United States General Accounting Office

GAO

Report to Congressional Requesters

October 2002

AIR POLLUTION

Meeting Future Electricity Demand Will Increase Emissions of Some Harmful Substances

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GAO-03-49

October 2002

AIR POLLUTION

Meeting Future Electricity Demand Will Increase Emissions of Some Harmful Substances

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Highlights

Highlights of GAO-03-49, a report to the Chairmen of the Senate Committee on Environment and Public Works and its Subcommittee on Clean Air, Wetlands, and Climate Change

Why GAO Did This Study

Electric power plants burn fuels that can produce harmful emissions, such as carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide, which can pose human health and environmental risks. To assess the potential risks of meeting future electricity demand, congressional committees asked GAO to (1) report on the Energy Information Administration's (EIA's) national and regional projections of such emissions by 2020, and (2) determine how the projections would change using alternative assumptions about future economic growth and other factors that advisers in these fields recommended. GAO also assessed the potential effects of future electricity demand on water demand and supply.

What GAO Recommends

GAO recommends that the Administrator, EIA, work with EPA and states to ensure that EIA incorporates into its modeling of electricity generation and emissions the most current information on regulatory limits for certain emissions, such as nitrogen oxides.

www.gao.gov/cgi-bin/getrpt?GAO-03-49

To view the full report, including the scope and methodology, click on the link above. For more information, contact John B. Stephenson at (202) 512-6225 or stephensonj@gao.gov.

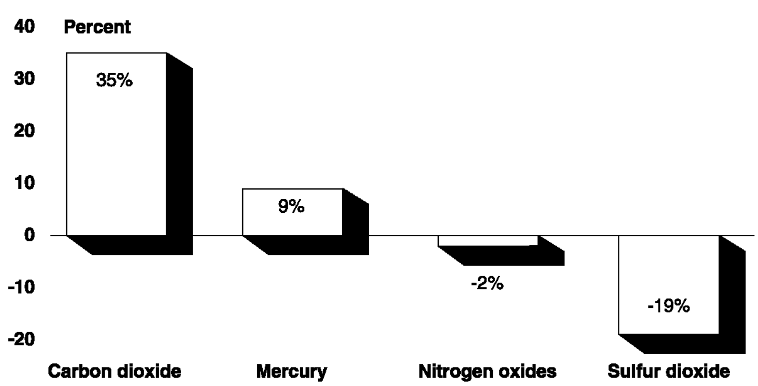
What GAO Found

EIA forecasts that as electricity generation increases 42 percent by 2020, power plants' annual carbon dioxide and mercury emissions will rise nationwide by about 800 million tons and 4 tons, respectively. At the same time, EIA expects plants' annual emissions of nitrogen oxides and sulfur dioxide to decrease nationwide by about 100 thousand tons and about 2 million tons, respectively. Regionally, EIA forecasts that emissions of nitrogen oxides and sulfur dioxide will increase in some areas of the country; mercury will also increase in some areas, while carbon dioxide will increase in all areas.

EIA also estimated emissions from three additional scenarios, using different assumptions based on recommendations from advisers GAO consulted. Like EIA's original forecast, the scenarios showed an increase nationwide in power plants' annual carbon dioxide and mercury emissions and a decrease in emissions of nitrogen oxides and sulfur dioxide between 2000 and 2020, although at different rates than EIA's projections. However, the scenarios also showed that, regionally, emissions of nitrogen oxides and sulfur dioxide could rise in some areas. Separately, GAO found that EIA had not used the most current data on certain emissions limits in its model, although this had a limited impact on the forecasts.

GAO estimates that power plants will use between 3 percent less and 17 percent more water by 2020, although they will use less water for each unit of electricity produced than they currently do, primarily because of new technologies that require less water. The total increase in water use is not likely to create shortages, but it could affect companies' decisions about where to locate new plants and what type to build.

EIA's Projected Changes in Harmful Air Emissions from Power Plants by 2020



Source: GAO analysis of EIA data.

EIA forecasts nationwide increases in power plants' carbon dioxide and mercury emissions and decreases in their emissions of nitrogen oxides and sulfur dioxide by 2020.

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Abbreviations

EIA	Energy Information Administration
EPA	Environmental Protection Agency
USGS	U. S. Geological Survey
SIP	State Implementation Plan

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United States General Accounting Office
Washington, DC 20548

October 30, 2002

The Honorable James M. Jeffords
Chairman, Committee on Environment
and Public Works
United States Senate

The Honorable Joseph I. Lieberman
Chairman, Subcommittee on Clean Air,
Wetlands, and Climate Change
Committee on Environment and Public Works
United States Senate

Electricity is critical to the nation's economy. To generate electricity, power plants use a variety of fuels, including fossil fuels—coal, natural gas, and oil, which account for about two-thirds of the electricity—and nuclear fuels as well as other sources. As a result of the combustion process, power plants emit an array of harmful substances, such as carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide, which pose human health and environmental risks, especially if the plants do not take steps to reduce their emissions. For example, carbon dioxide emissions have been linked to global climate change, among other effects, and exposure to mercury can lead to nervous system disorders and birth defects. Although regulations have been implemented to restrict the emission of nitrogen oxides and sulfur dioxide, and some power plants have installed equipment to reduce emissions of these substances, these emissions still contribute to public health problems, including respiratory illnesses and premature death as well as environmental problems such as acid rain and smog.

Environmental Protection Agency (EPA) data show that, in 1999, power plants were the single greatest industrial source of all four substances, emitting 35 percent of the nation's carbon dioxide, 37 percent of its mercury, 23 percent of its nitrogen oxides, and 67 percent of its sulfur dioxide. As demand for electricity grows, companies not only will build new power plants, but will also continue operating existing plants. Some of the older existing plants do not have to meet the emission standards that new plants must meet. As a result, older plants generally emit more pollution per unit of electricity generated than newer plants.

Forecasts of future electricity supply and demand and associated air emissions are used to develop national energy and environmental policies, among other things. The Energy Information Administration (EIA) within the Department of Energy uses the National Energy Modeling System, a computer-based modeling system to forecast annually future energy supply, demand, and prices over a 20-year period. EIA's forecasts depend on the specific assumptions used in the model, such as economic growth and world oil prices. EIA develops a "reference case" forecast, which uses assumptions and data on known technology, demographic and other trends and current laws and regulations, including those that limit emissions. It also develops several alternative forecasts, which it bases on assumptions of both higher and lower oil prices and economic growth, among other factors.

Because the Congress is considering various proposals for a future energy policy, you asked us to (1) report on EIA's overall and region-specific projections of emissions of carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide from electricity-generating facilities in 2020, and (2) determine how the emissions projections in EIA's reference case would change using alternative assumptions about key variables, such as economic growth and fuel prices, based on suggestions by expert advisers we contacted. In addition, because power plants use large amounts of water during the process of generating electricity, you asked us to determine how future electricity demand might affect future water demand and supply.

To address these issues, we analyzed EIA's reference case forecast of future electricity demand and associated air emissions contained in its *Annual Energy Outlook 2002* and supporting studies. Our analysis focused on EIA's estimates of electricity and emissions from electric utility power plants and excludes industrial and other facilities that produce electricity as a by-product of their operations, which they then sell to utilities for distribution. To advise us in our analysis, we contacted a wide range of individuals with experience in modeling electricity generation and its environmental effects, including staff of EPA and the Department of Energy, and representatives of environmental organizations, consulting firms, research and academic institutions, and the electric generation industry (see app. I). We asked these individuals, who were most frequently identified by their peers as knowledgeable in a particular field, to review EIA's model and supporting documentation and suggest any alternative assumptions, such as the rate of future economic growth or fuel price increases, that they thought were more likely than those included in EIA's reference case, based on their expertise in energy modeling and related topics. We selected EIA's reference case because, according to EIA, it presents a "business-as-usual" forecast, based on known technology, demographic and other trends, and current laws and regulations. We then asked EIA to rerun its model substituting alternative assumptions based on the advisers' suggestions and analyzed the results. We did not attempt to evaluate EIA's model or determine which set of assumptions was the most likely to occur. Finally, we obtained and analyzed data on power plants' water use and developed estimates of future water demand based on EIA's forecasts of electricity production. Our review was conducted from October 2001 through October 2002 in accordance with generally accepted government auditing standards. Appendix I contains additional information regarding our methodology.

Results in Brief

EIA's reference case shows that electricity generation will increase overall by 42 percent from 2000 through 2020 and that power plants will emit 800 million tons (or 35 percent) more carbon dioxide and 4 tons (or 9 percent) more mercury per year by 2020 than they did in 2000. This anticipated increase in emissions would result from power plants' increased use of fossil fuels to meet anticipated demand and the general absence of federal or state regulations establishing emissions standards for carbon dioxide and mercury from power plants. The projected mercury emissions could decrease, however, once EPA proposes mercury limits, which are required by 2004. In contrast, EIA forecasts that by 2020 power plants' total emissions of nitrogen oxides and sulfur dioxide will decrease nationwide by about 100 thousand tons (2 percent) and about 2 million tons (19 percent), respectively. This expected decline in emissions results from the anticipated need for power plants to meet projected increases in electricity demand while complying with clean air regulations. This will necessitate building new plants that emit relatively lower levels of these pollutants and installing emissions controls at some existing plants. Such practices would coincidentally reduce mercury emissions, explaining in part why EIA's model projects a smaller increase in emissions of mercury than carbon dioxide. Despite these overall declines, EIA forecasts that emissions of nitrogen oxides and sulfur dioxide will increase in some regions of the country. Such regional increases may complicate efforts to improve air quality and curb acid rain in the areas where pollutants are emitted as well as in adjacent areas where they may spread via wind currents. EIA forecasts that mercury emissions may increase in some areas and decrease in others, depending on the amount of coal used, while carbon dioxide emissions will increase nationwide.

EIA modeled three additional cases using alternative assumptions that adjusted the model's values for electricity demand and natural gas prices to address uncertainties identified by our advisers. Like the reference case, these alternatives showed that, from 2000 through 2020, annual carbon dioxide and mercury emissions from power plants would rise in all cases, although at different rates than EIA's reference case. EIA's modeling also showed that emissions of nitrogen oxides and sulfur dioxide would decrease under all alternatives. Specifically, the modeling showed that

- carbon dioxide emissions could increase between 659 million tons (28 percent) and 1,129 million tons (48 percent);
- mercury emissions could increase between 5,700 pounds (7 percent) and 17,000 pounds (21 percent);
- emissions of nitrogen oxides could decrease between 41 thousand tons (1 percent) and 204 thousand tons (5 percent); and
- sulfur dioxide emissions could decrease about 2.1 million tons (19 percent) under all three alternatives, because federal emissions limits apply under all alternatives.

The modeling also showed that emissions of nitrogen oxides and sulfur dioxide could increase in some areas, despite the projected decreases nationwide. Separately, in working with EIA's model we found that the agency had not used the most current data on certain emissions limits, although this had a limited impact on the emissions forecasts. We are making a recommendation to the Administrator of EIA to update these data in the model.

Depending on the type of technology installed, as power plants increase production to meet EIA's forecast electricity demand, we estimate that they will use a total of between 3 percent less and 17 percent more water per year by 2020. However, we also estimate that they will use less water for each unit of electricity produced than they currently do primarily because some will install new technologies that require less water. The future water use is not likely to pose shortages for most areas because state and local authorities must ensure that communities will have an adequate water supply before approving new power plants. Nevertheless, future water use could have some impact on companies' decisions about where to locate new plants and what type to build. For example, when deciding whether it is economically feasible to build a new plant in a particular location, developers must consider, among other things, the cost of obtaining the needed water or using alternative technologies that require little water. Such alternatives could increase construction costs and consume 2 percent to 10 percent of the power generated by the plant. Finally, while future water use may not affect a locality's water supply, it may affect the ecosystems that depend on that water. For example, if water discharged from a power plant to a body of water has an elevated temperature, it could potentially harm aquatic organisms and habitats downstream. EPA has developed regulations to address some of these potential effects.

EIA generally agreed with the findings, conclusions, and recommendations of the report, but suggested a number of technical changes, which we have incorporated as appropriate.

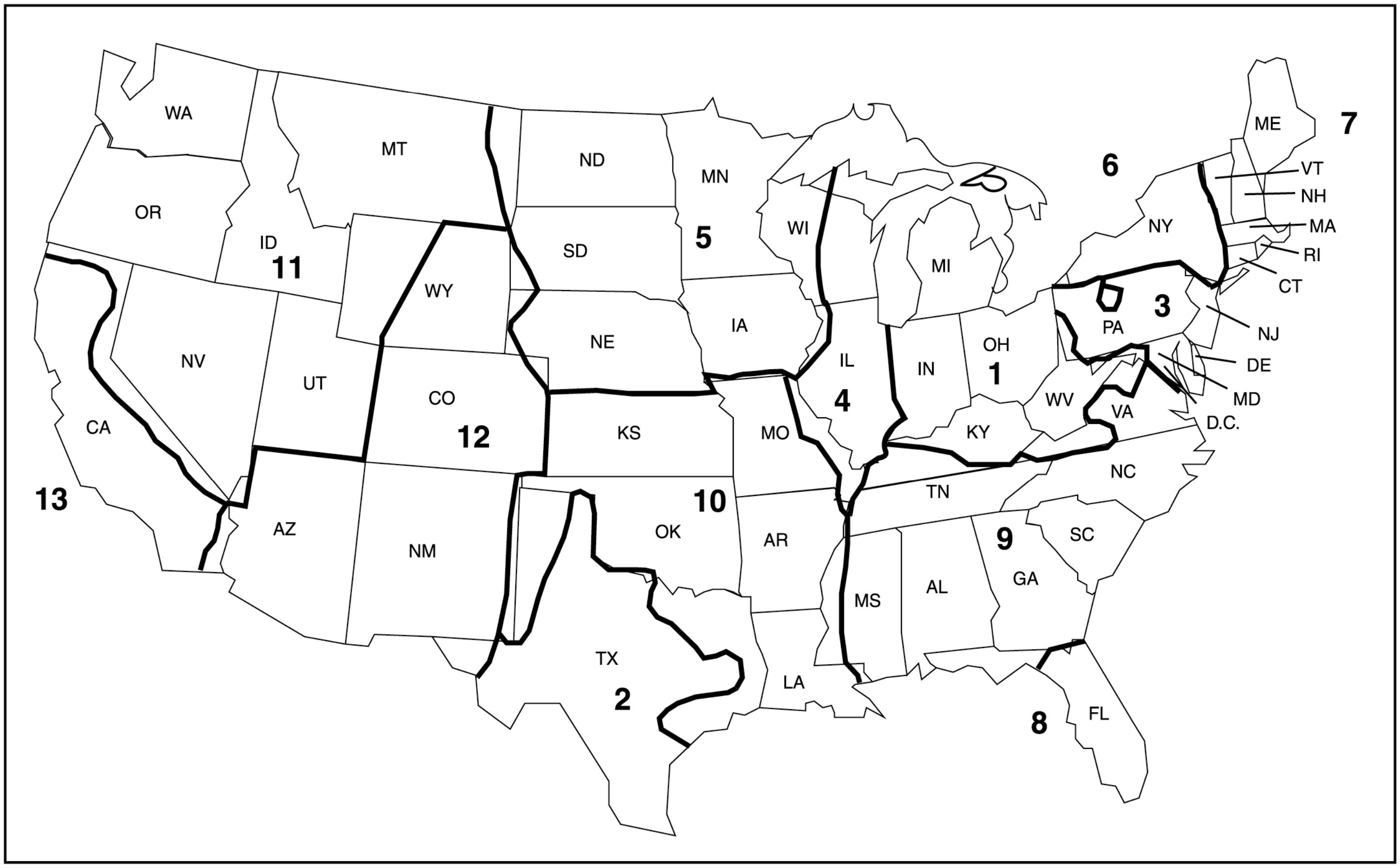
Background

The Department of Energy Organization Act of 1977 requires EIA to prepare annual reports including information on trends and projections for energy use and supply. EIA develops the annual forecasts using the National Energy Modeling System, a computer-based model, and publishes the results in the *Annual Energy Outlook*. Using the model, EIA projects energy supply and demand and air emissions, among other things, over a 20-year period. EIA develops 30 cases with alternative assumptions about economic growth, world oil prices, and electricity demand growth, among other factors, to address the uncertainties inherent in mid- to long-term forecasting. EIA's 2002 projections are based on federal, state, and local laws and regulations in effect on September 1, 2001, and on data current as of July 31, 2001.

EIA forecasts electricity generation and emissions levels for 13 electricity supply regions (see fig. 1).[1]

[1]EIA's electricity supply regions are based on the North American Electricity Reliability Council's (NERC) regional divisions. NERC is a not-for-profit corporation, consisting of members from all segments of the electric industry, including investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal, and provincial utilities; independent power producers; power marketers; and end-use customers.

Figure 1: Electricity Supply Regions Included in EIA's Forecasts



1. **East Central** (East Central Area Reliability Coordination Agreement)
2. **Texas** (Electric Reliability Council of Texas)
3. **Mid-Atlantic** (Mid-Atlantic Area Council)
4. **Western Great Lakes** (Mid-America Interconnected Network)
5. **Upper Midwest** (Mid-Continent Area Power Pool)
6. **New York** (Northeast Power Coordinating Council/ New York)
7. **New England** (Northeast Power Coordinating Council/ New England)
8. **Florida** (Southeastern Electric Reliability Council/ Florida)
9. **Southeast** (Southeastern Electric Reliability Council /excluding Florida)
10. **Lower Midwest** (Southwest Power Pool)
11. **Northwest** (Western Systems Coordinating Council/ Northwest Power Pool Area)
12. **Southwest** (Western Systems Coordinating Council/ Rocky Mountain Power Area)
13. **California** (Western Systems Coordinating Council/ California-Southern Nevada Power)

Source: GAO characterization of information from the Energy Information Administration's Office of Integrated Analysis and Forecasting.

EIA's projections of emissions are influenced by existing laws and regulations that address air pollution. For example, to help limit emissions and protect air quality, EPA, under the Clean Air Act, regulates emissions of nitrogen oxides and sulfur dioxide from a variety of sources, including power plants that burn fossil-fuels. Under the Clean Air Act, EPA requires new sources of air pollution within certain industries to meet federal standards. The standards do not apply to older power plants built before August 17, 1971, that have not been modified, although some older plants have taken steps to meet the standards. But, when older plants make "major modifications" that significantly increase their emissions, they must install modern pollution controls under the requirements of a program called New Source Review. EPA currently does not regulate carbon dioxide or mercury emissions from power plants, although it plans to issue mercury regulations in 2004.

Power plants must limit their emissions of nitrogen oxides and sulfur dioxide under the acid rain provisions of the Clean Air Act Amendments of 1990. To achieve reductions in emissions of nitrogen oxides, the provisions allowed companies with multiple power plants to meet the set limits by calculating the average of their total emissions across two or more plants and ensuring that the average did not exceed the limits. This averaging in effect allows some individual power plants to continue emitting at levels above the limits.

In contrast, the provisions directed EPA to reduce emissions of sulfur dioxide from electricity generating units by setting a nationwide limit, known as a "cap," on emissions from all power plants, not by setting limits for individual plants, and establishing an emissions-trading program. Under this program, each plant receives a number of emissions "allowances" which each represent the right to emit one ton of sulfur dioxide. The allowances may be bought, sold, or banked for use in later years, but power plant owners or operators must own enough allowances at the end of each year to cover their annual emissions.

In addition, EPA has established air quality standards for six principal pollutants including nitrogen dioxide (one of the nitrogen oxides), sulfur dioxide, and ground-level ozone.[2] These "national ambient air quality standards" seek to protect public health by limiting the allowable level of these pollutants in the air. To assist in meeting the ozone standard, EPA has issued two related regulations that further limit emissions of nitrogen oxides. In October 1998, EPA issued a final rule requiring certain states to revise their state implementation plan (SIP) measures to impose additional controls on emissions of nitrogen oxides to mitigate ozone transport in the eastern United States.[3] The rule—known as the NOx SIP call—set stringent caps on emissions of nitrogen oxides in 22 midwestern and eastern states (as well as the District of Columbia) during the summer.[4] In January 2000, EPA issued another rule—known as the Section 126 rule—in response to petitions from 8 northeastern states that the emissions of nitrogen oxides from coal-fired power plants in 12 upwind states and the District of Columbia were being transported by wind patterns into their states, complicating their efforts to meet national air quality standards for ground-level ozone. The rule required 392 facilities in the upwind states to reduce annual emissions of nitrogen oxides and established a cap-and-trade program for emissions within each of those states.[5]

Power Plants' Carbon Dioxide and Mercury Emissions Will Increase by 2020

EIA's reference case forecasts that, overall, as generators increase electricity production to meet rising demand over the next two decades, emissions of carbon dioxide and mercury from power plants nationwide will increase, while their emissions of nitrogen oxides and sulfur dioxide will decrease. On a regional basis, EIA forecasts that power plants' emissions of mercury, nitrogen oxides, and sulfur dioxide will increase in some portions of the country and decrease in others. Carbon dioxide emissions will increase in all areas. These variations in emissions may

[2]The other principal pollutants are carbon monoxide, lead, and particulate matter.

[3]Ozone is a regulated pollutant that forms when nitrogen oxides react with volatile organic compounds in the presence of heat and sunlight.

[4]63 Fed. Reg. 57356 (Oct. 27, 1998). The states were: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. The District of Columbia Circuit Court later vacated the NOx SIP call for Georgia, Missouri, and Wisconsin. *Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000).

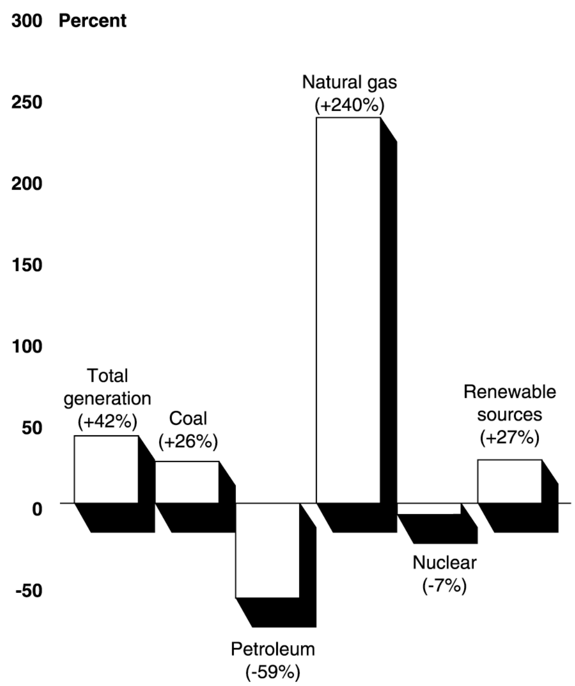
[5]65 Fed. Reg. 2674 (Jan. 18, 2000).

complicate some regions' efforts to control their pollution and reduce the associated risks.

Carbon Dioxide and Mercury Emissions Are Expected to Increase Overall While Nitrogen Oxides and Sulfur Dioxide Decrease

EIA's reference case forecasts that, from 2000 through 2020, electricity generation will increase by 42 percent (see fig. 2), from 3.5 trillion kilowatt hours in 2000 to almost 5 trillion kilowatt hours in 2020. As this figure also shows, the largest increase in electricity generation—240 percent—will come from power plants that burn natural gas.

Figure 2: Projected Changes in Total U.S. Electricity Generation, by Fuel Source, between 2000 and 2020



Note: Renewable sources include, among others, hydropower, solar, and wind energy.

Source: GAO analysis of EIA data.

In response, EIA expects power plants' annual emissions of carbon dioxide to increase nationally by about 800 million tons (35 percent), from 2.4 billion tons in 2000 to 3.2 billion tons in 2020. Similarly, EIA forecasts that plants' annual mercury emissions will increase by about 4 tons (9 percent), from about 40 tons in 2000 to about 44 tons in 2020. EPA plans to issue regulations limiting mercury emissions from power plants in 2004, which could reduce emissions below the projected levels. The expected increase in carbon dioxide and mercury will result primarily from a projected increase in electricity generation from fossil fuels. For example, natural gas and coal emit large amounts of carbon dioxide when burned and coal emits mercury. In addition, these emissions from power plants will increase because there are no federal or state limits on them, with the exception of Maine's mercury emission standard. EIA projects that 88 percent of the 355 gigawatts of new generating capacity needed by 2020 will be fueled by natural gas and another 9 percent by coal.[6] These two fuels are expected to account for 99 percent of the carbon dioxide emissions from all electricity production in 2020. Even though mercury emissions from power plants are not currently federally regulated, they are not expected to increase substantially in the future in part because certain measures that generators take to limit emissions of nitrogen oxides and sulfur dioxide—such as switching to cleaner fuels and installing emissions control technologies—also coincidentally reduce power plants' mercury emissions.

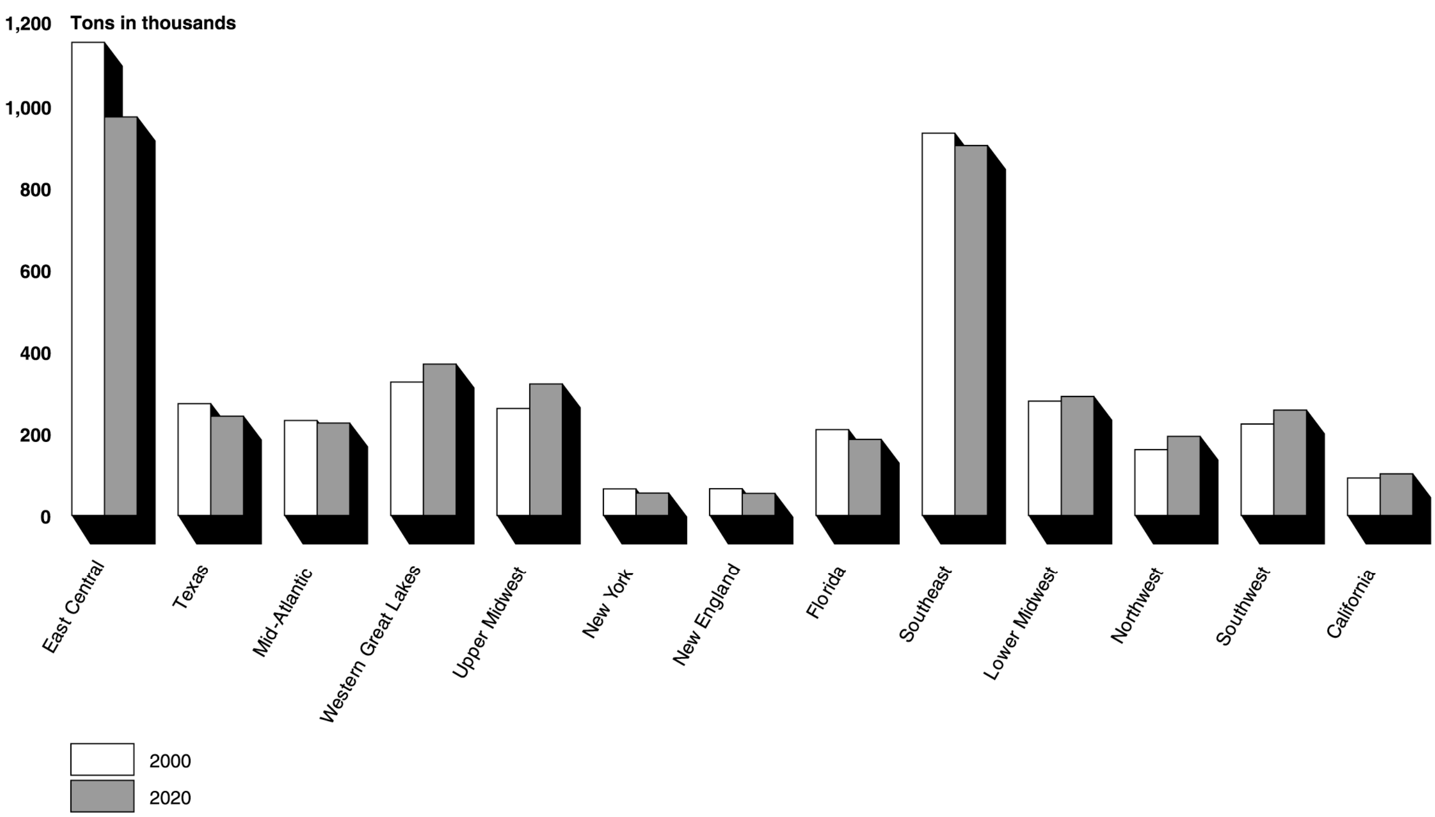
In contrast to the growth of carbon dioxide and mercury emissions, EIA forecasts that, by 2020, power plants' annual emissions of nitrogen oxides will decline from 2000 levels by about 100 thousand tons (2 percent), from about 4.3 million tons to about 4.2 million tons, and sulfur dioxide emissions will decrease by about 2 million tons (19 percent), from 11 million tons to about 9 million tons. Emissions of nitrogen oxides and sulfur dioxide decline, despite increases in electricity generation, primarily because federal and state regulations limit power plants' emissions of these substances. As generators build additional plants and make major modifications to expand capacity at existing plants to meet growing electricity demand over the next 20 years, they must also comply with these limits. To limit emissions from new plants, generators are expected to build both new natural gas- and coal-burning power plants that will include emission control technologies. To limit emissions at some existing plants, generators will continue to switch to cleaner fuels—such as coal that contains less sulfur—and install technologies to control these emissions.

[6]These percentages exclude electricity that is generated by industrial and other facilities that is then sold to electric utilities.

Some Areas of the Country Will Face Increased Emissions

Although EIA forecasts that aggregate annual emissions of nitrogen oxides and sulfur dioxide will decrease nationally by 2020, it projects that emissions of both of these pollutants will increase in some regions of the country and decrease in others. For example, EIA expects emissions of nitrogen oxides to decrease in 7 of the 13 electricity supply regions (see fig. 3).

Figure 3: Electricity Generators' Projected Annual Emissions of Nitrogen Oxides in 2000 and 2020, by Region



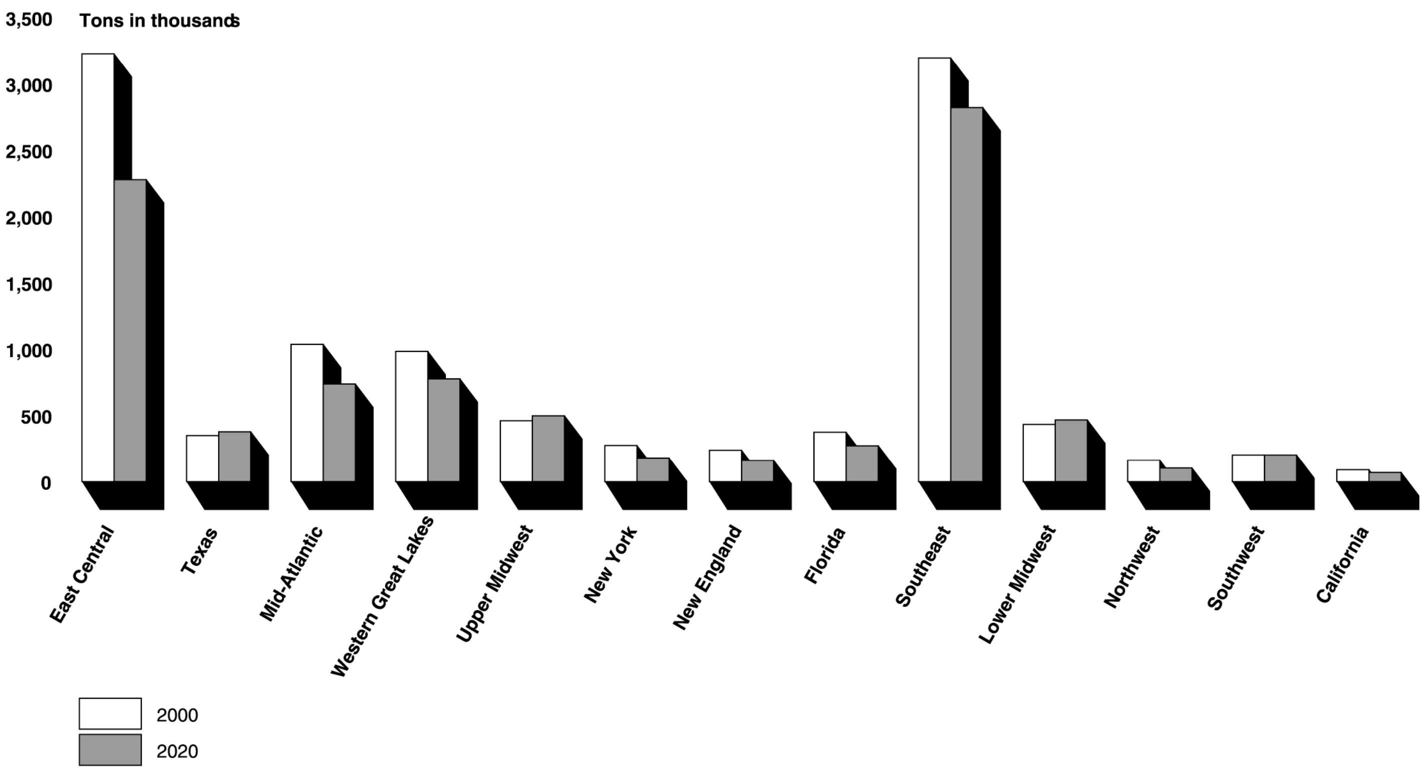
Source: GAO analysis of EIA data.

EIA expects power plants in the Mid-Atlantic area of the United States to experience the smallest decrease in annual emissions of nitrogen oxides—6 thousand tons, or 3 percent—and plants in the East Central area to experience the largest decrease—182 thousand tons, or 16 percent. However, EIA projects that emissions of nitrogen oxides will increase in 6 regions

- California (10 thousand tons, or 11 percent);
- the Lower Midwest (11 thousand tons, or 4 percent);
- the Northwest (32 thousand tons, or 20 percent);
- the Southwest (34 thousand tons, or 15 percent);
- the Western Great Lakes (44 thousand tons, or 13 percent); and
- the Upper Midwest (60 thousand tons, or 23 percent).

Similarly, EIA projects that annual sulfur dioxide emissions from power plants will decline in 10 of the 13 regions by 2020 (see fig. 4).

Figure 4: Electricity Generators' Projected Annual Sulfur Dioxide Emissions in 2000 and 2020, by Region



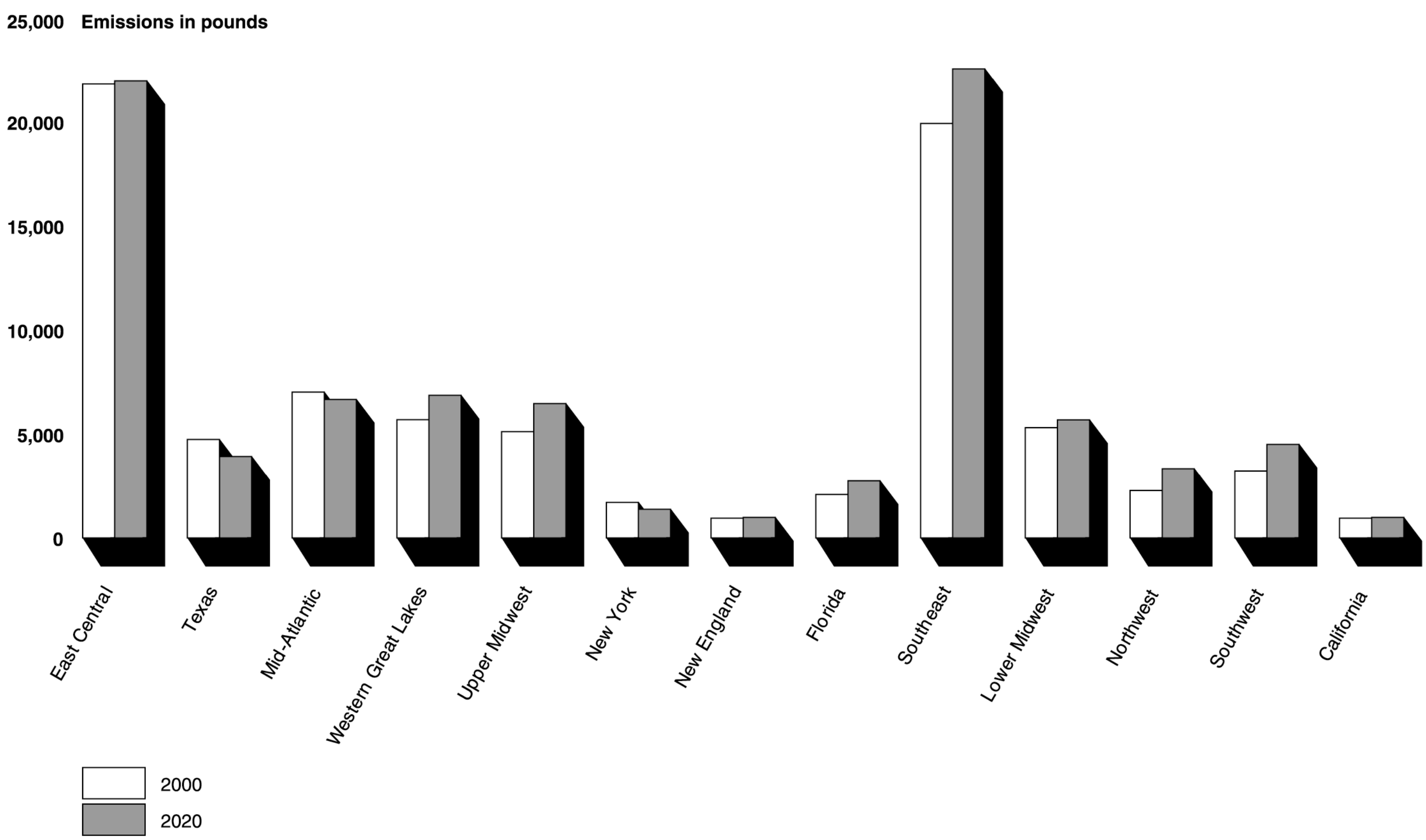
Source: GAO analysis of EIA data.

The smallest decrease—1 thousand tons (under 1 percent)—is expected to occur in the Southwest and the largest decrease—950 thousand tons (29 percent)—is expected in the East Central area of the country. However, power plants' annual emissions of sulfur dioxide are expected to increase in three regions

- Texas (28 thousand tons, or 8 percent);
- the Lower Midwest (33 thousand tons, or 8 percent); and
- the Upper Midwest (38 thousand tons, or 8 percent).

According to EIA, decreases in mercury emissions will range from about 335 pounds (20 percent) in the New York State area to about 821 pounds (17 percent) in Texas (see fig. 5).

Figure 5: Electricity Generators' Projected Annual Mercury Emissions in 2000 and 2020, by Region

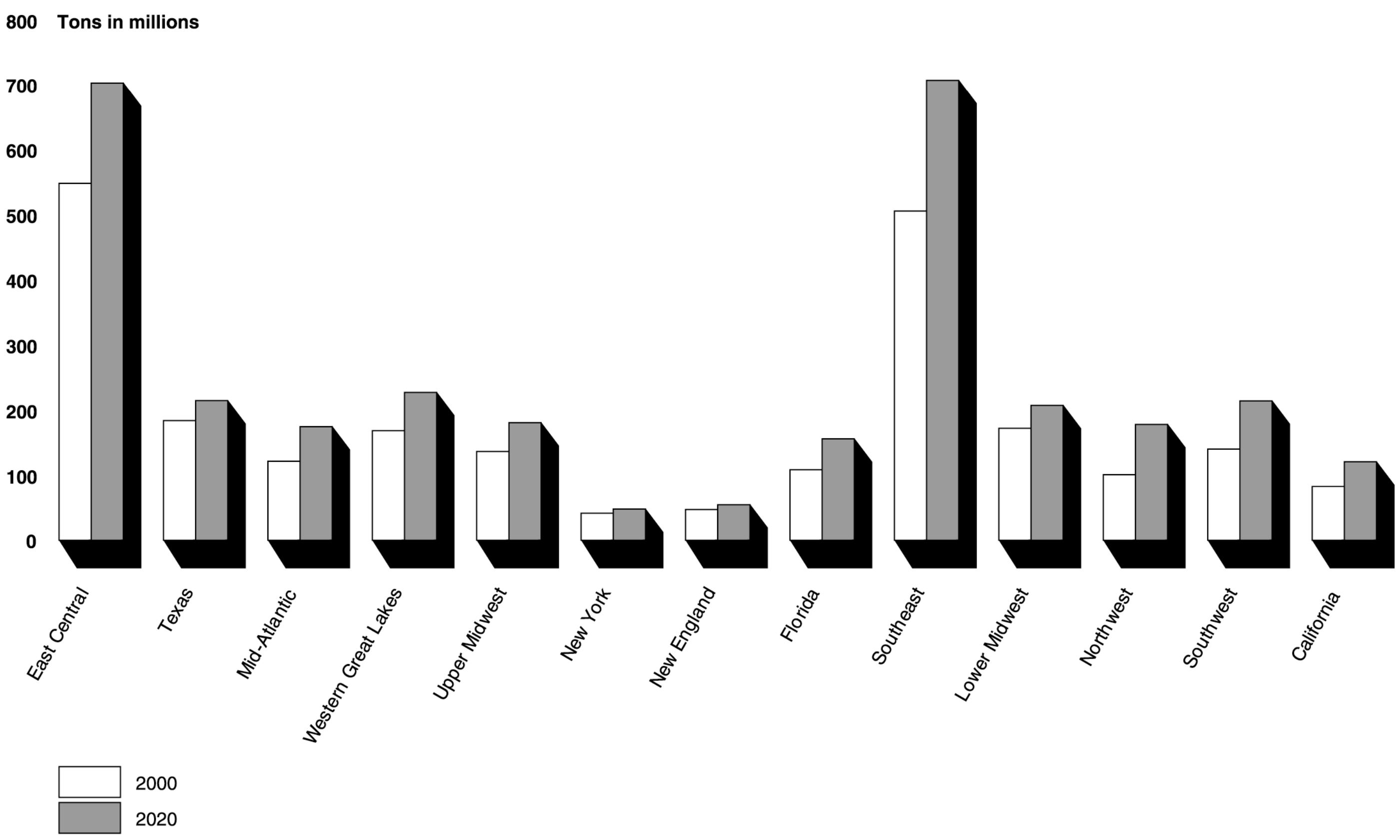


Source: GAO analysis of EIA data.

Furthermore, EIA expects mercury emissions to increase in all but 3 regions, with the smallest increases—about 30 pounds (3 percent)—occurring in New England and California, and the largest increase—about 2,600 pounds (13 percent)—in the Southeast.

In contrast, EIA forecasts that carbon dioxide emissions will increase both nationwide and in all regions (see fig. 6).

Figure 6: Electricity Generators' Projected Annual Carbon Dioxide Emissions in 2000 and 2020, by Region



Source: GAO analysis of EIA data.

EIA projects that increases in carbon dioxide emissions are likely to range from a low of 6 million tons (15 percent) in the New York state area to as much as 200 million tons (40 percent) in the Southeast.

Regional variations in emissions of these four substances result primarily from (1) differences in electricity demand, which largely determines where new generating capacity will be added, and (2) power plants' interactions across regions within the emissions-trading program. As electricity demand increases in one region, generators will expand capacity at existing plants and build additional plants to meet that demand. Consequently, emissions are likely to increase in those regions where capacity is expanded. To comply with federal and state limits on emissions of nitrogen oxides and sulfur dioxide, generators in those regions will, among other things, purchase emissions credits from other plants, some of which may be in other regions, to offset the increases. This typically requires that the plant selling emissions credits either add emissions controls or switch to cleaner fuels, thereby reducing emissions in that region. Accordingly, emissions of nitrogen oxides and sulfur dioxide may increase in the region with the new plants and decrease in the region where emissions credits were purchased. In contrast, because there are no federal or, in most cases, state limits on carbon dioxide or mercury emissions from power plants, these emissions are generally expected to increase, both nationally and regionally, with the expansion of generating capacity. However, plants adding pollution controls to reduce sulfur dioxide and nitrogen oxides in some regions would also remove some mercury as a side benefit, thereby decreasing mercury emissions in those regions.

Alternative Assumptions Lead to Wide-Ranging Estimates of Future Carbon Dioxide and Mercury Emissions

In addition to the alternative cases that EIA runs each year as part of its forecasts, we asked EIA to model three other cases using different values for electricity demand and fuel prices. These cases showed that, between 2000 and 2020, annual carbon dioxide and mercury emissions from power plants would rise under all alternatives, although mercury emissions would decrease in some regions. The modeling showed overall decreases in nitrogen oxides and sulfur dioxide under all alternatives, although these emissions will increase in some regions. Separately, we found that EIA had not used the most current data on certain emissions limits, which would have only a modest impact on estimates.

Most of the Advisers Agreed with EIA's Modeling Methodology but Questioned Electricity Demand and Fuel Price Assumptions

The majority of our advisers described EIA's modeling methodology as sound and suitable for forecasting future electricity generation and emissions, but they did not always agree with EIA's values for two of the key drivers of emissions forecasts—electricity demand and fuel prices. They also said that forecasting is imprecise and that it is difficult to know which modeling assumptions are most appropriate. Some of the advisers provided alternative assumptions, which varied widely, causing most estimates of future emissions to also vary.

EIA's reference case forecasts that electricity demand will increase by an average of 1.8 percent a year between 2000 and 2020. Advisers' alternatives ranged from an annual increase of 1.25 percent (about 31 percent lower than EIA's estimate) to 2.1 percent (about 17 percent higher than EIA).[7] Of the six advisers who provided alternatives, three said that EIA's electricity demand estimates were too high; one agreed with EIA; one said that demand would be equal to or greater than EIA's estimate; and one said that EIA's estimate was too low. Demand could be higher, according to one adviser, if new technologies that use electricity, such as electricity-based transportation, are widely adopted. Another adviser predicted lower increases in demand than EIA and said the actual numbers will depend primarily on energy efficiency policies and economic growth. EIA's analysis of the accuracy of its last 10 annual forecasts found that it underestimated electricity demand 96 percent of the time, with an average error of about 4 percent. Because some air emissions increase with rising electricity demand, underestimating demand can lead EIA's model to underestimate emissions also.

Several advisers raised questions as well about EIA's forecasts of natural gas prices. Two of the advisers said that EIA's methodology overstated the future price of natural gas. Another said prices were too low and that EIA's methodology did not capture the likely volatility in gas prices and future supply constraints that could occur as more gas is used to generate electricity. This expert suggested that EIA perform additional sensitivity analyses to address gas price uncertainties.

EIA's analysis of the accuracy of its past forecasts also indicates that, of all its fuel price forecasts, those for natural gas have been the least accurate, deviating from actual prices by an average of 19 percent in the last ten forecasts, with a tendency to overestimate (58 percent of the time) rather than underestimate (42 percent of the time) prices. According to an EIA official, higher gas prices would make new natural gas plants less economical and could likely lead to the construction of more new coal plants in the future to meet demand for additional electricity generating capacity. This in turn would lead to higher emissions, particularly for carbon dioxide. Therefore, overestimating gas prices could also lead to overestimating emissions.

[7]EIA has developed an alternative case based on an annual electricity demand growth rate of 2.5 percent.

EIA's Model Had Outdated Information on Certain Emissions Limits, Which Had Little Effect on Emissions Projections

Our review of EIA's modeling found that it included outdated information on regulations limiting emissions of nitrogen oxides. EIA used preliminary data on limits for emissions of nitrogen oxides that will take effect in 19 states and the District of Columbia beginning in 2004. As a result, EIA used a 488,000 ton overall limit in its forecast instead of the 473,000 ton final limit, which was published in the *Federal Register*. An EIA official responsible for the model's emissions data said that while they met with industry experts—including EPA staff—in developing their analyses, these final changes were not brought to their attention. According to this official, because of the relatively small change—a 3 percent decline—updating the information would slightly reduce the model's projected emissions of nitrogen oxides. He said EIA would update the information in the model for future forecasts.

In addition, our review of EIA's model found that it included data on the costs and performance characteristics of equipment that power plants use to control nitrogen oxides that were from a 1996 EPA study. An EPA contractor updated this information in 2001 based on information provided by control equipment suppliers and experience gained through more than 200 installations of the equipment. The cost data fell within the ranges reported in similar studies. EIA found that industry groups and experts in the Department of Energy believed that the cost of installing equipment with the performance characteristics described in the study would be higher than reported. As a result, EIA continued using the earlier cost and performance estimates. The EIA official responsible for the model's emissions data said that the agency agrees with EPA's updated performance data but would use higher cost data for future analyses.

Modeling with Revised Electricity Demand and Natural Gas Price Data Leads to Wide-Ranging Estimates of Carbon Dioxide Increases

EIA prepared for us three alternative emissions projections to its reference case by running its model with updated information on pollution control costs and emissions limits as well as revised assumptions to address the electricity demand and fuel price uncertainties identified by the advisers. The first alternative—the "revised reference case"—substituted updated information on limits and costs for controlling emissions of nitrogen oxides. The second alternative—the "high emissions case"—also substituted assumptions about economic growth and technological change that, in turn, increased electricity demand and the price of natural gas. The third alternative—the "low emissions case"—substituted assumptions that lowered electricity demand and natural gas prices.

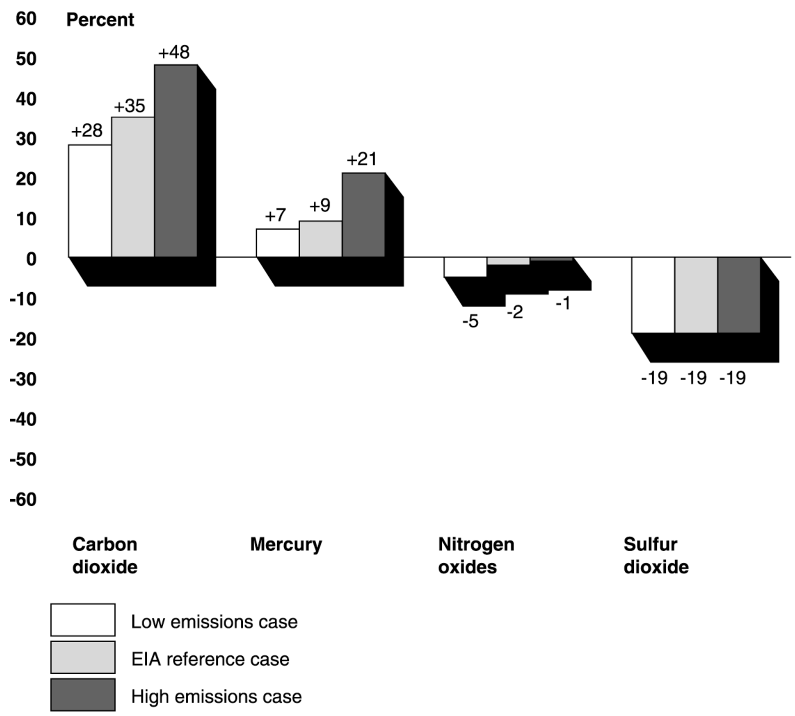
Nationally, these analyses show that increases in carbon dioxide and mercury emissions could vary widely in the future, depending on the assumptions used, while decreases in emissions of nitrogen oxides and sulfur dioxide would be unlikely to vary significantly from EIA's reference case because of regulations that limit these emissions. Specifically, the modeling showed that between 2000 and 2020:

- Carbon dioxide emissions could increase by between 659 million tons (28 percent) in the low emissions case and 1,129 million tons (48 percent) in the high emissions case, compared to 827 million tons (35 percent) in EIA's reference case. The variation from the reference case results from differences in the demand for electricity in each case and the amount of electricity generated from each fossil fuel. Natural gas has about 40 percent less carbon dioxide per unit of energy than coal, so carbon dioxide emissions from natural gas combustion are proportionately lower.
- Mercury emissions could increase by between 5,700 pounds (7 percent) in the low emissions case and 17,000 pounds (21 percent) in the high emissions case, compared to about 7,200 pounds (9 percent) in EIA's reference case. Mercury emissions increase in relation to the amount of electricity generated by coal plants.
- Emissions of nitrogen oxides could decrease by between 41,000 tons (1 percent) in the high emissions case and 204,000 tons (5 percent) in the low emissions case, compared to 104,000 tons (2 percent) in EIA's reference case. The nitrogen oxides estimates do not vary significantly from the reference case due to existing control programs and the fact that new plants are expected to be very clean.
- Sulfur dioxide emissions would decrease by about 2.1 million tons (19 percent) in all cases because the Clean Air Act Amendments of 1990 call for reductions in annual sulfur dioxide emissions from electricity generators.[8]

Figure 7 compares the national results of the low and high emissions cases with EIA's reference case.

[8]The modeling results listed here focus on the low and high emissions cases because the results of the revised reference case did not vary substantially from EIA's reference case.

Figure 7: Percent Changes in Emissions under Three Scenarios, 2000-2020



Source: GAO Analysis of EIA data.

Under all three alternatives, carbon dioxide would increase in all regions but the magnitude of the increases would vary widely. (App. II contains a summary of the regional emissions projections for the reference case and the three alternative cases). For example, annual emissions in the Southeast would increase from about 153 million (30 percent) in the low emissions case to 300 million tons (59 percent) in the high emissions case, while those in New England would increase from about 4 million (9 percent) in the low emissions case to 17 million tons (36 percent) in the high emissions case. For all three alternatives, the Southeast and East Central regions would have the largest emissions increases because these areas are projected to have the largest increases in fossil-fuel generation, while New England and New York would have the smallest emissions increases.

Mercury emissions would increase in 10 of the 13 regions in the revised reference case and the low emissions case, and in 12 of the 13 regions in the high emissions case. The Southeast region has the largest expected increases in emissions and coal-fired generation. Only Texas would have emissions decreases across all three alternatives, ranging from about 1,008 pounds (20 percent) to 1,199 pounds (24 percent).

Even though nationally, emissions of nitrogen oxides would decrease, regionally they would increase in six areas under all three alternatives—California, Lower Midwest, Northwest, Southwest, Upper Midwest, and Western Great Lakes—with the magnitude of the increases varying by region and alternative. The Upper Midwest region would have the largest increase—ranging from about 56,000 tons (22 percent) to 66,000 (25 percent). The alternative modeling showed increased generation from fossil fuels in each of these regions, which may explain the projected emissions increases.

Similarly, while sulfur dioxide emissions are expected to decrease nationally, they would increase in the Lower Midwest and Upper Midwest regions despite the federal limits. Emissions would decrease in 8 of the 13 regions under all 3 alternatives. These trends likely hinge on the national trading program for sulfur dioxide emissions, whereby plants in some regions would control their emissions and sell excess emissions credits to plants in other regions.

EIA has modeled additional cases that project far lower emissions than those presented in its reference case or the three cases EIA prepared for us. For example, for an October 2001 report, EIA modeled a case based on assumptions of policies and programs that would promote clean energy technologies and further reductions in emissions of carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide. This case showed that, by 2020, emissions of carbon dioxide would be 48 percent lower, mercury 90 percent lower, nitrogen oxides 61 percent lower, and sulfur dioxide 76 percent lower than in EIA's reference case.

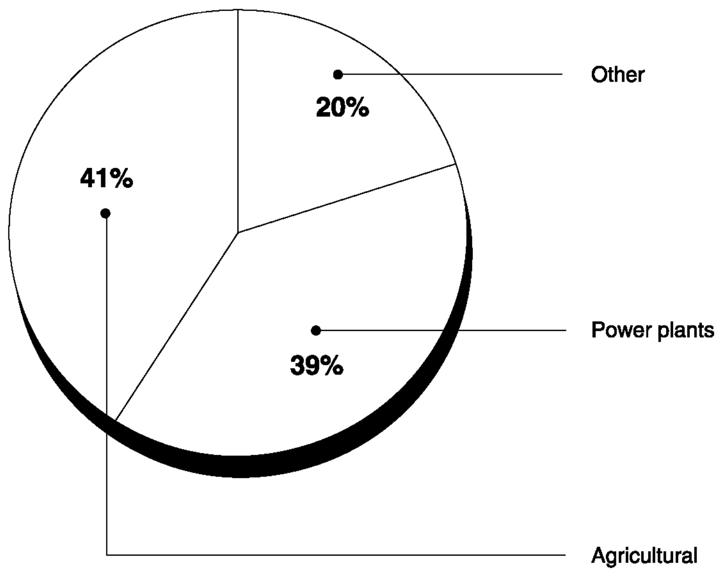
Power Plants' Demand for Water to Meet Future Electricity Needs Should Not Create Shortages, but Could Influence the Location of New Plants

Electricity generation requires more fresh water than all other sectors of the economy except agriculture, according to data from the U.S. Geological Survey (USGS). Power plants' water requirements will likely rise as demand for electricity grows over the next two decades. However, the amount of water needed to generate each unit of electricity would likely decrease because companies are expected to install new technologies that require less water. The total increase in water use is not likely to have an impact on most communities' supplies because state and local authorities protect certain uses, such as for drinking water, when approving the construction of new power plants in their areas. Nevertheless, the increase could influence companies' decisions regarding the locations and types of new plants and may affect aquatic ecosystems.

Overall, Power Plants May Need More Water to Operate in 2020 than 2000, but They Are Expected to Use Less Water per Unit of Electricity Produced

Power plants draw the second largest amount of fresh water from rivers, lakes, and other sources each year—48.2 trillion gallons—according to 1995 USGS data. Only agricultural activities draw more fresh water (see fig. 8).

Figure 8: Activities That Draw Fresh Water from Rivers, Lakes, and Other Sources



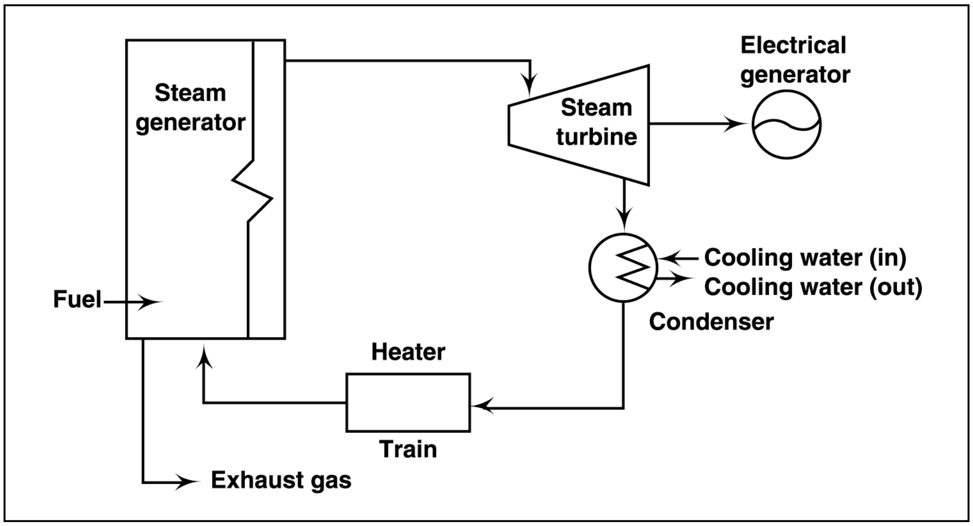
Note: "Other" activities include such uses as domestic, commercial, and mining activities. Percentages are national averages.

Source: USGS, 1995 data are the most current available.

Nationwide, power plants also use five times more fresh water than households use for purposes such as drinking, preparing food, and bathing.

Power plants consume only about 3 percent of the water they draw from a particular source during the process of generating electricity; in contrast, agriculture consumes 61 percent. To generate electricity, most power plants burn a fuel to heat water and create steam (see fig. 9).

Figure 9: Diagram of Electricity Generation by a Steam Turbine

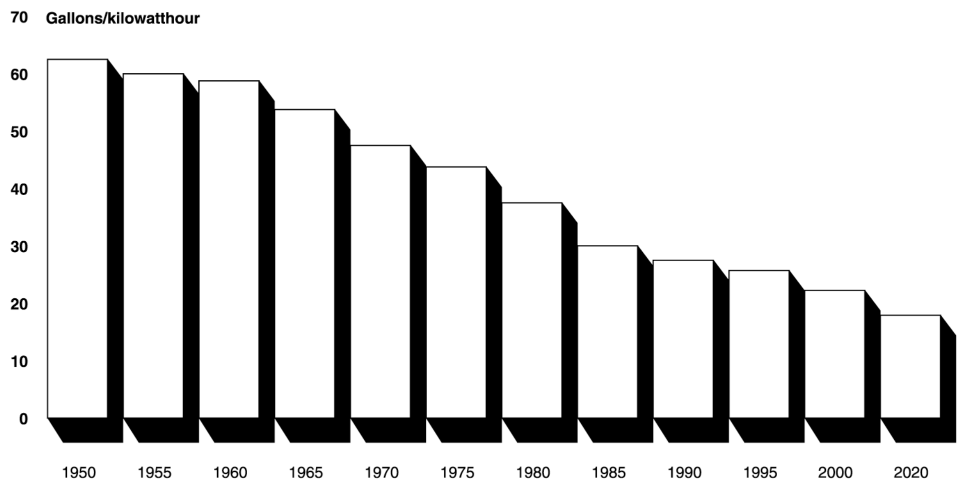


Source: Environmental Protection Agency.

The steam flows through a turbine connected to a generator, which turns the blades and produces electricity. The steam leaving the turbine is carried through pipes, which pass through circulating water. The steam then condenses back into a liquid as the heat is transferred to the water. This water, in turn, flows to a cooling tower, where the heat dissipates through contact with the air, and then recirculates to condense the steam again. This type of system is known as a “wet-cooling” system. Some cooling systems pass the cooling water over the steam pipes once, and then discharge it back to its source or the community’s local sewer system, where the water can be treated and used for other purposes. Such systems draw in 98 percent more water than a recirculating system.

Given these cooling processes, we estimate that power plants will need between 94 billion gallons less water (a reduction of 3 percent) per year by 2020 and 576 billion gallons more water (an increase of 17 percent) to meet EIA’s reference case projections of future electricity demand. The lower estimate assumes all the additional demand is met with a cooling technology that uses significantly less water, and the higher number assumes it is met with recirculating wet-cooling systems. Plants will likely use a combination of the two systems. Regardless, newer technologies will allow plants to consume less water per unit of electricity produced than they currently do. Such reductions in water use would follow a trend that has been underway since the 1950s (see fig. 10).

Figure 10: Water Drawn Into Power Plants for Cooling Per Unit of Electricity Produced, 1950 to 2020



Note: Amounts for 2000 and 2020 are GAO estimates.

Source: GAO analysis of USGS data.

The Potential Need for More Water Should Not Threaten Local Supplies, but Could Affect Where New Plants Are Built

The overall increase in the volume of water used by power plants is unlikely to cause supply shortages for most communities. Companies generally must obtain state and local approval to withdraw water and a permit to discharge it back to the water source or a local sewer system before they can begin construction. In granting the approvals and permits, the water authority usually must ensure that the plants' water use will not adversely diminish regional or local water supplies. To help make this determination, some states are establishing water "budgets" that allocate water resources to ensure supplies for drinking water and other critical activities will remain adequate in the future.

On the other hand, future water use could affect decisions about where to build new plants. When making these decisions, companies must consider whether sufficient water is available at a particular location and whether the cost of withdrawing and discharging the water is prohibitive. Companies consider these costs, along with other important factors—such as the anticipated demand for electricity, the proximity to fuel and transmission lines, and the expected selling price for the electricity—to determine whether building a plant in a particular location would be profitable.

If companies anticipate water supply problems, they may consider using alternative supplies or installing technologies that use less water. For example, 0.5 percent of existing power plants use recycled wastewater, typically in areas where sufficient water supplies are not available. California has begun requiring companies to evaluate the feasibility of using recycled wastewater before approving other water sources. While a viable alternative, there must be sufficiently large quantities of wastewater available to meet the power plant's needs. In addition, plants must treat the wastewater to remove nutrients and minerals that can foul equipment and decrease cooling efficiencies, and these treatment costs add to a plant's operating costs.

Nearly another 2 percent of existing plants have adopted a technology known as "dry" cooling, which uses outside air, rather than water, to cool the steam produced in the plant. Dry-cooling systems can reduce water use by 90 percent to 95 percent compared to wet-cooling systems that use the water only once. However, they can cost 2 to 3 times more to construct than wet recirculating systems. They can also cost significantly more to operate because the fans and other necessary equipment can themselves consume from 2 percent to 10 percent of the electricity generated by the plant. These additional costs can make a dry-cooling system economically infeasible in some locations.

Although plants' future water use may not affect local water supply, it can have ecological effects on the original water sources. For example, pulling water into a plant can kill fish, and discharging water with elevated temperatures back to its source can damage aquatic organisms and habitats. However, EPA has developed regulations for new plants and is developing regulations for existing plants that specify the maximum rates that plants can take water into the cooling system, among other requirements. EPA has also proposed that existing plants upgrade their cooling systems when economically feasible. For example, EPA has proposed that a plant in Massachusetts reduce the amount of heated water discharged by almost 96 percent, or approximately 1 billion gallons per day, in order to lessen the effects on marine life.

Conclusions

EIA's forecasts of the future electricity supply and demand as well as associated air emissions are important for developing national energy and environmental policies. Both the administration and the Congress have often relied on EIA's expertise in modeling and forecasting to assist them in making decisions about such key policies. Most of the advisers whom we consulted agreed that EIA's modeling methodology is sound and suitable for forecasting future electricity generation and emissions. And while the advisers disagreed with some of EIA's values for future electricity demand and fuel price trends, they and EIA recognize that forecasting is imprecise and that it is difficult to determine which modeling assumptions are most appropriate. Nevertheless, regardless of which set of alternatives becomes reality, the modeling shows that the country will face elevated levels of carbon dioxide emissions and potentially mercury emissions. In addition, certain regions of the country will be exposed to higher levels of emissions of nitrogen oxides and sulfur dioxide, even though on a national basis, the levels will decrease. Finally, as EIA continues to assess its modeling accuracy and refine its methodology accordingly, it is important that the agency use the most current data available. This includes data on any federal and state regulations that set limits on emissions, helping to ensure more accurate future estimates.

Recommendations for Executive Action

To ensure that future forecasts of electricity generation and related environmental effects are as accurate and useful as possible, we recommend that the Administrator, EIA, work with EPA and states to ensure that the agency incorporates the most current information on regulatory limits for certain emissions, such as nitrogen oxides, into the modeling of its electricity and emissions projections.

Agency Comments

EIA provided written comments on a draft of this report. These comments are reprinted in appendix III. EIA generally agreed with the findings, conclusions, and recommendations of the report, but believed that there were areas of the draft report that readers might misunderstand without additional information. In this regard, EIA suggested a number of technical changes and clarifications, which we have incorporated as appropriate. Despite general agreement with the report, EIA disagreed with what it characterized as the report's assertion that EIA's projections were based on outdated information on the costs of equipment used to control emissions of nitrogen oxides. However, we believe the report had already appropriately acknowledged the basis for EIA's decision to continue to use 1995 data on control costs rather than EPA's more recent 2001 data.

EIA made this decision primarily because certain industry representatives and EIA advisers thought EPA's data underestimated these costs. However, because the 1995 data used in the model underestimated these costs to an even greater degree, we asked EIA to incorporate the more recent data for the three alternative emissions projections the agency prepared for us. In addition, the Department of Energy's Office of Energy Efficiency and Renewable Energy suggested a number of technical changes, which we have included as appropriate.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 10 days from the report date. At that time, we will send copies to the Chairman and Ranking Minority Member of the House Committee on Energy and Commerce and its Subcommittee on Energy and Air Quality; the House Committee on Government Reform and its Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs; the Ranking Minority Member of the Senate Committee on Environment and Public Works, and its Subcommittee on Clean Air, Wetlands, and Climate Change; other interested members of Congress; the Administrator, EIA; the Administrator, EPA; the Secretary of Energy; the Director of the Office of Management and Budget; and other interested parties. We will also make copies available to others upon request. In addition, the report will be available at no charge on GAO's Web site at http://www.gao.gov.

If you have any questions about this report, please contact me at (202) 512-3841. Key contributors to this report are listed in appendix IV.

John B. Stephenson
Director, Natural Resources and Environment

Appendix I: Scope and Methodology

To address the first objective, we analyzed EIA's reference case projections of future electricity demand and associated air emissions of carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide, on a national and regional basis. To obtain this information, we met with EIA officials responsible for the forecasting model and related emissions projections and reviewed relevant EIA analyses. We focused on EIA's reference case, which accounts for the construction of additional power plants to meet anticipated electricity demand between 2000 and 2020, as well as the retirement of those plants that it projects will become economically unviable.

To address the second objective, we relied on expert advisers who identified alternative assumptions for EIA's model. We identified the advisers using an iterative process (referred to as the "snowball" technique). We first contacted EIA officials responsible for the agency's National Energy Modeling System and its emissions projections to identify individuals within the government, electricity industry, environmental organizations, academia, consulting firms, and other organizations who they believed to be most familiar with EIA's model and electricity forecasting. We also spoke with senior officials within EPA, organizations that perform energy and emissions modeling similar to EIA's, such as Platts/RDI Consulting, and energy and environmental policy analysts from the electricity industry, such as the Electric Power Research Institute, and think tanks, such as Resources For the Future. We spoke with these parties because literature reviews and agency contacts suggested that they would be best positioned to help us identify individuals with the greatest knowledge of energy modeling and related issues. We asked them to identify individuals who are nationally recognized in the fields of energy modeling, electricity demand and fuel price forecasting, emissions control technologies, and related areas. We then contacted these individuals and asked them to identify additional experts in their field. At the conclusion of this process, we had identified 30 individuals and/or organizations.

To select individual advisers from this pool, we applied predetermined criteria that included (1) area of expertise—to provide adequate coverage of representatives with detailed knowledge of relevant disciplines, including electricity modeling and emission control technologies; (2) the number of times an individual was recommended by others in the same field; and (3) professional affiliation—to ensure adequate coverage of key stakeholder groups, including federal agencies, academic institutions, private consulting firms, and nongovernmental organizations. This process resulted in the selection of seven advisers who included a cross section of the various stakeholder groups and specialties. The process was intended to ensure the selection of advisers who represent a broad range of opinions and perspectives. Table 1 includes the names and professional affiliations of the individuals selected.

Table 1: Expert Advisers Who Assisted in Our Review

Adviser	Affiliation	Type of Organization
Joel Bluestein	Energy and Environmental Analysis	Consulting
Steve Clemmer	Union of Concerned Scientists	Environmental
Gordon Hester	Electric Power Research Institute	Industry
Eliot Lieberman	U. S. Environmental Protection Agency	Federal government
Walter Short	National Renewable Energy Laboratory	Federal government
Joseph Sutton	Westpower Management Team	Consulting
Frances Wood	OnLocation, Inc.	Consulting

In addition to the advisers, we retained the services of Arnold Leitner, Ph.D.—a nationally recognized energy forecasting expert with Platts/RDI Consulting—to analyze the assumptions in EIA's model and perform independent modeling.

To collect information and views from the advisers, we sent them questionnaires which (1) summarized the key variables[1] that EIA officials identified as most directly affecting EIA's emissions projections, and (2) asked specific questions regarding whether they agreed with or would suggest alternatives to EIA's assumptions and findings. We also provided them with a list of EIA's key assumptions and relevant supporting documentation. We asked respondents to provide us with specific alternatives in cases where they disagreed with EIA's assumptions.

After we received and analyzed the advisers' responses, we determined that, while they generally agreed with EIA's overall modeling methodology, they disagreed with many specific assumptions and modeling outputs and suggested a wide range of alternatives. We interpreted this as evidence of the uncertainty associated with long-term energy forecasting. Accordingly, we asked EIA to rerun its model to address the uncertainties. Specifically, we asked EIA to run several scenarios that would identify the lower- and upper-bound of possible

[1]These include electricity demand, new plant costs, the fuel mix for electricity production, expected fuel prices, pollution control equipment costs, and retirements of older plants.

future air emissions based on alternative assumptions identified by the advisers.

We then met with EIA officials to determine how best to conduct the additional modeling. Because we wanted EIA to run cases to reflect our advisers' assumptions that would lead to both higher and lower estimated emissions, the officials suggested rerunning the model using alternative values for electricity demand and fuel prices—the two modeling elements they said had the greatest influence on the model's emissions projections. Instead of using the exact values for electricity demand and natural gas prices the advisers suggested, EIA used values from cases it had already run that most closely matched the advisers' alternatives. For example, EIA used electricity demand values from its high and low macroeconomic cases and natural gas prices from its slow and fast oil and gas technological progress cases. We did not attempt to assess the relative likelihood of the alternatives provided by the advisers or the values EIA used for the additional modeling versus EIA's reference case. Because EIA's model is integrated—it is composed of separate modules, which produce results that, in turn, are used as data or assumptions driving other modules—EIA could not easily substitute some of the other information provided by the advisers.

The specific cases we asked EIA to run included:

- A "revised reference case," using all of the assumptions from EIA's *Annual Energy Outlook 2002* reference case, but including updated EPA data on the costs of controlling nitrogen oxides and revised state emissions "caps" for the power sector, as published in the *Federal Register* on March 2, 2000. The updated costs for controlling emissions of nitrogen oxides were about 9 percent higher than those used in the reference case. Correcting the data on state caps for emissions of nitrogen oxides resulted in using 473,000 tons as the overall limit, rather than the 488,000 tons used in EIA's reference case (a difference of about 3 percent). The net result of these corrected assumptions was a 1 percent decrease in emissions of nitrogen oxides.
- A "low emissions case," using all assumptions as in the revised reference case above, except substituting assumptions about economic growth and technological change that resulted in an electricity demand growth rate that was 4 percent lower than EIA's reference case, and natural gas prices that were 21 percent lower than the reference case.
- A "high emissions case," using all assumptions from the revised reference case, except substituting assumptions about economic growth and technological change that resulted in an electricity demand growth rate

that was 4.5 percent higher than EIA's reference case and natural gas prices that were 30 percent higher than the reference case.

For each of these scenarios we received projections of emissions of carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide on a national and regional basis through 2020.

The alternative electricity demand values and natural gas prices used in the low and high emissions cases did not vary equally from the values used in the reference case. For example, electricity demand was 4 percent lower than the reference case in the low emissions case but 4.5 percent higher in the high emissions case. As a result, the difference in emissions levels between the high emissions case and the reference case tends to be larger than that between the low emissions case and the reference case. The unequal variation from the reference case in each of the additional cases is a function of the alternatives provided by the advisers and EIA's decision to use values for electricity demand and natural gas prices from cases it had already run. While EIA's model is sensitive to these changes, as demonstrated by the wide-ranging results for carbon dioxide and mercury, the results should not be considered a sensitivity analysis. It is also important to note that the high emissions case involved both high gas prices and high electricity demand, which led to large amounts of generation from coal and high carbon dioxide and mercury emissions. It is possible that an alternative case could have similarly high demand but lower emissions of these substances due to lower gas prices. Similarly, the low emissions case had low demand and low gas prices, which led to relatively high levels of generation from natural gas. It is possible that an alternative case could have equally low demand but higher emissions if gas prices were higher.

To respond to the third objective, we obtained and analyzed information from EIA, and a report issued by the California Energy Commission (CEC) that relied on data from the Electric Power Research Institute and the Public Interest Energy Research Program. We used EIA's reference case projections to determine the amount of electricity that EIA expects each type of plant (e.g., steam, turbine, nuclear) to produce in the future. Next, we obtained data on water consumption rates (expressed in gallons per megawatt hour of power produced) for different types of power plants from the CEC report. We then multiplied the projected annual generation produced by each plant type by the typical water use rates. We did not try to incorporate projections of improvements in generation or cooling technologies, which in the past have reduced the amount of water used by power plants. In order to reflect the uncertainty associated with projecting water use by power plants in 2020, we calculated estimates using two extreme assumptions about the methods power plants used for cooling. We first assumed that all power plants adopted “dry cooling”—a method that uses much less water than the current average. Then we assumed that all power plants use “wet-cooling” technology available in 2000. This provided a range of possible water use rates. Assuming all plants adopt wet cooling likely overstates the actual water needs for 2020 because it ignores (1) the likely use by some generators of dry-cooling methods and (2) possible innovations in either generating or cooling technology that would reduce water use.

Appendix II: Projected Emissions through 2020 under Four Alternative Cases

The following tables present information on the projected emissions of carbon dioxide, mercury, nitrogen oxides, and sulfur dioxide through 2020 under EIA's reference case and the three alternative cases EIA prepared for us: the low emissions case, the revised reference case, and the high emissions case. The information in each table includes, by region, the projected volume and percentage changes of the emissions from 2000 to 2020 under the four cases.

Table 2: Carbon Dioxide Emissions Projections under Four Cases, 2000-2020

	EIA reference case		Low emissions case		Revised reference case		High emissions case	
Region	Change in emissions 2000-2020 (million tons)	Percent change 2000-2020	Change in emissions 2000-2020 (million tons)	Percent change 2000-2020	Change in emissions 2000-2020 (million tons)	Percent change 2000-2020	Change in emissions 2000-2020 (million tons)	Percent change 2000-2020
1	154	28	130	24	145	26	148	27
2	31	17	23	12	30	16	45	24
3	53	44	49	40	52	42	68	55
4	59	35	55	32	59	34	67	40
5	44	32	39	28	43	31	67	49
6	6	15	6	14	6	15	12	29
7	7	16	4	9	7	15	17	36
8	47	43	36	33	48	44	80	73
9	201	40	153	30	198	39	300	59
10	35	20	31	18	34	20	52	30
11	77	76	39	39	77	75	92	91
12	74	53	59	42	74	52	82	58
13	38	45	39	47	36	43	98	119
Total U.S.	**827**	**35**	**659**	**28**	**808**	**34**	**1,129**	**48**

Note: The regions included in the table are

1. East Central (East Central Area Reliability Coordination Agreement),
2. Texas (Electric Reliability Council of Texas),
3. Mid-Atlantic (Mid-Atlantic Area Council),
4. Western Great Lakes (Mid-America Interconnected Network),
5. Upper Midwest (Mid-Continent Area Power Pool),
6. New York (Northeast Power Coordinating Council/ New York),
7. New England (Northeast Power Coordinating Council/ New England),
8. Florida (Southeastern Electric Reliability Council/ Florida),
9. Southeast (Southeastern Electric Reliability Council /excluding Florida),
10. Lower Midwest (Southwest Power Pool),
11. Northwest (Western Systems Coordinating Council/ Northwest Power Pool Area),
12. Southwest (Western Systems Coordinating Council/ Rocky Mountain Power Area), and
13. California (Western Systems Coordinating Council/ California-Southern Nevada Power).

Source: EIA.

Table 3: Mercury Emissions Projections under Four Cases, 2000-2020

	EIA reference case		Low emissions case		Revised reference case		High emissions case	
Region	Change in emissions 2000-2020 (lbs.)	Percent change 2000-2020	Change in emissions 2000-2020 (lbs.)	Percent change 2000-2020	Change in emissions 2000-2020 (lbs.)	Percent change 2000-2020	Change in emissions 2000-2020 (lbs.)	Percent change 2000-2020
1	148	1	345	2	368	2	677	3
2	-821	-17	-1,008	-20	-1,199	-24	-989	-21
3	-352	-5	-741	-11	-542	-8	674	10
4	1,173	21	978	17	1,178	20	1,800	32
5	1,350	26	1,351	26	1,347	26	2,170	43
6	-335	-20	-530	-31	-137	-8	68	4
7	32	3	32	3	32	3	46	4
8	659	32	463	22	657	32	1,852	89
9	2,634	13	2,456	12	3,599	18	6,111	31
10	375	7	377	7	377	7	802	15
11	1,058	46	666	29	1,055	47	1,467	65
12	1,286	40	1,090	34	1,283	40	1,308	41
13	32	3	222	29	221	29	1,013	134
Total U.S.	**7,240**	**9**	**5,700**	**7**	**8,240**	**10**	**17,000**	**21**

Note: The regions included in the table are

1. East Central (East Central Area Reliability Coordination Agreement),
2. Texas (Electric Reliability Council of Texas),
3. Mid-Atlantic (Mid-Atlantic Area Council),
4. Western Great Lakes (Mid-America Interconnected Network),
5. Upper Midwest (Mid-Continent Area Power Pool),
6. New York (Northeast Power Coordinating Council/ New York),
7. New England (Northeast Power Coordinating Council/ New England),
8. Florida (Southeastern Electric Reliability Council/ Florida),
9. Southeast (Southeastern Electric Reliability Council /excluding Florida),
10. Lower Midwest (Southwest Power Pool),
11. Northwest (Western Systems Coordinating Council/ Northwest Power Pool Area),
12. Southwest (Western Systems Coordinating Council/ Rocky Mountain Power Area), and
13. California (Western Systems Coordinating Council/ California-Southern Nevada Power).

Source: EIA.

Table 4: Projections of Emissions of Nitrogen Oxides under Four Cases, 2000-2020

	EIA reference case		Low emissions case		Revised reference case		High emissions case	
Region	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020
1	-182	-16	-228	-20	-193	-17	-207	-18
2	-31	-11	-30	-11	-31	-11	-30	-11
3	-6	-3	-3	-1	0	0	1	0
4	44	13	33	10	34	11	29	9
5	60	23	56	22	59	23	66	25
6	-10	-15	-9	-15	-9	-14	-8	-12
7	-12	-18	-14	-21	-12	-19	-3	-4
8	-24	-11	-34	-16	-23	-11	-5	-2
9	-30	-3	-36	-4	-28	-3	-22	-2
10	11	4	13	5	11	4	16	6
11	32	20	10	6	32	20	40	25
12	34	15	26	12	34	15	38	17
13	10	11	9	11	8	10	45	54
Total U.S.	**-104**	**-2**	**-204**	**-5**	**-118**	**-3**	**-41**	**-1**

Note: The regions included in the table are

1. East Central (East Central Area Reliability Coordination Agreement),
2. Texas (Electric Reliability Council of Texas),
3. Mid-Atlantic (Mid-Atlantic Area Council),
4. Western Great Lakes (Mid-America Interconnected Network),
5. Upper Midwest (Mid-Continent Area Power Pool),
6. New York (Northeast Power Coordinating Council/ New York),
7. New England (Northeast Power Coordinating Council/ New England),
8. Florida (Southeastern Electric Reliability Council/ Florida),
9. Southeast (Southeastern Electric Reliability Council /excluding Florida),
10. Lower Midwest (Southwest Power Pool),
11. Northwest (Western Systems Coordinating Council/ Northwest Power Pool Area),
12. Southwest (Western Systems Coordinating Council/ Rocky Mountain Power Area), and
13. California (Western Systems Coordinating Council/ California-Southern Nevada Power).

Source: EIA.

Table 5: Sulfur Dioxide Emissions Projections under Four Cases, 2000-2020

	EIA reference case		Low emissions case		Revised reference case		High emissions case	
Region	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020	Change in emissions 2000-2020 (thousand tons)	Percent change 2000-2020
1	-950	-29	-888	-27	-982	-29	-987	-31
2	28	8	29	8	-21	-5	80	23
3	-298	-29	-428	-42	-472	-47	-485	-47
4	-207	-21	-252	-25	-128	-14	-202	-21
5	38	8	28	6	51	11	37	8
6	-96	-35	-118	-42	-89	-33	-80	-28
7	-76	-32	-98	-40	-79	-32	-16	-6
8	-102	-27	-158	-41	-93	-26	-47	-12
9	-376	-12	-304	-9	-248	-8	-380	-12
10	33	8	33	8	38	9	38	9
11	-59	-36	-67	-41	-59	-36	-56	-33
12	-1	0	-5	-3	-2	-1	-1	0
13	-21	-23	-5	-8	-5	-9	12	20
Total U.S.	**-2,088**	**-19**	**-2,088**	**-19**	**-2,088**	**-19**	**-2,088**	**-19**

Note: The regions included in the table are

1. East Central (East Central Area Reliability Coordination Agreement),
2. Texas (Electric Reliability Council of Texas),
3. Mid-Atlantic (Mid-Atlantic Area Council),
4. Western Great Lakes (Mid-America Interconnected Network),
5. Upper Midwest (Mid-Continent Area Power Pool),
6. New York (Northeast Power Coordinating Council/ New York),
7. New England (Northeast Power Coordinating Council/ New England),
8. Florida (Southeastern Electric Reliability Council/ Florida),
9. Southeast (Southeastern Electric Reliability Council /excluding Florida),
10. Lower Midwest (Southwest Power Pool),
11. Northwest (Western Systems Coordinating Council/ Northwest Power Pool Area),
12. Southwest (Western Systems Coordinating Council/ Rocky Mountain Power Area), and
13. California (Western Systems Coordinating Council/ California-Southern Nevada Power).

Source: EIA.

Appendix III: Comments from the Energy Information Administration

Department of Energy
Washington, DC 20585

OCT 0 8 2002

John B. Stephenson
Director, Natural Resources and Environment
General Accounting Office
441 G Street NW
Washington, DC 20548

Dear Mr. Stephenson:

The Energy Information Administration (EIA) appreciates the opportunity to assist the General Accounting Office (GAO) in responding to its request from Senators Jeffords and Lieberman. We agree with the general results of the GAO report that power sector emissions over the next 20 years are uncertain and sensitive to many factors, among them the rate of growth in the demand for electricity and the price of natural gas. It is because of this uncertainty that EIA's Annual Energy Outlook (AEO) includes 30 cases with alternative assumptions about the cost and performance of energy supply and consumption technologies, economic growth, world oil prices and electricity demand growth. EIA encourages readers of the AEO to review the full breadth of cases presented rather than concentrating solely on the reference case. As stated in the report:

> "The projections in AEO2002 are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected."[1]

While we generally agree with the results presented, there are areas of the report that readers may misunderstand or find confusing without more information. These areas are summarized below:

[1] Energy Information Administration, Annual Energy Outlook 2002, With Projections to 2020, DOE/EIA-0383(2002), December 2001, page ii.

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The discussion of the process used to identify individuals who were requested by GAO to review EIA's analysis in the 5th paragraph of the report does not include the names and affiliation of the individuals who participated. The information is provided in Appendix I of the report, but it would be helpful to provide a citation to the appendix here so that readers could evaluate the reviewers' comments based on who they are and their affiliation.
In the Results in Brief section (1st full paragraph on page 3) the report states, "The projected mercury emissions could decrease, however, once the Environmental Protection Agency (EPA) proposes mercury limits, which are required by 2004 and which EIA's modeling did not take into account". The final clause in the sentence gives the impression that EIA failed to include an existing regulation, which is untrue. Our policy, as noted in the AEO, is to incorporate laws and regulations once they have been finalized. Thus, until EPA issues final rules on mercury limits, EIA would not incorporate them in its reference case forecasts.

In the Results in Brief section (bottom of page 4) the report states, "Separately, in working with EIA's model we found that the agency had not used the most current data on certain emissions limits." The same point is repeated using similar language on pages 16 (1st paragraph) and 18 (underlined statement). These statements give the impression that EIA made a critical mistake, which is not the case. EIA's analysis incorporated nitrogen oxide limits that take effect in 19 states (22 states were originally included but 3 are involved litigation of this issue) and the District of Columbia beginning in 2004, by assuming values that had been published by EPA in the Federal Register prior to final adjustments. EIA used an assumed limit of 488,000 tons based on the original EPA Federal Register notice instead of the 473,000 ton final limit (a 3-percent difference). Although EIA meets regularly with industry and government experts, including EPA staff, in the development of its forecasts, these changes were not brought to our attention. Comparing the results in the AEO reference case to those in the GAO reference case presented in this report shows that correcting this oversight has negligible impact. The final limit will be incorporated in EIA's Annual Energy Outlook 2003.

The report asserts that the cost and performance assumptions for nitrogen oxide (NOx) removal equipment (discussed on page 17) used outdated information. We disagree and feel the most widely accepted information available was used. We used nitrogen oxide control costs developed by EPA in 1995. In discussions with industry, the Department of Energy's (DOE) Office of Fossil Energy and the National Energy Technology Center (NETL), we found that these equipment cost and performance assumptions were generally accepted. EPA updated this information in 2001, mainly increasing its estimates for both the cost and performance of selective catalytic reduction (SCR), a key NOx removal

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technology. We found that industry groups and experts in DOE and NETL did not agree with these updates, because the cost of achieving the higher level of removal assumed by EPA in its revised estimates was, in their opinion, under-estimated. Estimates of the costs of recently installed SCRs received from industry also supported this view. For this reason, we continued to use the earlier cost and performance estimates.

In the Background section (bottom of page 5) the report states, "EIA's 2002 projections are based on federal, State, and local laws and regulations in effect on September 1, 2001; its model does not incorporate pending legislation." We believe that this statement gives the impression that we do not include existing laws or regulations that take effect in the future, which is untrue. A clearer statement would be that EIA's projections include existing laws and regulations that have been fully implemented. EIA's analysis does not include laws and regulations where required standards, limits, or compliance programs have not been established.

The comment from the report advisors (page 17, middle paragraph) on EIA's projected natural gas prices states, "One of them noted that EIA's methodology relied on the extrapolation of recent trends and, therefore, depends heavily on how well the future market matches this historical pattern." This statement completely mis-characterizes the methodology we use to estimate future natural gas prices. The National Energy Modeling System (NEMS) incorporates an extremely detailed representation of the natural gas exploration, production, and delivery sectors together with equally detailed representations of the residential, commercial, industrial, transportation and electricity consumption sectors. The cost of finding, developing and delivering natural gas from the known resource base are represented. Resource estimates are regularly updated using official government estimates, and parameters related to exploration and production are re-estimated each year. In any given year the balancing of natural gas supply and demand, using a Gauss-Seidel integrating algorithm, determines the price of natural gas. For those interested in more detail the documentation can be found at: **http://www.eia.doe.gov/bookshelf/docs.html.**

The report states (page 17, last sentence), "According to an EIA official, higher gas prices increase the reliance on coal plants." This statement needs more clarification. Higher natural gas prices would not be expected to have much impact on the operation of existing coal plants. Existing coal plants are quite economical and are expected to operate intensively under most circumstances. Higher natural gas prices would make new natural gas plants less economical and could likely lead to the construction of more new coal plants in the future to meet new capacity demand.

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The first paragraph at the top of page 19 describes the cases in this analysis, saying "At our request, EIA developed ...." A better description is, "With assumptions provided by GAO, EIA prepared alternative emissions projection cases."

In the Conclusions section (page 27) the report states, "And while the advisors disagreed with some of EIA's values for future electricity demand and fuel price trends, they, and EIA, recognize that forecasting is imprecise and that it is difficult to determine which set of alternative assumptions is most likely to occur." We think that it would be useful to point out that EIA includes 30 cases with alternative assumptions about the cost and performance of energy supply and consumption technologies, economic growth, world oil prices and electricity demand growth in its AEO to address the uncertainty inherent in mid- to long-term forecasting and that EIA continually strives through technical working groups and other regular meetings to insure that we are using the best available information and methodologies in our analyses.

We appreciate the opportunity to comment.

Sincerely,

Guy F. Caruso
Administrator
Energy Information Administration

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Appendix IV: GAO Contacts and Staff Acknowledgments

GAO Contacts

John B. Stephenson (202) 512-3841
Eileen R. Larence (202) 512-6510

Acknowledgments

In addition to the individuals named above, Michael Hix, Vincent Price, and Laura Yannayon made key contributions to this report. Important contributions were also made by Frank Rusco and Amy Webbink.

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