed on a company-wide basis.
Effective In Removing Grandfather Effect?	Potentially.	Yes, depending upon cap used. SO_2 allocation can only be done at federal level.	Yes, depending upon cap used.	Partially, if fee used only for compensation. Fully, if fee set so that old plants achieve NSR.	No, depends upon customers interest in, and willingness to pay for, clean power.
Efficient?	No. Partially internalizes environmental costs.	Yes.	Yes.	Yes, if fee set so that old plants achieve NSR.	No. Does not internalize environmental costs.
Comments	Unlikely to have much political support. Sunset provisions might not be effective.	Risk of favoritism in allocating allowances. Difficult to change allowance allocations over time.	Offers simplicity in not allocating allowances. Offers additional benefit of addressing imported power.	Impractical politically. Does not offer any advantages over EPS. Difficult to set right level	Necessary for competitive market, but not sufficient for removing grandfathering effect.

9. Further Research

There is considerable need for further research on the topics addressed in this report. We found that the academic literature on grandfathering is largely focused in the area of tax policy. More analysis of grandfathering in the context of environmental policy would be useful.

In addition, there are important related policy issues that we have not addressed here. These include:

- What do the prospects for impending CO_2 and mercury regulations imply for a strategy to reduce SO_2 and NO_X emissions from the electricity sector?
- What are the appropriate levels of air emissions for the electric power sector, given the costs and benefits to society?

With regard to the quantitative analysis presented here, questions that are ripe for further research include the following:

- What is the likely timeline for improvements to the performance and cost of gas combined-cycle generating technology?
- What are the prospects for additional cost reductions at existing plants, including lower fuel costs, O&M costs, and emission control retrofit costs?
- Are there important costs omitted from the plant data reported to FERC?
- How do options such as co-firing with gas and repowering older plants fit into this picture?
- What are the specific circumstances of the individual existing units identified here as at-risk? For example, there may be data errors or one-time anomalies, units operating in transmission constrained areas, or particular above-market coal contracts.
- How do the economics of continued operation look for existing *oil-fired* power plants in an environmental comparability scenario?
- How would economic feedbacks figure into the scenarios? For example, if natural gas use increased sharply and coal use decreased (as in a CO_2 policy scenario) how would the market prices for these fuels respond?
- What do the results of generation divestitures imply for the economic value of existing power plants?
- How would our results change if the economic analysis included simulation of system dispatch, allowing units to find their appropriate capacity factor in the context of regional electricity markets?

We believe that this last question is particularly susceptible to useful analysis in the near-term, as it could be conducted with readily available data (regional generating unit performance data and loads) and methods (production costing simulation models). On one hand, if the new gas combined-cycle capacity will fall into the market-based dispatch after existing generators, then the new capacity will primarily serve new load, at low capacity factors. In this case increasing levels of air emissions can be expected. On the other hand, to the extent that the new gas fits into the dispatch order before existing generators it will run at higher capacity factors, displacing existing generation and resulting in windfall air emissions reductions. If this occurs, it will tend to be an incremental phenomenon, displacing existing generation slowly over time. Region-specific studies involving dispatch simulation would help to determine whether and to what extent this gradual turnover of the capital stock can be expected to occur. At the same time, policies should be put in place to ensure that an appropriate rate of replacement does occur and that emerging electricity markets function without unnecessary distortions.

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