Figure 6. Changes in Capacity by Fuel and Technology in 2007 Due to the NOx SIP Call

Source: U.S. Environmental Protection Agency 1998a.

d. New Source Review and New Source Performance Standards

(1) Policy Overview

The New Source Review (NSR) program requires that new facilities and facilities undertaking modifications that would lead to increased emissions obtain NSR permits. A source must undergo NSR under the following two conditions:

1. Non-attainment Program—The source must undergo NSR if the source is located in an area currently in non-attainment for a particular pollutant.

2. Prevention of Significant Deterioration (PSD)—The source must undergo NSR in an area in attainment if the source emits above a threshold quantity as defined in the PSD regulations.

NSR requires at minimum that Best Available Control Technology (BACT) be applied for any emissions subject to regulation.

On November 3, 1999, the U.S. Department of Justice, on behalf of the EPA, filed suit against seven investor-owned electric companies and the Tennessee Valley Authority (TVA) (U.S. Department of Justice 1999). The suits contend: (1) that the investor-owned electricity companies and TVA undertook modifications to particular plants that the EPA claims trigger NSR; (2) that the companies did not obtain the proper permits and install pollution control equipment required under NSR. The electric companies maintain that these modifications were a part of "routine maintenance" that can be undertaken without triggering NSR (Clean Air Compliance 1995c).

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Before this recent litigation, the EPA in 1992 began a multi-party process—including representatives from industry, environmental organizations, states, and the EPA—to revise the NSR regulations. Several issues being addressed in this process are particularly relevant to electric power plants (U.S. Environmental Protection Agency 1996, Environmental Reporter 1999, Martineau and Novello 1998). These issues include:

- **Modifications to trigger NSR**—Under discussion is the approach to measuring the emissions increases from modifications and the level of increased emissions that would trigger NSR.

- **Routine repair and replacement**—Under discussion are the kinds of routine repair and capital replacement that would qualify for an exemption from NSR requirements.

- **Voluntary cap on source emissions**—Under some proposals (including revisions proposed by the EPA in 1996), any plants accepting a voluntary cap on emissions would not be subject to the NSR process. Thus, unlimited modifications could occur as long as plant emissions do not exceed the cap (U.S. Environmental Protection Agency 1996).

- **Relationship between NSR and existing cap-and-trade programs**—There is concern that NSR not negate the flexibility that cap-and-trade programs provide for achieving emissions compliance. The NSR process often requires installation of BACT, which may preclude compliance flexibility, including allowance purchases, encouraged by cap-and-trade programs.

- **Netting**—The NSR contains a netting provision that allows sources to avoid the NSR process by offsetting new emissions with reductions from other emissions sources within the same facility. Currently, many facilities avoid the NSR process by obtaining offsets. Elimination of this provision is under discussion.

In contrast to the NSR program, which requires that sources obtain source-specific permits, NSPS specify a set of technology standards for all new and significantly modified sources. These technology standards are prescribed for particular types of facilities and sources. While not directly related to the NSR program, these standards create a “floor” for the case-by-case NSR technology analyses (Martineau and Novello 1998).

In 1999, the EPA published revisions of the NSPS for NOx emissions from fossil fuel–based steam generation units (40 CFR part 60 1999). The standard, which is based on a coal-based unit with SCR technology, applies to all fossil fuel–based generation units regardless of fuel type used by the unit. The form of the standard varies between output-based standards for new electricity generation units and input-based standards for existing electricity generation units and industrial units. This revised standard is predicted to reduce NOx emissions from new and modified sources by 42 percent from current levels (U.S. Environmental Protection Agency 1997b).
(2) Policy Impact

NSR and NSPS require new and modified sources of air emissions to install pollution control equipment. These requirements would add costs to generation facilities burning fossil fuels or biomass. Such requirements would not apply to nuclear, hydroelectric, and non-hydro renewables with the exception of biomass. To the degree that these requirements impose differential costs across different types of facilities, they could affect the generation supply mix.

The EPA projects that the revised NSPS NOX standards would result in costs of about $40 million annually across all affected sectors, based upon the installation of either SCR or SNCR technologies (U.S. Environmental Protection Agency 1997b). These controls would increase the cost of producing steam for new power generation units about 2 percent. The EPA estimates that the regulations will affect 17 new electricity generation boilers and 381 new industrial boilers over its first five years (U.S. Environmental Protection Agency 1997b).

e. National Ambient Air Quality Standards—PM2.5 and 8-hour ozone

(1) Policy Overview

Following passage of the 1970 Clean Air Act, the first National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM) were set in 1971. Revisions were made to the ozone standard in 1979 (Martineau and Novello 1998). States have the responsibility to develop SIPs that demonstrate how the ambient standards will be met within their jurisdictions.

In 1997, the EPA issued new NAAQS for ozone and PM, although these rules have not yet been implemented because of legal challenges. The major changes in the particulate matter standards are:

- **First standard for particulate matter less than 2.5 micrometers**—The previous PM standard was for particles less than 10 micrometers (PM10). The new PM2.5 rule sets ambient standards for particles less than 2.5 micrometers in addition to the PM10 standards.10

- **PM2.5 standards more stringent than PM10 standards**—The greater stringency of the new PM2.5 standards would have two effects. First, many regions would need to increase the level of required emissions reductions for combustion sources beyond the level necessary to achieve the PM10 standards. Second, many regions not required to undertake reductions under PM10 standards would be required to undertake reductions under PM2.5 standards.

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10 The EPA is required to perform NAAQS reviews every five years (Martineau and Novello 1998).
11 The new PM2.5 rule set the average annual standard for particles less than 2.5 micrometers in diameter at 15 μg/m³ and the average 24-hour standard at 65 μg/m³.
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- Particulate matter standards affect non-PM emissions as well—The new PM_{1.0} standard would affect not only direct PM emissions from electric utilities but also emissions of NO_{x}, SO_{2}, and VOCs. Once emitted into the atmosphere, these other emissions can be transformed through chemical reactions into PM_{1.0}.

The ozone standards also introduced important changes from the earlier standard. These are:

- New method for measuring ozone levels—The new ozone standards would change the method for measuring ambient levels from a one-hour maximum average to an eight-hour maximum average.

- New concentration levels for ozone—The new method for measuring ozone is accompanied by revised concentration levels for measuring attainment. Under the one-hour standard, a region is in attainment for ozone “when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is equal to or less than one . . .” (57 Federal Register at 13,489 and 13,522). Under the eight-hour standard, a region is out of compliance if the three-year average of the fourth-highest daily maximum eight-hour average concentration is greater than 0.085 ppm.

- More stringent ozone requirements—The net result of the changes in method and concentration levels is to make the ozone standard more stringent. This greater stringency would require greater emissions reductions to achieve compliance.

A ruling by the U.S. Court of Appeals for the D.C. Circuit, in Washington, D.C., has created substantial uncertainty over the status of these NAAQS. On May 14, 1999, the D.C. Circuit ruled in the case of American Trucking Associations, Inc., et al. v. United States Environmental Protection Agency that the EPA’s rationale for setting the ozone and particulate matter NAAQS under the CAA potentially represents an unconstitutional delegation of legislative authority and ordered the EPA to develop “intelligible principles” supporting new standards. The Supreme Court currently is considering this case.

(2) Policy Impact

Implementation of the new eight-hour ozone NAAQS likely would require additional emission reductions from the electric power sector in various states. The extent of these reductions, however, has not been estimated; the regulatory analyses of the new standards did not address the potential effects on electric power emissions. The incremental costs and impact of these standards likely would depend on the implementation status of other policies, such as the OTC NO_{x} Budget Program, NO_{x} SIP Call, or the Section 126 petitions, and the effectiveness of these policies at reducing ambient ozone concentrations.

12 The EPA’s ozone rule was remanded for a number of additional reasons, most notably limitations to the EPA’s ability to enforce new ozone standards based on Subpart 2 of the 1990 CAAA and the EPA’s failure to examine possible health benefits of ozone (American Trucking Associations, Inc., et al. v. United States Environmental Protection Agency, 195 F.3d 4; D.C. Cir. 1999).

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2. \( \text{SO}_2 \) Controls

Various provisions of the CAA regulate emissions of \( \text{SO}_2 \). Figure 7 shows that electric utilities account for about 67 percent of \( \text{SO}_2 \) emissions. This section discusses the various provisions and recent proposals related to utility \( \text{SO}_2 \) emissions.

Several major policies regarding \( \text{SO}_2 \) emissions have been developed and proposed in the 1990s, largely in response to the 1990 CAAA. These policies include:

- **Title IV \( \text{SO}_2 \) Requirement**—Title IV of the 1990 CAAA developed a national cap-and-trade program for \( \text{SO}_2 \) emissions from power plants.
- **NSPS and NSR for \( \text{SO}_2 \)**—Controls on new sources of \( \text{SO}_2 \) under the NSPS and NSR requirements.
- **Regional Haze Requirements**—Requirements to reduce haze at all National Parks and Wilderness areas, potentially requiring reduction of \( \text{SO}_2 \), a precursor to haze, in all 50 states.
- **\( \text{SO}_2 \) NAAQS**—While the EPA determined in 1996 that no changes to the current \( \text{SO}_2 \) NAAQS were necessary at this time, environmentalists challenged this decision. A recent court ruling has remanded the decision back to the EPA for further clarification.
- **Particulate Matter NAAQS**—Revisions in the NAAQS for particulate matter, although a recent legal action calls these standards into question.

*Figure 7. Electric Power Share of \( \text{SO}_2 \) Emissions*

Source: U.S. Environmental Protection Agency 1998b.
a. Title IV SO₂ Program

(1) Policy Overview

Title IV of the 1990 CAAA mandates a nationwide cap-and-trade program for SO₂ emissions from coal-fired generation units. The major elements of the program are summarized below (Ellerman et al. 1997):

- The program targets only the electric power sector, eventually requiring about a 50 percent reduction in SO₂ emissions from 1980 emissions levels.
- The program is implemented in two-phases:
  - In Phase I, emissions from 263 units were capped at 8.69 million tons in 1995, falling to 6 million tons in 1999. The eventual number of units capped in 1995 increased to 445 due to the substitution and compensation provisions that allowed Phase II units to opt-in early.
  - Phase II started in 2000 and expands the affected plants to include virtually every fossil fuel–based electric generating unit, more than 200 units. The emissions cap is 9.4 million tons until the year 2010, when it is lowered to 8.95 million tons SO₂ per year.
- The cap is imposed nationally, with no regional constraints on emissions trading.
- Allowances are distributed to utilities using a formula based largely on a unit’s heat utilization.¹³
- Allowances may also be banked for use or trade in future years.

(2) Policy Impact

Many analyses have examined the impact of the Title IV SO₂ Program, partly due to its importance as one of the first large-scale cap-and-trade programs. Several recent studies, which incorporate data on Phase I and the effect of more recent developments on Phase II implementation, provide insights into the impact of both phases of the program.

Experience with Phase I indicates that emissions trading can reduce the costs of achieving emissions targets. A study by the MIT Center for Energy and Environmental Policy Research (CEEPR) concludes that emissions trading reduced Phase I costs by 25 to 34 percent (Ellerman et al. 1997).¹⁴ A study by Resource for the Future (RFF), however, suggested that the savings from trading were more limited (Carlson et al. 1998). Table 4 shows that even with these cost savings, the Phase I SO₂ program resulted in estimated annual compliance costs that ranged from $770 million to $960 million. The average cost per ton was estimated by CEEPR at $187 to $210 per ton of SO₂, which was much higher than

¹³ There were a number of departures from this basic rule, particularly for Phase II units (Joskow and Schmalensee 1997).

¹⁴ The CEEPR recently has estimated that emission trading will reduce the cost of achieving the Phase II emission reduction goal by about half. See Ellerman et al. 2000.
actual market prices of this period, reflecting the large degree of initial over-compliance (i.e., installation of excessive pollution control equipment) (Ellerman et al. 1997). The RFF study estimates the average marginal cost, weighted by each facility’s generation, at $180 per ton, which is also consistent with over-compliance by a large number of facilities (Carlson et al. 1998).

Electric utilities used a variety of means to comply with Phase I of the SO2 trading program, including fuel switching or blending, 53 percent, allowance purchases, 27 percent, and installation of pollution control technology, 16 percent (U.S. Department of Energy 1997). Seven affected facilities, representing 1,342 megawatts or 1.5 percent of total affected capacity, have closed, although other factors played a large role in the closure decisions.

Phase II will impose additional compliance costs, although the costs will be delayed due to the large quantity of banked allowances created during Phase I. These banked allowances are expected to delay the full imposition of the Phase II cap until 2007 to 2010 (Smith et al. 1998). As shown in Table 4, once the banked allowances are used, the incremental costs of Phase II are estimated to range from $0.89 to $1.10 billion per year in 2010. Due to a variety of factors, such as a reduction in the cost of fluidized gas

15 The initial over-compliance was due to a variety of factors that led firms to expect higher SO2 allowance prices than actually occurred. Decisions to invest in expensive scrubbers were made based upon these relatively high SO2 prices. See Ellerman et al. 1997, and Bohi and Burtraw 1997.
16 The Electric Power Research Institute (as referenced in Smith, Platt, and Ellerman 1998) estimates that lower coal utilization, possibly due to “major new regulations,” might cause incremental costs to fall as low as $0.39 billion ($1997).
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desulfurization (FGD) technology and greater access to low-sulfur coal, these costs are substantially lower than initial estimates produced before the implementation of Phase I. Average costs are estimated to be about $200 per ton, while marginal costs are estimated to range from $276 to $498 per ton.17 These costs are higher than the current allowance prices, which are less than $150 per ton.

The SO₂ cap-and-trade program increases the cost of generating electricity from coal-fired units. As shown in Table 4, Phase I has increased the cost of electricity from coal-fired units between $0.44 and $0.55 per megawatt-hour. Phase II is estimated to increase costs between $0.41 and $0.53 per megawatt-hour.

b. *New Source Review and New Source Performance Standards*

(1) **Policy Overview**

As described above, all new power plants or existing power plants making substantial modifications are required to undergo a NSR permitting process or comply with NSPS; the specific requirement depends on the location and quantity of emissions generated. The NSPS require that sources install BACT to control SO₂ emissions (Martineau and Novello 1998). As noted above, the EPA is in the process of revising the NSR process and has filed suit against seven investor-owned electric companies and the TVA alleging NSR violations.

(2) **Policy Impact**

NSR and NSPS require new and modified sources of air emissions to install pollution control equipment. These requirements would add costs to generation facilities burning fossil fuels or biomass. Such requirements would not apply to nuclear, hydroelectric, and non-hydro renewables, with the exception of biomass generation. To the degree that such requirements impose differential costs across different types of facilities, they may affect the mix for power generation.

c. **National Ambient Air Quality Standards—SO₂ and PM₁₀**

(1) **Policy Overview**

As noted above, the CAA requires the EPA to set a NAAQS for SO₂. The NAAQS for SO₂ was last revised in 1978. Although the EPA in May 1996 determined that there is no need to revise the SO₂ standard, environmentalists challenged this decision. In January 1998, the D.C. Circuit remanded the EPA's decision that no new SO₂ NAAQS was needed to the EPA for clarification (American Lung Association et al. v. United States Environmental Protection Agency, 96-1235 (D.C. Cir., decided, January 30, 1998)).

The NAAQS for particulate matter also affects requirements for reductions in SO₂ emissions, since SO₂ can be transformed into particulate matter through atmospheric processes.

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17 This range reflects variation in a limited number of parameters. Incorporation of other uncertainties could raise costs to about $600 per ton (Smith, Platt, and Ellerman 1998).
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reactions. The 1997 revisions to the particulate matter standard could lead to additional reductions in SO₂ emissions, due to a need to comply with new standards for particulate matter smaller than 2.5 micrometers. As noted earlier, legal actions put the new PM₂·₅ standard in doubt.

(2) Policy Impact

The potential PM₂·₅ standards may require significant reductions in SO₂ emissions in many regions. The EPA has not stated whether national federal programs would be implemented as part of a compliance program. With respect to the electric power sector, the EPA appears to prefer a further tightening of the Title IV SO₂ cap (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a). The EPA has not announced the quantity of additional SO₂ emissions reductions that would be sought if the SO₂ cap were further tightened, but it has suggested that additional reductions of 45 to 70 percent below the Title IV Phase II cap would be likely (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a). The EPA's 1997 Regulatory Impact Assessment (RIA) for the PM₂·₅ standard assumes a 60 percent reduction in SO₂ emissions relative to current Title IV programs. This reduction implies a target of 3.58 million metric tons of SO₂, compared to a 9.4 million metric ton cap under Title IV (U.S. Environmental Protection Agency 1997c). A more recent EPA analysis considers four SO₂ reductions scenarios ranging from 57 to 71 percent; these scenarios imply 2007 targets of 4.2 million tons and 2.8 million metric tons, respectively (U.S. Environmental Protection Agency 1999a). Actual emissions in the year that caps are tightened may exceed emission caps due to banking of allowances.

Several studies have analyzed the impacts of further tightening the SO₂ cap, including two studies by the EPA and a study by the Electric Power Research Institute (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a, Electric Power Research Institute 2000). These studies, which examine a range of possible reductions, provide some perspective on the possible impact from additional SO₂ reductions. Table 5 reports estimates of the annualized cost and cost per kilowatt-hour for attaining the SO₂ targets analyzed in these studies. The incremental costs of additional reductions beyond Phase II requirements are estimated to be between $2.2 and $3.4 billion annually depending on the emission target, which ranges from 2.8 million metric tons to 4.5 million metric tons. The EPRI results suggest that costs would be somewhat higher than those reported by the EPA.

Table 5 also reports estimates from the Reason Public Policy Institute (RPPI) of the combined costs to the electric power sector of revised ozone and PM₂·₅ standards (Smith et al. 1997). This study estimates the full additional cost to utilities of achieving compliance in all regions to be $20.4 billion annually. Since this cost estimate is incremental to the NOₓ SIP Call, it is likely that the majority of these costs are attributable to the PM₂·₅ rather than the ozone standards. Results from the RPPI study differ from the EPA and EPRI studies because the RPPI study is based on reductions necessary to achieve compliance in all regions. In contrast, the EPA and EPRI studies only examine a tightening of the SO₂ cap, which may not be adequate to achieve full compliance in all regions (U.S. Environmental Protection Agency

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### Table 5. Estimates of the Impact of Additional SO\(_2\) Reductions

<table>
<thead>
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<th>Study</th>
<th>Annual Emissions Cap(^1) (million mt)</th>
<th>Total Cost ((\text{billion } \text{dollars})^2)</th>
<th>Annual Average Cost ((\text{dollars }/\text{MWh})^2)</th>
<th>Generation Capacity ((\text{billion } \text{kWh}))</th>
<th>Generation Capacity ((\text{billion } \text{kWh}))</th>
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<td>$1.06</td>
<td>-2</td>
<td>-47</td>
</tr>
<tr>
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<td>$1.53</td>
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<td>NR</td>
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<tr>
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<td>$20.4</td>
<td>$9.90</td>
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</tr>
</tbody>
</table>

NR—not reported.

1 Actual emissions at the date when the cap is tightened further may exceed emissions caps due to banking of allowances.

2 Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).

3 Average cost estimates were derived by dividing the total costs by estimates of coal-fired generation in 2010 from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

4 The SO\(_2\) trading cap is for a scenario that achieves partial attainment with the PM\(_{2.5}\) standards. There are 30 potential non-attainment counties.

5 Includes the costs of reducing NO\(_x\) as well as SO\(_2\) emissions to comply fully with both revised ozone and PM\(_{2.5}\) standards. Since the costs of reducing NO\(_x\) under the SIP Call are not included, these estimated costs likely are attributable to SO\(_2\) reductions.


The 1999 EPA study also reports the impact of reductions in the SO\(_2\) cap on the electricity fuel mix. The EPA reports that additional SO\(_2\) reductions would be achieved primarily through installation of FGD control technology and fuel switching, with relatively limited increases in natural gas combined-cycle technology. As shown in Figure 8, the EPA predicts that combined-cycle natural gas capacity in 2010 would increase by 7 gigawatts under the 2.8 million metric ton target, a 6 percent increase in natural gas capacity. Coal capacity would decrease by 3 gigawatts, a 1 percent decrease in capacity. Predicted changes in generation are larger, reflecting increased utilization of existing gas-fired units and decreased utilization of coal-fired units. As shown in Figure 9, coal-fired generation is predicted to decrease by 8.5 billion kilowatt-hours, a 4 percent decrease, and gas-fired generation would increase by 84 billion kilowatt-hours, an 11 percent increase.
Figure 8. Changes in Coal and Natural Gas Capacity in 2010 Due to Additional SO₂ Reductions beyond Title IV SO₂ Requirements

Low EPA corresponds to an SO₂ cap of 2.8 million metric tons, and High EPA corresponds to an SO₂ cap of 4.2 million metric tons.

Source: U.S. Environmental Protection Agency 1999a.

Figure 9. Changes in Coal and Natural Gas Generation in 2010 Due to Additional SO₂ Reductions beyond Title IV SO₂ Requirements

Low EPA corresponds to an SO₂ cap of 2.8 million metric tons, and High EPA corresponds to an SO₂ cap of 4.2 million metric tons.

Source: U.S. Environmental Protection Agency 1999a.
In summary, further reducing SO₂ emissions to achieve compliance with a PM₃₅
NAAQS would result in substantial additional costs. Estimates of these additional costs
range from $2.2 billion to $3.4 billion depending upon the national SO₂ emission target and
when it would be implemented. These cost estimates, however, assume that reductions by
electric utilities are limited to a further tightening of the national cap. Costs could be
substantially greater if further electric power SO₂ reductions were sought to comply with the
revised NAAQS for particulate matter in all locations.

d. Regional Haze

(1) Policy Overview

The 1977 amendments to the CAA established a national goal to eliminate existing
(and prevent future) visibility problems in 156 National Parks and Wilderness areas (called
Class 1 areas), due to human sources of emissions. Visibility problems are due to regional
haze, which is created by various pollutants, including particulate matter, sulfates, and
nitrates. In 1980, the EPA promulgated rules that would require emission reductions if
visibility problems were reasonably attributable to a single emission source. In July 1999, the
EPA published a final rule that would require reductions if visibility problems in Class 1 areas
were caused by groups of facilities (64 Federal Register 35,715 1999). This rule has been
challenged in the D.C. Circuit by several industries. Implications of this ruling include:

- Incorporation of regional haze into SIPs—This rule would require states to
  incorporate actions to reduce regional haze into their SIPs.

- All states affected—Because the Class 1 sites are distributed across the country
  and many of the targeted pollutants are transported regionally, all 50 states are
  required to develop long-term plans to meet "reasonable progress goals."

- Targets not defined—The EPA specified that SIPs must achieve "reasonable
  progress goals," though they did not specify what these progress goals should be.¹⁸

- Best Available Retrofit Technology (BART) requirements—The haze rule does
  require states to identify BART for up to 26 different types of emissions sources
  placed into operation between 1962 and 1977. The rule does allow flexibility in
  BART requirements if states propose alternative measures, such as an emissions
  trading program, that achieve more progress than source-by-source BART
  controls.

¹⁸ A goal of one decameter visibility improvement per decade was included in the proposed version of
the rule. National progress goals were not specified in the final version because of the variation in
improvements necessary to meet the long-run goal of achieving background levels of visibility
impairment within 60 years.

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- Regional planning efforts—The EPA is encouraging regional planning efforts to address visibility impairment at the Class 1 areas since many sites receive emissions from more than one state.

The regulations include specific provisions allowing states in the Grand Canyon Visibility Transport Commission (GCVTC) to meet regional haze SIP planning requirements based on recommendations of the GCVTC. Drawing upon these recommendations, the Western Regional Air Partnership is currently developing a regional SO₂ reduction plan that would phase-in emissions targets from 2003 to 2018. Several proposals are currently under consideration (Western Regional Air Partnership 2000). These proposals include a cap-and-trade program for stationary source emissions, with proposed emission caps ranging from 373,000 to 635,000 tons of SO₂ annually.

(2) Policy Impact

The impact of regional haze regulations will depend on how individual states implement their SIPs, the degree of regional coordination, and the levels of improvement in visibility sought. The EPA's Regulatory Impact Assessment (RIA) projects that the costs may range from $0.9 billion to $5.5 billion annually (updated to 1999 dollars), depending upon the magnitude of visibility improvements sought and the deadline by which such improvements must be achieved (U.S. Environmental Protection Agency 1997). These costs are incremental to the costs of the proposed NAAQS for eight-hour ozone and PM_{2.5}. The costs to the electric power sector, however, are not provided in the RIA. One study projects that the costs of one deciview²⁰ of improved visibility for the West alone would be about $5 billion annually, and that the costs of subsequent deciview improvements would be substantially larger (Smith 1997).²¹

Haze regulations are likely to have the largest impact on sources in locations upwind from affected National Parks and Wilderness areas and those producing the most significant emissions. Western states are likely to incur higher costs than eastern states (Smith 1997). Since SO₂ emissions are among the most significant precursors to regional haze, stationary fossil fuel sources, particularly coal-fired power generation units, are likely to be among the most affected sources.

3. Mercury Controls

Section 112 of the CAA requires the EPA to set standards for hazardous air pollutants (HAPs). These standards are called National Emissions Standards for Hazardous Air Pollutants (NESHAP). The EPA currently is considering establishing a NESHAP or comparable regulatory program for mercury emissions from electric utility power plants. Electric

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¹⁹ These states include Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming.

²⁰ A deciview is a visibility scale that expresses uniform changes in haziness across the range of visibility conditions, from pristine to extremely hazy (40 CFR 35714 1999).

²¹ The year of this cost estimate is not specified.
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utilities account for about 30 percent of national, anthropogenic mercury emissions, as shown in Figure 10.

a. Policy Overview

Section 112 of the 1990 CAAA contains several provisions related to emissions of mercury from electric utility power plants (Center for Clean Air Policy 1998):

- **Maximum Achievable Control Technology (MACT)**—Electric power plants emit a number of HAPs, including mercury. The MACT program is one of the regulatory options available to the EPA under Section 112 to address sources that emit HAPs.22

- **The Great Waters Program**—The EPA may require additional controls on sources that emit HAPs in levels that endanger human health and the environment in the Great Waters area, which include the largest inland lakes and coastal areas.

- **Utility HAPs Report**—Section 112(n)(1)(a) requires the EPA to submit a report to Congress on threats to public health that stem from the release of HAPs from electric utilities. The 1990 CAAA also gave the EPA the authority to regulate electric utility HAP emissions if the Agency deems it necessary.

The Utility HAPs Report was released in February 1998, finding that “on balance, mercury from coal-fired utilities is the hazardous air pollutant of greatest public health concern,” although the extent of exposure due to power plants is uncertain (U.S. Environmental Protection Agency 1998d). The report notes that the “EPA has not been able to identify any currently demonstrated, feasible, and commercially available technology for

![Figure 10. Electric Power Share of Anthropogenic Mercury Emissions](image)

Source: U.S. Environmental Protection Agency 2000b.

22 Sources within a controlled industry category that emit at least 10 tons per year of one HAP or 25 tons per year of two or more HAPs must comply with MACT requirements.

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reducing various chemical forms of mercury emission from coal-fired utilities" (U.S. Environmental Protection Agency 1998d).

The National Academy of Sciences (NAS), as mandated by Congress, issued a report in July 2000, indicating that the risk of adverse health effects from exposure to mercury is low for the majority of the American public. The NAS report suggested that additional research is necessary to identify and reduce possible risks among sensitive population groups.

After considering the findings of the Utility HAP Report and the NAS study, the EPA recently made a regulatory determination for mercury (U.S. Environmental Protection Agency 2000b) in which the agency decided to move forward with the development of a proposed rule. A proposal is expected by December 2003, with a final rule issued about one year later. The EPA is currently reviewing preliminary data from the Mercury Emissions Information Collection Effort, which is focusing on emissions from 84 coal-based electric units and the mercury content in coal burned at over 1,000 units (Clean Air Compliance Review 1999a).

b. Policy Impact

A NESHAP for mercury would target predominantly coal-fired electric power units (Center for Clean Air Policy 1998, U.S. Environmental Protection Agency 1998c). Although many control options exist for reducing mercury emissions, there is limited information on the cost and effectiveness of these options when used on coal-fired units. A report by the Center for Clean Air Policy (CCAP) reports costs for six approaches. Aside from coal switching, all estimates are greater than $33,000 per pound of mercury (Center for Clean Air Policy 1998). The EPA has produced two studies on the costs of mercury control at coal-fired units. Its first report estimated that 90 percent mercury reduction could be achieved at an average cost of $67,000 to $70,000 per pound (U.S. Environmental Protection Agency 1997a). A recent report produced revised estimates of $28,000 to $34,000 per pound (U.S. Environmental Protection Agency 1999a). In comparison, sectors already subject to MACT typically achieve emissions reductions for less than $5,000 per pound (Center for Clean Air Policy 1998).

Table 6 provides summaries of the estimated costs of achieving a 90 percent reduction in electric power mercury emissions. Estimated annualized costs of implementing mercury MACT range from approximately $1.83 billion to $6.08 billion per year. The high estimates are based on the EPA's initial examination of a reduction in mercury emissions (U.S. Environmental Protection Agency 1997a), and the low estimates are from the EPA's most recent analysis (U.S. Environmental Protection Agency 1999a). Implementation of emissions

23 The EPA's Regulatory Determination suggests the agency also would regulate oil-fired units. However, coal-fired generation represents 99 percent of mercury emissions from electric power boilers (U.S. Environmental Protection Agency 2000b).
24 Coal switching costs vary widely depending on the type of coal used. The potential of coal switching will depend on available quantities of coal with low mercury content.
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Table 6. Impact of a Policy to Reduce Mercury from Coal-fired Facilities

<table>
<thead>
<tr>
<th></th>
<th>Coal Impact</th>
<th>Natural Gas Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total Annual Cost ($billion)</td>
<td>Average Cost ($/MWh)</td>
</tr>
<tr>
<td>Mercury MACT</td>
<td>$1.83–$6.08</td>
<td>$0.88–$2.95</td>
</tr>
<tr>
<td>Mercury Trading</td>
<td>$1.40–$2.04</td>
<td>$0.68–$0.99</td>
</tr>
</tbody>
</table>

Policies achieve a 90 percent reduction in coal-fired mercury emissions.

1 Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).
2 Average cost estimates were derived by dividing total costs by estimates of coal-fired generation in 2010 from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).
Source: U.S. Environmental Protection Agency 1997a, U.S. Environmental Protection Agency 1999a, and NERA calculations.

Trading is projected to lower costs to between $1.40 billion and $2.04 billion (U.S. Environmental Protection Agency 1999a), although it is important to note that development of a MACr program to address mercury emissions likely would prohibit meaningful trading. These latter estimates assume implementation of the NOx SIP Call, which may partially account for the reduction in costs from previous EPA estimates.

Implementation of controls on electric utility mercury emissions could lead to shifts in fuel utilization. Table 6 shows that the EPA predicts that implementation of a MACT for mercury would not result in any changes in capacity for either coal or natural gas units but would lead to shifts in generation. Figure 11 shows the predicted changes in generation in 2010. The EPA projects that the mercury MACT would decrease coal-fired generation by 15 billion kilowatt-hours and increase natural gas generation by an equivalent amount (U.S. Environmental Protection Agency 1999a). Implementation of a cap-and-trade program is projected to lead to greater shifts in generation, with coal-fired generation decreasing by 41 billion kilowatt-hours and gas-fired generation increasing by approximately the same amount. Predicted changes in other electricity sources, such as nuclear or renewable power, are not reported.

The impact of mercury controls on fuel use appears to be related to the policies for other emissions, notably SO2 and CO2. When a 50 percent SO2 reduction is implemented along with mercury MACT, coal generation is projected to fall by 25 billion kilowatt-hours rather than 15 billion kilowatt-hours for the mercury MACT alone (U.S. Environmental Protection Agency 1999a). In contrast, when carbon reductions are also required, the projected reduction in coal generation from mercury MACT is only 1 billion kilowatt-hours (U.S. Environmental Protection Agency 1990a).
B. Climate Change

Within the past decade, climate change has emerged as a major focus of U.S. and international environmental policy discussions. Many studies have estimated the economic impacts of the Kyoto Protocol, which would commit the U.S. and other developed nations to substantial reductions in CO₂ and other greenhouse gas (GHG) emissions by the 2008–12 time period.

**Kyoto Protocol**

The Kyoto Protocol represents the first international initiative that would create binding GHG targets.

**a. Policy Overview**

In December 1997, representatives of the world's nations gathered in Kyoto, Japan, under the auspices of the Framework Convention on Climate Change. The Third Conference of the Parties (COP3) produced the Kyoto Protocol. The provisions of the Kyoto Protocol are summarized as follows:
Part III  •  Impact of Regulatory Initiatives on Electricity Fuel Use

- Industrialized nations, the so-called “Annex I” parties, agreed to reduce their emissions of six greenhouse gases by about 5 percent, on average, between 2008 and 2012, relative to 1990 levels. Different national emission targets were set. The U.S. target is a 7 percent reduction relative to 1990 levels.

- Trading of national emission rights (targets) among Annex I countries is allowed, as is project-by-project bilateral exchange of credits (joint implementation) among Annex I countries.

- Annex I countries can receive credits for reductions accomplished in non-Annex I countries (developing countries), using the Clean Development Mechanism (CDM).

- Banking of emission credits to subsequent periods is allowed, (i.e., between the 2008 to 2012 compliance period and subsequent periods) but targets for periods beyond 2012 are not specified.

- Nations are given sovereignty in selecting domestic policy instruments to achieve the national targets.

- Provisions are made to include “sinks” (i.e., carbon sequestration) in the calculation of compliance with targets.

- The Protocol enters into force only when it is ratified by 55 nations, as long as those countries include Annex I countries representing at least 55 percent of 1990 Annex I CO₂ emissions.

International developments are proceeding to complete elements of the Kyoto Protocol. In November 1998, during the Fourth Conference of the Parties (COP4) in Buenos Aires, Argentina, delegates developed a work plan for the following two years, including schedules for concurrent development of rules for international trading, joint implementation, and CDM. In October and November of 1999, the Fifth Conference of Parties (COP5) met in Bonn, Germany, and continued work to develop the rules and procedures to implement the Protocol.

Although a total of 83 countries and the European Union have signed the treaty, only 29 countries—all developing nations—have ratified the Protocol. The U.S. has signed the treaty, but has not committed to ratifying the Kyoto Protocol. In fact, the U.S. Senate, by a vote of 95–0, is on record that it will not provide its advice and consent to the Protocol unless: (1) the Protocol also mandates specific commitments to limit or reduce GHG emissions in the same compliance period by developing countries; (2) the Protocol does no serious harm to the U.S. economy (U.S. Senate 1997). President Clinton has indicated that he will not submit the treaty to the Senate absent these conditions (Tebo 1998). Implementation of the Kyoto Protocol, therefore, is clearly speculative. Assessing the impacts of the Kyoto Protocol, however, is useful to illustrate the implications of limits on GHG emissions.
b. Policy Impact

Virtually every study indicates that implementation of the Kyoto Protocol in the U.S. could result in a major shift in the electric generation fuel mix. The impact of the Kyoto Protocol in the U.S. also depends substantially on the availability (and price) of international CO₂ credits. As noted, the Kyoto Protocol allows for several trading mechanisms designed to reduce the global cost of meeting the targets. As many studies have indicated, the global cost of meeting Kyoto targets would be substantially reduced if the U.S. and other Annex I nations could take advantage of relatively cheap emission reductions in developing countries (see, e.g., Weyant and Hill 1999, Toman et al. 1999). With the exception of the CDM, however, the programs only allow trading among Annex I countries. In addition, as numerous authors have noted, many hurdles would have to be overcome before full international trading could be implemented successfully (e.g., Harrison 1997, Kopp et al. 1998).

The Energy Information Administration (EIA) has evaluated the following cases regarding CO₂ reductions (U.S. Department of Energy 1998b):

1. *Business-As-Usual (BAU)*—This provides a benchmark, i.e., no domestic CO₂ targets. Under BAU, CO₂ emissions are projected to be 33 percent above 1990 levels in 2010 and 43 percent above 1990 levels in 2020.

2. *Full International Trading*—This case assumes that the U.S. domestic target would be 24 percent above 1990 levels, which implies that the bulk of the required U.S. reduction would be obtained through international CO₂ trading.

3. *Annex I Trading*—This case assumes a domestic target equal to 9 percent above 1990 levels, with Annex I trading being used to obtain the additional credits needed to achieve the Kyoto target.

4. *No Trading*—This case assumes that the entire U.S. target would have to be achieved by domestic CO₂ reductions. In this case, the domestic CO₂ target is assumed to be 3 percent below 1990 levels. (The remainder of the Kyoto requirement that U.S. carbon emissions be 7 percent below 1990 levels is assumed to be achieved by decreases on other GHG emissions and increases in carbon sinks.)

Figures 12 and 13 report EIA results on the impact of the Kyoto Protocol based upon the Annex I trading case. As discussed below, the other assumptions regarding international trading lead to very different results. The two figures show the fuel mix, under BAU and Kyoto, in 2010 and 2020, respectively.

Figure 14 shows historical trends in fuel mix and fuel mix projections based upon implementation of the Kyoto Protocol, combined with NOₓ and SO₂ policies, as evaluated by the Electric Power Research Institute (Electric Power Research Institute 2000). The results are similar to the EIA results.

These results indicate that implementation of the Kyoto requirements in the U.S.—Under the assumption of Annex I trading—would lead to dramatic shifts in the electric power generation fuel mix, particularly by 2020. The shifts include:

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Figure 12. Electric Generation Fuel Mix in 2010, Business-As-Usual and Kyoto

Electrical Fuel Mix (Percent of kWh)

- **Business-As-Usual**
  - 10% Coal
  - 34% Oil
  - 30% Gas
  - 1% Nuclear
  - 26% Hydro + Non-Hydro Renewables

- **Kyoto**
  - 11% Coal
  - 26% Oil
  - 17% Gas
  - 45% Nuclear
  - 1% Hydro + Non-Hydro Renewables


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Figure 13. Electric Generation Fuel Mix in 2020, Business-As-Usual and Kyoto

Electrical Fuel Mix (Percent of kWh)

- **Business-As-Usual**
  - 9% Coal
  - 8% Oil
  - 34% Gas
  - 1% Nuclear
  - 48% Hydro + Non-Hydro Renewables

- **Kyoto**
  - 15% Coal
  - 13% Oil
  - 13% Gas
  - 2% Nuclear
  - 58% Hydro + Non-Hydro Renewables

The Kyoto case assumes U.S. domestic CO₂ target equal to 1990 + 9 percent (Annex I Trading).

42. Fueling Electricity Growth for a Growing Economy

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Figure 15. U.S. Electric Generation Fuel Mix under Different Kyoto Trading Cases, 2010

![Bar chart showing fuel mix for different trading cases in 2010.]


Figure 16. U.S. Electric Generation Fuel Mix under Different Kyoto Trading Cases, 2020

![Bar chart showing fuel mix for different trading cases in 2020.]


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DOE002-0661

Obtained and made public by the Natural Resources Defense Council, March/April 2002
• The natural gas percent in 2020 for Kyoto ranges from 60 percent under No Trading to 47 percent under Full International Trading.

• The nuclear percent in 2020 for Kyoto ranges from 15 percent under No Trading to 11 percent under Full International Trading.

• The renewables percent in 2020 for Kyoto ranges from 20 percent under No Trading to 11 percent under Full International Trading.

As these results show, full international trading would substantially reduce the economic impact of the Kyoto Protocol on the U.S. electricity system. As shown in the Appendix, similar shifts in the electric power fuel mix due to the Kyoto Protocol are predicted by other studies.

In addition to inducing large shifts in the electricity generation mix, implementation of the Kyoto Protocol could lead to substantial increases in electricity costs and rates. Interactions with other regulatory initiatives may lead to additional costs not accounted for by analyses focusing solely on climate change policies. A recent EPRI study, for example, suggests that the relative time tables for implementing the NOx SIP Call and Kyoto Protocol would lead to premature retirement or reduced utilization of electricity generation units with NOx control investments (Electric Power Research Institute 2000). Under the current NOx SIP Call, NOx pollution control investments would need to be made by 2003. These investments would be made obsolete if the Kyoto Protocol were implemented—only four to five years after the NOx SIP Call—because CO2 reductions would lead to collateral reductions in NOx emissions. Figure 17 shows the electric unit capacity for which emission control investments are projected over the period 2000 to 2012 as well as the eventual utilization of the units over the period 2018 to 2020. The figure also lists the amounts of the overall investments in NOx and SOx controls for the various cases. In the BAU case, most of the units represented in the $11.6 billion investment in NOx and SOx control necessary to meet NOx SIP Call and Title IV (Phase II) SOx requirements would still be operating in the 2018 to 2020 period. In contrast, if the SOx and CO2 initiatives were put in place, relatively little of the $3.0 billion investment in NOx pollution control would be operating in the 2018 to 2020 period. No additional investment in SOx is necessary under the Kyoto targets due to collateral SOx reductions from CO2 policies.

Figure 18 shows EIA estimates of the electricity rate effects of the Kyoto Protocol in 2005, 2010, and 2020. (These results assume Annex I trading, i.e., a domestic U.S. CO2 target equal to 9 percent above 1990 level.) Compliance with Kyoto would raise the electricity price in 2010, for example, by 3.0 cents per kilowatt-hour from 6.0 cents per kilowatt-hour to 9.0 cents per kilowatt-hour, an increase of 50 percent. The rate effects of the Kyoto Protocol would be substantially different under other assumptions regarding international GHG trading. The EIA estimates that the impact of the Kyoto Protocol on 2020 electricity prices would be 1.7 cents per kilowatt-hour under full international trading, and 3.4 cents per kilowatt-hour under no international trading.

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Figure 17. Amount and Fate of Emission Control Retrofits for SO₂ and NOₓ Cap
Compliance under CO₂, SO₂, and NOₓ Policies and Business-As-Usual

![Diagram showing capital costs for SO₂ and NOₓ control retrofits for different scenarios.]

All but 6-10 GW of capacity is at coal-fired units. All scenarios include the NOₓ SIP Call. The Current Policy Direction also includes the Kyoto Protocol (U.S. domestic emissions at 1990 + 9 percent levels with Annex I trading), the NOₓ SIP Call, and a 50 percent reduction in SO₂ from Title IV Phase II levels. The “2030 Carbon Glide Path” uses more gradual CO₂ emission reductions while maintaining the same cumulative CO₂ emissions as the Current Policy Direction.


The Appendix to this report provides additional information on the impact of the Kyoto Protocol on the electric utility sector and other economic conditions. The following areas are discussed:

1. Fuel utilization;
2. Energy prices and expenditures;
3. Overall U.S. economic performance; and
4. Regional economic differences.

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C. Water Quality

Regulations related to water quality can have substantial impacts on individual electric power facilities. This section considers the impacts of three water quality programs:

1. Water Quality Standards and Criteria Development and Implementation;
2. Total Maximum Daily Loads (TMDLs); and
3. Requirements related to Cooling Water Intake Structures (CWIS).

1. Water Quality Standards, Criteria Development, and Implementation

The Federal Water Pollution Control Act (known as the Clean Water Act) is the primary means for regulating surface water pollution in the U.S. The Clean Water Act (CWA) requires that virtually all entities obtain a permit before discharging pollutants into navigable waters from a specific source. The permit program, or National Permit Discharge Elimination System (NPDES) program regulates discharges of pollutants into surface waters. The CWA allows states to manage this program, if approved by EPA. The resulting NPDES permitting program bases its limits on industry-specific effluent guidelines and the development and implementation of water quality standards developed by each state.
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2. Policy Overview

In issuing NPDES permits, the appropriate regulatory authority is required to impose effluent discharge limitations necessary to ensure state water quality standards are maintained. Water quality standards consist of two parts. First, states must designate certain beneficial “uses” for each water body. Second, regulators must develop water quality “criteria” necessary to protect the beneficial uses. (These criteria include maximum concentrations of water pollutants.) Therefore, water quality standards serve two purposes. They establish the water goals for a specific waterbody, and they serve as the basis for water quality-based treatment controls and strategies beyond the minimum technology-based levels of treatment.

Since the passage of the CWA, many refinements have been made to the supporting documentation defining the fundamental components of water quality criteria. In addition, amendments to the CWA and regional initiatives have pushed the boundaries of “water quality–based permitting.” They have added significant complexity to issues such as the limits of analytical methods, definition and measurement methods for concepts such as “toxicity” and “bioaccumulation factor,” and improved knowledge on the fate and transport of particular pollutants. These refinements have had the effect of refocusing the permitting program from a technology-based program to a more sophisticated program based on water quality, a program which could be more difficult to assess and administer.

b. Policy Impact

These changes mean that point source dischargers now are faced with more restrictive effluent limitations in their permits. More pollutants will be addressed, lower limits will be required, and mechanisms for flexibility in meeting these limits will be reduced. This increases the cost of compliance, the administrative costs of assuring that compliance, and the legal costs associated with permit negotiations. These increased costs could affect fuel choice and energy prices and could raise energy supply concerns.

2. Total Maximum Daily Load Program

A major component in future water quality–based permit limitations will be the Total Maximum Daily Load (TMDL) program. A TMDL is the amount of a pollutant a water body can assimilate and still maintain applicable standards. To ensure that water quality standards are attained, TMDLs can result in effluent standards that are more stringent than technology-based standards for specific individual sources, categories of point sources, or non-point sources. TMDLs must be developed for all individual pollutants that may adversely affect the attainment of water quality standards.

a. Policy Overview

The TMDL process is mandated by the CWA to address situations involving water bodies that do not currently meet applicable water quality standards. The CWA creates a mechanism for the review of water quality limited water bodies to determine whether more stringent permit conditions may be required. The TMDL process establishes a link between individual water body water quality assessments and water quality–based permit actions.