2. Analysis Cases and Methodology

Background

The House Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs requested that the Energy Information Administration (EIA) prepare an analysis to evaluate the impacts of potential caps on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury (Hg) with and without a renewable portfolio standard (RPS) requirement.

In its earlier report,[8] EIA analyzed the impacts of meeting the NO_x, SO_2, and CO_2 caps specified by the Subcommittee. The current report extends that analysis to add the impacts of reducing power sector Hg emissions and phasing in an RPS that reaches 20 percent by 2020. The Subcommittee originally requested cases with alternative compliance dates—some with a 2005 date and some with a 2008 date. The previous analysis showed that the earlier compliance dates caused much more pressure on natural gas markets in the early years, but the results in the longer term were similar. In addition, two of the bills introduced in the 107th Congress now call for compliance in 2007 rather than 2005. The Subcommittee staff indicated that, because 2005 is less than 5 years away, this analysis should focus on scenarios with a 2008 compliance date.

Reference Case

The reference case for this analysis is based on the reference case for EIA's *Annual Energy Outlook 2001* (*AEO2001*).[9] As a result, it incorporates the laws and regulations that were in place as of the end of August 2000. It includes the CAAA90 SO_2 emission cap and NO_x boiler standards. It also includes the 19-State summer season NO_x emission cap program—referred to as the "State Implementation Plan (SIP) Call." (See box on page 9 for a discussion of the treatment of environmental rules and regulations in the reference case.) The settlement agreement between the Tampa Electric Company and the Department of Justice (acting for the U.S. Environmental Protection Agency [EPA]) requiring the addition of emissions control equipment at the Big Bend power plant and the conversion of the F.J. Gannon plant to natural gas was incorporated in the *AEO2001* reference case.

Because of the recent agreements between the EPA and Cinergy and Virginia Power with respect to the New Source Review compliance action,[10] the *AEO2001* reference case has been modified for this study to incorporate the emissions control equipment that those companies have announced they will add. The historical data used for this analysis were also updated to reflect more recent information on natural gas prices, electricity sales, and generating capability additions in 2000 that were not available when the *AEO2001* reference case was prepared.

Since the December 2000 publication of EIA's earlier report on multiple emission reduction strategies, the method for computing reductions of NO_x emissions when generators are retrofitted with more than one control technology has been revised. Previously, generators received additive credit in percentage reduction terms for retrofits of both combustion controls (such as low NO_x burners) and post-combustion controls (either selective catalytic reduction or selective noncatalytic reduction) in instances where the model chose to use both options sequentially. Now, generators receive the applicable full percentage reduction for the first control added, and then the second percentage reduction is applied to the already reduced emission rate. This change results in higher estimates of NO_x emissions and, consequently, higher projected prices for NO_x emission allowances. Estimated NO_x allowance prices are more than 100 percent higher in the reference and NO_x 2008 cases and about 86 percent higher in the SO_2 2008 case.

In addition, natural gas prices and electricity demands have been recalibrated to EIA's latest *Short-Term Energy Outlook* (*STEO*). This recalibration resulted in higher gas prices and electricity demand than those used as baseline values in December 2000. Ambitious CO_2 reduction targets would be expected to place extreme demands on natural gas supply and distribution, and certain features have been added to the natural gas model to represent hypothetical industry responses to unprecedented requirements. Chief among these are the representation of an LNG facility in Baja California, Mexico, and potentially high levels of natural gas imports.

[8]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000) (referred to here as "the earlier EIA report").

[9]Energy Information Administration, *Annual Energy Outlook 2001*, DOE / EIA-0383(2001) (Washington, DC, December 2000).

[10]See chapter 5 of the earlier EIA report for discussion of New Source Review isues.

Analysis Cases

The specific assumptions and cases requested by the Subcommittee are summarized in Table 1 and described in detail below. The analysis cases examine the impacts of each emission cap and the RPS singly and in various combinations.

Table 2 summarizes the emission targets and timetables analyzed. The emission caps (Table 2 and Figure 1) are applied only to the electricity generation sector, excluding cogenerators, and are assumed to cover emissions from both utility-owned and independent electric power plants. Cogenerators are treated as industrial facilities in this analysis. Because no requirements to reduce emissions in the residential, commercial, industrial, and transportation sectors are assumed, the results of this analysis are not directly comparable with the results of studies that have examined the impacts of complying with the Kyoto Protocol across all sectors of the economy.

In all cases it is assumed that emission caps for NO_x, SO_2, and CO_2 would be phased in beginning in 2002. The cap on Hg emissions is assumed to begin in the compliance year (2008). For the cases that require that CO_2 emissions average 7 percent below the 1990 level over the 2008 to 2012 period, the cap is constructed so that emissions are slightly above the 1990-7% level in the first year or two of the period and slightly below it in the later years. After 2012, the cap is held at 7 percent below the 1990 level through the remainder of the projections. In addition, it is assumed that the emission reduction programs will be operated as market-based emission cap and trade programs patterned after the SO_2 allowance program, and the emission allowance prices are included in the operating costs of plants that produce one or more of the emissions.

Because there is an existing national SO_2 allowance program, it is assumed that power plant operators will be able to use any SO_2 allowances they have already accumulated. However, they are not allowed to bank additional allowances after 2000. As a result, the power sector can exceed the SO_2 emission cap beyond the compliance date until its banked allowances are exhausted. If banking were allowed after 2000, compliance costs could be lower than shown in this report, because power companies might be able to "overcomply" in the early years of the program and use the allowances banked to delay the need to meet the final program cap.

With respect to CO_2, because the caps are applied only to the U.S. power sector, it is assumed that power producers must explicitly reduce emissions to meet the cap and cannot rely on other mechanisms, such as the flexibility measures included in the Kyoto Protocol that would allow countries several options for meeting their emission reduction targets, including land use changes and forestry changes. Under the Kyoto Protocol, a country could get credit for a project to plant trees (reforestation) that absorb CO_2 during their growth. Emissions trading among countries with emission caps would also be permitted by the Protocol. The Protocol also covers six greenhouse gases—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—and reductions in any one of them would count toward meeting a country's emissions cap. However, rules about what type of land use and forestry projects could be implemented and how emissions trading programs might work have not been finalized.

The power sector emissions bills in Congress do not explicitly include flexibility mechanisms similar to those in the Kyoto Protocol. Therefore, this study assumes that U.S. power companies would be able to trade emissions allowances with other U.S. power companies but that they would not be able to trade with U.S. firms in other sectors or with foreign entities. If similar provisions were included in a program to reduce power sector CO_2 emissions, the costs of meeting the CO_2 reduction target would be lower.

In this analysis, it is assumed that marketable emissions allowances or permits would be allocated to power plant operators at no cost (no revenue would be collected by the government). For hazardous air pollutants such as Hg, the law requires the EPA to set maximum achievable control technology (MACT) standards rather than using a cap and trade system; however, the EPA has said, "There is considerable interest in an approach to Hg regulation for power plants that would incorporate economic incentives such as emissions trading."[11] A sensitivity case using a MACT approach for Hg is described in the next section.

Chapter 4 discusses the macroeconomic impacts of the no-cost emission allocation program. It also describes the potential economic impacts of a government auction of allowances, with a rebate of the revenue that would be collected. No assumption is made about the specific allocation methodology to be used, other than that the allocation will be fixed (will not change from year to year) and the total amounts allocated will equal the national emission targets for NO_x, SO_2, CO_2, and Hg. Holders of allowances are assumed to be free to use them to cover emissions from their own electric power plants or sell them to others who need them.

As allowances are bought and sold, market prices will develop for them and will become part of the operating costs of plants producing the targeted emissions. For

[11] *Federal Register*, Vol, 65, No. 245 (December 20, 2000), pp. 79825-79831.

example, the total operating costs of a plant that produced one ton of a targeted emission per unit of output would be increased by the price of the allowance. Revenues associated with the sale of allowances would go to the seller of the allowances. In all cases it is assumed that the allowance markets will operate as near perfect markets, with low transaction costs and without information asymmetries. In other words, there will be many buyers and sellers of allowances, and information needed to evaluate their worth will be readily available.

Table 1. Reference and Analysis Cases

Case Name	Electric Power Sector Emissions Caps				Compliance Date/ Other	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
Reference	CAAA90 standards and NO_x SIP Call	CAAA90 cap (8.95 million tons)	None	None	CAAA90	Current State programs[a]
NO_x 2008	75% below 1997 level	CAAA90 cap (8.95 million tons)	None	None	Start 2002; meet target by 2008	Current State programs
SO_2 2008	CAAA90 standards and NO_x SIP Call	75% below 1997 level	None	None	Start 2002; meet target by 2008	Current State programs
CO_2 1990-7% 2008	CAAA90 standards and NO_x SIP Call	CAAA90 cap (8.95 million tons)	7% below 1990 level	None	Start 2002; meet CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012[b]	Current State programs
Hg 5-Ton	CAAA90 standards and NO_x SIP Call	CAAA90 cap (8.95 million tons)	None	90% below 1997 level	2008	Current State programs
RPS 20%	CAAA90 standards and NO_x SIP Call	CAAA90 cap (8.95 million tons)	None	None	CAAA90	5% 2005, 10% 2010, 20% 2020
Integrated Cases						
Integrated NO_x, SO_2, CO_2 1990	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet targets by 2008	Current State programs
Integrated NO_x, SO_2, CO_2 1990, Hg	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet $NO_x/SO_2/CO_2$ targets by 2008; Hg 2008	Current State programs
Integrated All CO_2 1990	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet $NO_x/SO_2/CO_2$ targets by 2008; Hg 2008	5% 2005, 10% 2010, 20% 2020
Integrated NO_x, SO_2, CO_2 1990-7%	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; meet NO_x/SO_2 targets by 2008; meet CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012[b]	Current State programs
Integrated NO_x, SO_2, CO_2 1990-7%, Hg	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; meet NO_x/SO_2 targets by 2008; meet CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012;[b] Hg 2008	Current State programs
Integrated All CO_2 1990-7%	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; meet NO_x/SO_2 targets by 2008; meet CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012;[b] Hg 2008	5% 2005, 10% 2010, 20% 2020

[a]The impacts of current State RPS programs are estimated off line and input as new plant construction.
[b]The CO_2 emission cap remains at the 1990-7% level from 2012 through 2020.

Notes: CAAA90 cap refers to the 8.95 million ton SO_2 cap established in Title IV of the Clean Air Act Amendments of 1990 (CAAA90). CAAA90 standards refer to the boiler emission standards for NO_x established in Title V of the CAAA90. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. Integrated refers to combinations of emissions caps and/or a renewable portfolio standard (RPS).

Source: See requesting letters in Appendix A for specific cases requested by the Subcommittee.

In cases with an RPS it is assumed that a renewable credit trading system would be established. In other words, each nonhydroelectric renewable generator would be issued a credit for each kilowatthour of electricity generated. The generator would be able to keep the credits for its own use or sell them to others. To meet the required renewable share, a power seller could either purchase electricity directly from nonhydroelectric renewable plants or purchase credits.

It should be pointed out that there are numerous policy instruments (taxes, emissions standards, tradable permits, etc.) that could be used to reach the proposed emission targets.[12] The choice of policy instrument will have an impact on the costs of complying with the emission targets, the resource cost, and the electricity price impacts seen by consumers. Alternative policy instruments, such as a dynamic generation performance standard, are being considered.[13] A no-cost allowance

Table 2. 1990 and 1997 Emissions Levels, Reference Case Projections for 2008, and Assumed Emissions Caps for Electricity Generators

Target	NO_x (Thousand Tons)	SO_2 (Thousand Tons)	CO_2 (Million Metric Tons Carbon Equivalent)	Hg (Tons)
1990 Level	6,663	15,909	475	NA
1997 Level	6,191	13,090	533	52
2008 Reference Case Level	4,310	9,940	674	46
Emissions Caps	1,548	3,273	440/475[a]	5

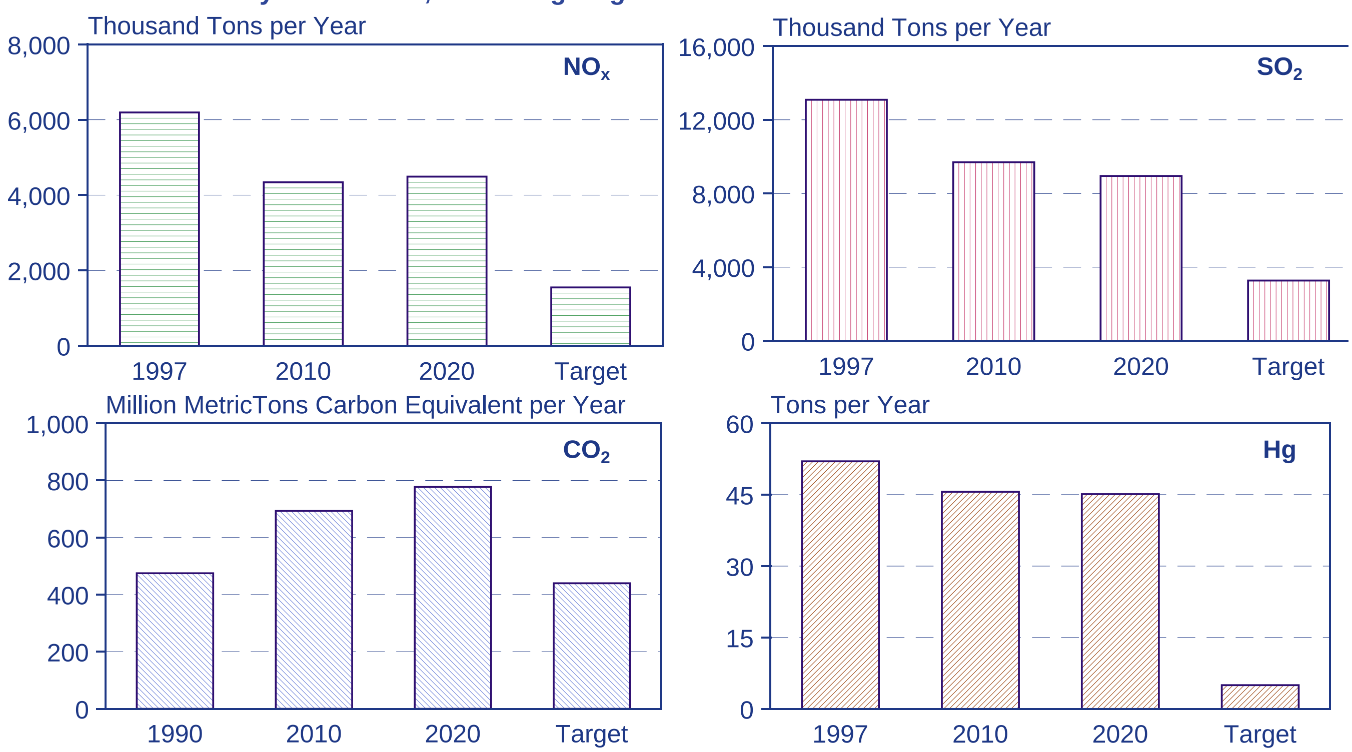
[a]Two alternative CO_2 emissions targets are used: 1990 level (475 million metric tons carbon equivalent) and 1990-7% level (440 million metric tons carbon equivalent).

NA = not applicable.

Note: The EPA's 1997 mercury report to Congress estimated that the power sector produced 51.8 tons of mercury in the 1994-1995 period, and this value is used here as representative of emission levels in 1997. Actual 1990 and 1997 values are not available. See Environmental Protection Agency, *Mercury Study Report to Congress*, EPA-452/R-97-003 (Washington, DC, December 1997).

Source: 1997 levels from U.S. Environmental Protection Agency, *National Air Pollutant Emission Trends, 1900-1998*, EPA-454/R-00-002 (Washington, DC, March 2000).

Figure 1. Historical Emissions, Reference Case Projections for 2010 and 2020, and Target Caps for Electricity Generators, Excluding Cogenerators



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run AEO2001.D101600A.

[12]See page 12 of the earlier EIA report.

[13]See page 14 of the earlier EIA report. See also J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf; and D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, *The Effect of Allowance Allocation on the Cost and Efficiency of Carbon Emission Trading* (Washington, DC: Resources for the Future, April 2001).

Representation of New Environmental Rules and Regulations

In Energy Information Administration (EIA) analyses, the reference case incorporates rules and regulations in place at the time of the analysis. Rules or regulations not finalized, in early stages of implementation (without specific guidelines), or still being developed or debated are not represented. As an independent statistical and analytical agency, EIA does not take positions on how legislative or regulatory issues will be resolved or how regulations will, or should, be implemented.

The reference case for this analysis excludes several potential environmental actions, such as new regulations affecting regional haze, for which States are developing implementation plans; new National Ambient Air Quality Standards (NAAQS) for particulates, still being reviewed by the U.S. Environmental Protection Agency (EPA) and the courts; and the possible ratification of the Kyoto Protocol. In addition, no effort is made to predict the Hg emission reductions that may be required[a] or the outcome of lawsuits against the owners of 32 coal-fired power plants accused of violating the Clean Air Act (CAA).[b]

In 1999, the EPA issued regulations to improve visibility (reduce regional haze) in 156 national parks and wilderness areas across the United States. It is expected that these rules will have an effect on electric power plants, but the degree to which they will be affected is not known. Emissions of SO_2 and NO_x contribute to regional haze, and reductions could improve visibility in some areas. The regulations call for States to establish goals and design plans for improving visibility in affected areas; however, State implementation plans (SIPs), which are not required until 2004 or later, are not represented in this analysis.

The revised NAAQS, issued by the EPA in 1997, created a standard for fine particles smaller than 2.5 micrometers in diameter ($PM_{2.5}$). Power plant emissions of SO_2 and NO_x are also a component of fine particulate emissions. The EPA is now reviewing scientific data on fine particulate emissions to determine whether the standard should be revised. The review is expected to be completed in 2002. If the standard is not changed, States will be required to submit plans to comply by 2005; however, the NAAQS for fine particulates has been challenged in court, and the resolution of the case is uncertain.

In December 1997, 160 countries met to negotiate binding limitations on greenhouse gas emissions for the developed nations. CO_2 emissions from fossil-fired power plants are a key component of greenhouse gas emissions. The developed nations agreed to limit their greenhouse gas emissions to 5 percent below the levels emitted in 1990, on average, between 2008 and 2012. The target for the United States is 7 percent below the 1990 emission level for all greenhouse gases. Reductions would be required if the U.S. Senate ratified the protocol. At this time, while 29 countries have ratified the protocol, none of the Annex I countries (the developed countries) has ratified the agreement. Various elements of the Protocol are still under negotiation. In addition, the Bush Administration opposes ratification of the Protocol in its present form.

The Clean Air Act Amendments of 1990 (CAAA90), Section 112(n)(1)(A), required that the EPA prepare a study of hazardous air emissions from steam generating units. The report was submitted to Congress on February 24, 1998. Its key finding was that Hg emissions from coal-fired power plants posed the greatest potential for harm. The EPA is now collecting and analyzing data on Hg emissions from specific power plants. The data, together with continuing studies on the health effects of mercury, will be used to determine the extent to which emissions need to be reduced. The EPA will be developing proposed regulations for reducing Hg emissions over the next 3 years.

On November 3, 1999, the Justice Department, on behalf of the EPA, filed suit against seven electric utility companies, accusing them of violating CAAA90 by not installing state-of-the-art emissions control equipment on power plants when major modifications were made. CAAA90 requires that when major modifications are made to older power plants they must also be upgraded to comply with emissions standards for new plants. The EPA is arguing that the seven companies and the Tennessee Valley Authority made major modifications to 32 power plants but did not add required emissions control equipment. Settlements have been reached in some cases, but most are ongoing.

Readers should keep in mind that some of the projected actions and costs incurred to comply with the emissions caps analyzed in this report may also result from the other pending rules and regulations discussed above when they are finalized. Projections in the reference case in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference 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. All laws are assumed to remain as now enacted, although the impacts of emerging regulatory changes, when defined, are reflected.

[a]On December 15, 2000, the EPA announced that Hg emissions need to be reduced, and that regulations will be issued by 2004.
[b]See Chapter 5 of the earlier EIA report for discussion of New Source Review issues.

allocation together with a cap and trade system is assumed in this report, because it has been used before in the United States and because it provides power suppliers and consumers with incentives to minimize the cost of meeting the emission targets.

Sensitivity Cases

As in any analysis of this type, there is uncertainty about some of the key assumptions made. For example, the results are influenced by uncertainty about the cost and performance of new, yet to be fully tested or commercialized, Hg removal technologies; the impacts of alternative emissions targets; the policy instrument(s) to be used to reduce emissions; future fuel prices; and ongoing changes in electricity pricing as the industry is restructured. To illustrate the impacts of uncertainty in these areas, a variety of sensitivity cases has been prepared.

Table 3 summarizes the key assumptions for each of the sensitivity cases. Because of the considerable uncertainty surrounding the measurement and control of power plant Hg emissions, three sensitivity cases were prepared. One assumes a less stringent emission cap, one makes alternative assumptions about the development of technologies to remove Hg, and one assumes that all electric power plants will be required to achieve a 90-percent target level of Hg reduction without a cap and trade system.

The 20-ton Hg emission cap case shows the sensitivity of the cost and price impacts to alternative emission caps. The Hg 5-ton recycle case assumes that Hg control systems using a supplemental fabric filter are redesigned so that most of the activated carbon that is injected can be recycled through the system, reducing the need for activated carbon by 90 percent. It is assumed that the capital cost of the system will be 50 percent higher than one without recycling, but the cost savings associated with the reduction in activated carbon use more than offsets the increase. The assumptions made in the Hg 5-ton recycle case should be seen not as projections of expected research and development outcomes but rather as illustrative of the level of uncertainty that exists about the control of Hg emissions and the expectation that technological improvements will occur. At this time, such systems are only in the research and development stage, and it is unclear what level of recycling may be feasible.

The final Hg sensitivity case, the Hg MACT 90% case, uses an alternative policy instrument to control Hg emissions. Because mercury is a hazardous pollutant under the Clean Air Act, the law may require the EPA to make plants install the maximum achievable control technology (MACT) to reduce it. In the MACT case, all plants must reduce their emissions of Hg by 90 percent (measured from the mercury contained in the coal), and no cap and trade system is established.

In addition to the Hg sensitivity cases, a case is prepared with a less aggressive RPS target, and an integrated case is prepared with less stringent caps for each of the emissions together with the less aggressive RPS target. Also, an integrated sensitivity is prepared assuming that emissions allowances are treated as having zero cost for pricing purposes in regions where electric power industry restructuring has not occurred. In many parts of the country the methodology used to price electricity—especially in the wholesale market—is currently changing. Historically, power prices have been based on embedded costs. In other words, all the costs associated with building and operating electric power plants were summed and divided by expected sales to determine the price per kilowatthour. As the generation market becomes more competitive, however, power prices are increasingly being set by the costs of the most expensive generator operating at any point in time—what economists refer to as the “marginal cost.” This change could have significant impacts on the way in which emission allowance prices affect electricity prices and the resource costs of meeting the emission caps.

In competitive markets, allowance prices will become part of the operating costs of any generator producing the covered emission. Allowance prices may have a different impact on electricity prices in regulated markets where prices are set according to cost of service. For example, if a company in a regulated region were allocated allowances at no cost, the regulatory authority would not include allowance prices when setting retail electricity prices. Conversely, if the regulated utility purchased allowances—from the government or from another utility—the cost of the allowances would likely be reflected in retail electricity prices. In the integrated cost of service CO_2 1990-7% 2008 case it is assumed that allocated allowances will have zero cost in regions that have not deregulated. While this would lead to lower price impacts, the resource costs are likely to be higher because consumers will not have the same incentive to reduce electricity consumption.

Finally, recognizing the impact of natural gas supply and demand on electricity markets, the integrated high gas price CO_2 1990-7% 2008 case assumes that technologies associated with the finding, developing, and delivery of natural gas will not improve as rapidly as expected, and that additional Alaskan production and LNG imports projected in other cases with a CO_2 cap will not occur, resulting in higher natural gas prices.

Methodology

NEMS Representation

EIA's National Energy Modeling System (NEMS) is a computer-based, energy-economic model of the U.S. energy system for the mid-term forecast horizon, through 2020. NEMS projects production, imports, conversion, consumption, and prices of energy, subject to assumptions about macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. Using econometric, heuristic, and linear programming techniques, NEMS consists of 13 submodules that represent the demand (residential, commercial, industrial, and transportation sectors), supply (coal, renewables, oil and natural gas supply, natural gas transmission and distribution, and international oil), and conversion (refinery and electricity sectors) of energy, together with a macroeconomic module that links energy prices to economic activity. An integrating module controls the flow of information among the submodules, from which it receives the supply price and quantity demanded for each fuel until convergence is achieved.[14]

Domestic energy markets are modeled by representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most sectors, NEMS includes explicit representation of energy technologies and their characteristics (Table 4). In each sector of NEMS, economic agents—for example, representative households in the residential demand sector and producers in the industrial sector—are assumed to evaluate the cost and performance of various energy-consuming technologies when making their investment and utilization decisions. The costs of

Table 3. Sensitivity Cases

Case Name	Electric Power Sector Emission Caps				Compliance Date/ Other	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
Hg 20-Ton	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	60% below 1997 level	Meet target by 2008	Current State programs
Hg 5-Ton Recycle	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	90% below 1997 level	Meet target by 2008; assumes technology developed to recycle 90% of activated carbon	Current State programs
Hg MACT 90%	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	90% removal for all plants, no trading system	Meet target by 2008	Current State programs
RPS 10%	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	None	CAAA90	2.5% 2005, 5% 2010, 10% 2020
Integrated Moderate Targets	CAAA90 standards and NO_x SIP Call	50% below 1997 level	7% above 1990 level	70% below 1997 level	Start 2002; meet NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% above 1990 level in 2008-2012;[a] Hg 2008	2.5% 2005, 5% 2010, 10% 2020
Integrated Cost of Service	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; meet NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012;[a] Hg 2008; assumes allowances have zero cost basis in cost-of-service regions	Current State programs
Integrated High Gas Price	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; meet NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% below 1990 level in 2008- 2012;[a] Hg 2008; assumes slower improvement in technologies for finding, developing and delivering natural gas.	Current State programs

[a]The CO_2 emission cap remains at the 1990-7% level from 2012 through 2020.

Notes: CAAA90 cap refers to 8.95 million ton SO_2 cap established in Title IV of the Clean Air Act Amendments of 1990 (CAAA90). CAAA90 standards refers to the boiler emission standards for NO_x established in Title V of the CAAA90. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. Integrated refers to combinations of emissions caps and/or an RPS.

Source: See requesting letters in Appendix A for specific cases requested by the Subcommittee.

[14]For more information, see web site www.eia.doe.gov/bookshelf/docs.html, which provides documentation of the NEMS submodules.

making capital and operating changes to comply with laws and regulations governing power plant and other emissions are included in the decisionmaking process.

The rich detail in NEMS makes it useful for evaluating various energy policy options. Policies aimed at a particular sector of the energy market often have collateral effects on other areas that can be important, and the detail of NEMS makes the analysis of such impacts possible. The remainder of this chapter describes how the cases for this analysis were implemented in the key NEMS submodules for electricity, coal, and renewables. Changes in assumptions and modeling approaches for this analysis are also explained.

To represent power sector Hg emissions and technologies for removing them, extensive modifications were made to the *AEO2001* version of the model. While more detail is given below, the key changes include expanding the representation of coal plants and adding Hg removal technologies to the Electricity Market Module, and adding Hg content to the coal supply curves in the

Table 4. National Energy Modeling System Energy Activities

Energy Activity	Categories	Regions
Residential Demand	Fourteen end-use services Three housing types Thirty-four end-use technologies	Nine Census divisions
Commercial Demand	Ten end-use services Eleven building types Ten distributed generation technologies Sixty-four end-use technologies	Nine Census divisions
Industrial Demand	Seven energy-intensive industries Eight non-energy-intensive industries Cogeneration	Four Census regions
Transportation Demand	Six car sizes Six light truck sizes Fifty-nine conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and thirteen alternative-fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Narrow and wide body aircraft Six advanced aircraft technologies Medium and heavy freight trucks Ten advanced freight truck technologies	Nine Census divisions
Electricity	Eleven fossil technologies Seven renewable technologies Conventional and advanced nuclear Marginal and average cost pricing Generation capacity expansion	Thirteen electricity supply regions Nine Census divisions for demand
Renewables	Wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, biomass, conventional hydropower	Thirteen electricity supply regions
Oil Supply	Conventional onshore and shallow offshore Conventional deep offshore Enhanced oil recovery	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural Gas Supply	Conventional onshore and shallow offshore Conventional deep offshore Coalbed methane Gas shales Tight sands Canadian, Mexican, and liquefied natural gas	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions Five liquefied natural gas terminals
Natural Gas Transportation and Distribution	Core vs. noncore Peak vs. offpeak Pipeline capacity expansion	Twelve lower 48 regions Ten pipeline border points
Petroleum Refining	Five crude oil categories Seven product categories Thirty-three technologies Refinery capacity expansion	Three refinery regions aggregated from Petroleum Administration for District Districts
Coal Supply	Three sulfur categories Four thermal categories Underground and surface mining types	Eleven supply regions Thirteen demand regions Sixteen export regions Twenty import regions

Source: Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000).

Coal Market Module. These changes allow the model to choose the most economical option for reducing Hg emissions when an emission cap is imposed.

Electricity Market Module

The representation of laws and regulations governing power plant emissions is particularly important in the NEMS Electricity Market Module (EMM). The *AEO2001* version of the EMM was able to simulate emission caps on SO_2, NO_x, and CO_2. The EMM simulates the capacity planning and retirement, operating, and pricing decisions that occur in U.S. electricity markets. It operates at a 13-region level based on the North American Electric Reliability Council (NERC) regions and subregions. Based on the cost and performance of various generating technologies, the costs of fuels, and constraints on emissions, the EMM chooses the most economical approach for meeting consumer demand for electricity.

During each year of the analysis period, the model evaluates the need for new generating capacity to meet consumer needs reliably or to replace existing electric power plants that are no longer economical. The cost of building new capacity is weighed against the costs of continuing to operate existing plants and consumers' willingness to pay for reliable service. For nuclear facilities, maintenance versus retirement decisions are made for each plant when it reaches 30, 40, and 50 years of age. At the request of the Subcommittee, the option of constructing new nuclear plants is not considered in this analysis.[15]

The model represents improvements in the cost and performance of new generating technologies as they enter the market. Economic research has shown that successful new technologies tend to show declining costs as they penetrate the market and manufacturers learn to improve design and manufacturing techniques. In the model it is assumed that the costs for new technologies decline as they penetrate the market. As a result, if a policy stimulates the development of a particular technology, the model will endogenously reduce the cost of that technology as it enters the market in greater quantities. The rate of decline depends on the level of penetration.

The steps taken to reduce NO_x, SO_2, CO_2, and Hg emissions affect the price of electricity. The model has the option to price power (the generation component of the electricity business) in either a regulated cost-of-service environment or a competitive market environment. Generally, in regions in which the majority of the electricity sales are in States that have passed legislation or enacted regulations to open their retail markets, generation prices are assumed to be derived competitively. The fully competitive regions include California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey, and Maryland), and Texas. In regions where only a portion of the States have opened their retail markets, the regulated and competitive generation prices are weighted (by the share of sales in the respective states) to derive an average regional price. These regions include the East Central Area, the Rocky Mountain-Arizona regions, the Mid-America Interconnected Network, and the Southwest Power Pool. In all the other regions power prices are assumed to continue to be regulated. However, because wholesale generation markets throughout the country are moving toward competition, all new generators are assumed to be built as merchant power plants that will sell their power at market-based rates.

Through the end of 1999, 24 States and the District of Columbia had enacted restructuring legislation or regulatory orders. Together these States accounted for more than 55 percent of U.S. wholesale electricity sales in 1999. Eighteen other States are studying deregulation. In combination with the States that have already taken action, they accounted for more than 88 percent of sales in 1999. In addition, the vast majority of new power plant additions are expected to be built by deregulated entities. In several States, however, degregulation plans have recently been put on hold, and it is unclear when they might move forward.

Nearly 77 percent of the additions to electricity generating capacity that have been planned over the next 4 years and reported to EIA are from nonutility entities. For this reason, this analysis treats the allowance prices that arise with emission caps as if they were imposed on competitive wholesale markets. The allowance prices become part of the operating costs of electric power plants that produce the targeted emissions. If, however, a large portion of the generation market remains under cost of service pricing over the next 20 years, the fact that allowances are allocated at no cost to generators could reduce the price impacts from those seen in this analysis. Essentially, cost-of-service utilities could be forced by regulators to treat any allowances allocated to them as having zero cost, and they would not reflect any cost for them in their rates. A sensitivity case, the integrated cost of service case, illustrates the potential impact of this issue.

In competitive regions, generation prices are based primarily on the operating costs of the power plant setting the market-clearing price at any given time. In other words, the plant producing power with the highest operating costs sets the price of generation during each time period. Using a loss of load probability algorithm, an additional cost is estimated to reflect consumers' willingness to pay for reliable service, especially during high usage periods. When emission caps are imposed,

[15]See Appendix A, letter from Subcommittee staff dated August 17, 2000.

the allowance costs or fees associated with them become part of the operating costs for electric power plants that produce the affected emissions. As a result, in competitively priced regions, the fees or allowance costs for SO_2, NO_x, CO_2, and Hg become part of the operating costs for electric power plants that burn fossil fuels.

When a plant needing emission permits sets the market price for power, the per-kilowatthour cost of holding the permits is reflected in the retail electricity price. This can lead to increased profits for companies that own plants with zero or low emissions or those that can reduce emissions easily. Equally important is the possibility that when the costs associated with reducing emissions or holding allowances fall on plants that do not set the market price, the plant owners may not be able to pass any of them on to consumers. For example, if the market-clearing prices in a region are set by natural-gas-fired plants with no SO_2 emissions, a coal-fired plant that added scrubbers to reduce SO_2 emissions would not see any increase in revenue to cover the scrubber costs. In regulated regions, the total costs associated with adding emissions control equipment, using more expensive fuels, and retiring or replacing plants to reduce SO_2, NO_x, and CO_2 emissions are assumed to be recovered along with the allowance costs.

Representation of SO_2, NO_x, and CO_2 Emission Reductions

During each time period,[16] plants are brought on line (dispatched), starting with the unit with the lowest operating costs, until consumers' demand is met. When an SO_2 or NO_x emission cap is placed on electricity producers, the least expensive reduction options available are chosen until the cap is met. The goal of the model is to minimize the costs of meeting the demand for electricity while complying with emissions constraints. For example, to reduce SO_2 emissions, the options include switching to a lower sulfur fuel; reducing the utilization of relatively high SO_2 emitting plants; adding a flue gas desulfurization (FGD) system to an existing plant to remove SO_2; retiring a relatively high emitting plant and replacing it with a cleaner plant or, through higher prices, encouraging consumers to reduce their electricity use. The approach includes SO_2 allowance trading and banking for later use. The marginal cost of reducing emissions sets the allowance price, which is included in the operating costs of plants producing emissions. In NEMS, SO_2 allowance banking decisions can be specified exogenously, or the model can solve for them endogenously. In this analysis, because the relationships among the emission caps are complex, banking patterns for SO_2 allowances were specified exogenously for each case. The bank of 11.6 million tons of SO_2 allowances accumulated through 1999 was assumed to be used between 2000 and 2015 in each case.

To reduce NO_x emissions, the options include decreasing the utilization of relatively high emitting plants; adding combustion controls that remove NO_x from the exhaust gases of a plant (i.e., low-NO_x burners) and / or post-combustion controls (i.e., selective noncatalytic reduction [SNCR] or selective catalytic reduction [SCR] equipment); retiring high emitting plants; or, through higher prices, encouraging consumers to reduce their electricity use. For this analysis the emission caps on SO_2 and NO_x specified by the Subcommittee are treated as annual national caps, and allowance trading is allowed among plants throughout the country. The stringency of the annual NO_x cap eliminates the need for the summer season NO_x cap established by the SIP call. It is assumed that the NO_x program would operate like the existing SO_2 allowance program. As with the SO_2 program, the marginal cost of reducing NO_x emissions sets the allowance price.

To reach the power sector CO_2 emissions target, the model chooses among investments in lower emitting technologies (mainly new natural gas and renewables), changes in operations and retirement decisions for existing and new electric power plants (using lower emitting resources more intensively than higher emitting resources and maintaining low emitting resources such as nuclear), and conservation activities by consumers (induced by higher prices). The model solves for the allowance price that forces power suppliers and consumers to make sufficient changes in investment, operations, and conservation activities to meet the cap. In this analysis the CO_2 cap is applied only to the power sector, because emissions in other sectors of the economy are not restricted in the cases specified by the Subcommittee.

While the EMM has the ability to represent new coal and gas-fired power plants with CO_2 capture and sequestration equipment, the relatively near-term timing of the emission cap programs analyzed in this report make it unlikely that they would play a large role. The Department of Energy has ongoing research aimed at developing a nearly zero emission coal plant, but the target calls for developing these plants for commercialization between 2015 and 2020. As a result, they are not considered in this analysis.

Representation of Hg Emission Reductions in the EMM

The ability to represent Hg emissions and emission reductions has been added to the EMM for this analysis. To do so, the number of existing coal plant types was expanded from 7 to 32 (Table 5). Each of these plant types represents a different configuration of NO_x, particulate, and SO_2 emission control devices, together with options for removing Hg. The Hg removal rates for each

[16]The EMM dispatches over 108 time periods: 6 seasons, 3 types of day, 3 time periods per day, and 2 blocks per time period.

of the coal plant configurations were estimated from data collected by the EPA in its mercury information collection request (ICR) in 1999. In addition to the removal rates shown in Table 5, 7 percent of Hg in the coal is assumed to be removed in the boiler, and this is reflected in the combined rates shown.

Although significant uncertainty about estimating Hg emissions remains (see box on page 16), the data collected suggest that together with the Hg content of the coal consumed by the plant, each of these types of devices has an impact on how much Hg is ultimately emitted into the air. For example, it is estimated that a fabric filter (baghouse) for controlling particulate emissions will also remove 69 percent of the Hg emitted from a plant using bituminous coal. The emissions modification factors (EMFs) listed in Table 5 show the percentage of Hg in the coal that remains in the flue gas after passing through all of the plants' existing emissions control equipment before the addition of Hg control equipment, which further reduces Hg. The EMFs reflect the fact that existing SO_2, NO_x, and particulate control equipment also reduces Hg emissions.

The Hg control options include various combinations of activated carbon injection with and without a retrofitted spray cooling system and/or fabric filter. The cost and amount of activated carbon injection needed to achieve a target level of Hg removal were developed from model parameters estimated by the National Energy Technology Laboratory (NETL). Because the NETL model was developed from pilot-scale tests before the ICR data

Table 5. Coal Plant Configurations, Emissions Modification Factors, and Mercury Control Options

Plant Configuration			Emissions Modification Factors (Fraction Remaining) by Coal Rank						Hg Control Option Available
			SO_2 Control		Particulate	SCR	Combined		
SO_2 Control	Particulate Control	SCR	Subbituminous/ Other	Bituminous	All Coal Ranks	All Coal Ranks	Subbituminous/ Other	Bituminous	
None	BH	NA	1.00	1.00	0.31	1.00	0.288	0.288	Injection
None	BH	NA	1.00	1.00	0.31	1.00	0.288	0.288	Injection/SC
Wet	BH	No	0.81	0.34	0.31	1.00	0.234	0.098	Injection
Wet	BH	No	0.81	0.34	0.31	1.00	0.234	0.098	Injection/SC
Wet	BH	Yes	0.81	0.34	0.31	0.65[a]	0.152	0.064	Injection
Wet	BH	Yes	0.81	0.34	0.31	0.65[a]	0.152	0.064	Injection/SC
Dry	BH	NA	0.61	0.61	1.00	1.00	0.567	0.567	Injection
Dry	BH	NA	0.61	0.61	1.00	1.00	0.567	0.567	Injection/SC
None	CSE	NA	1.00	1.00	0.69	1.00	0.642	0.642	Injection
None	CSE	NA	1.00	1.00	0.69	1.00	0.642	0.642	Injection/FF
None	CSE	NA	1.00	1.00	0.69	1.00	0.642	0.642	Injection/SC/FF
Wet	CSE	No	0.81	0.34	0.69	1.00	0.520	0.218	Injection
Wet	CSE	No	0.81	0.34	0.69	1.00	0.520	0.218	Injection/FF
Wet	CSE	No	0.81	0.34	0.69	1.00	0.520	0.218	Injection/SC/FF
Wet	CSE	Yes	0.81	0.34	0.69	0.65[a]	0.338	0.142	Injection
Wet	CSE	Yes	0.81	0.34	0.69	0.65[a]	0.338	0.142	Injection/FF
Wet	CSE	Yes	0.81	0.34	0.69	0.65[a]	0.338	0.142	Injection/SC/FF
Dry	CSE	NA	0.61	0.61	1.00[b]	1.00	0.567	0.567	Injection
Dry	CSE	NA	0.61	0.61	1.00[b]	1.00	0.567	0.567	Injection/SC/FF
Dry	CSE	NA	0.61	0.61	1.00[b]	1.00	0.567	0.567	Injection/FF
None	HSE/Other	NA	1.00	1.00	1.00	1.00	0.930	0.930	None
None	HSE/Other	NA	1.00	1.00	1.00	1.00	0.930	0.930	Injection/FF
None	HSE/Other	NA	1.00	1.00	1.00	1.00	0.930	0.930	Injection/SC/FF
Wet	HSE/Other	No	0.81	0.34	1.00	1.00	0.753	0.316	None
Wet	HSE/Other	No	0.81	0.34	1.00	1.00	0.753	0.316	Injection/FF
Wet	HSE/Other	No	0.81	0.34	1.00	1.00	0.753	0.316	Injection/SC/FF
Wet	HSE/Other	Yes	0.81	0.34	1.00	0.65[a]	0.490	0.206	None
Wet	HSE/Other	Yes	0.81	0.34	1.00	0.65[a]	0.490	0.206	Injection/FF
Wet	HSE/Other	Yes	0.81	0.34	1.00	0.65[a]	0.490	0.206	Injection/SC/FF
Dry	HSE/Other	NA	0.61	0.61	1.00	1.00	0.567	0.567	None
Dry	HSE/Other	NA	0.61	0.61	1.00	1.00	0.567	0.567	Injection/FF
Dry	HSE/Other	NA	0.61	0.61	1.00	1.00	0.567	0.567	Injection/SC/FF

[a]SCRs are assumed to reduce Hg emissions only when combined with a wet scrubber designed to remove SO_2.

[b]CSEs do not remove additional Hg when combined with a dry scrubber.

Notes: BH = bag house, CSE = cold side electrostatic precipitator, FF = fabric filter, HSE = hot side electrostatic precipitator, SC = spray cooler, SCR = selective catalytic reduction. NA = not applicable. An emissions modification factor (EMF) of 0.93 is assumed for all boiler configurations and is incorporated in the derivation of the combined EMFs.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Power Sector Mercury Emissions

Many factors, including the Hg content (by speciation—elemental Hg versus various Hg-containing compounds), chlorine content, and other chemical constituents of the coal used; the rank of the coal (i.e., bituminous or subbituminous); the boiler temperature and firing type and the flue gas temperature; and the types of existing control equipment for NO_x, SO_2, and particulates affect the level of Hg emissions from a particular power plant. In recent years data collection and analysis efforts have focused on these factors so that better estimates of current power sector Hg emissions could be developed; however, substantial uncertainty remains. As additional tests are performed, factors currently unaccounted for may turn out to be important.

Section 112(n)(1)(A) of the Clean Air Act Amendments of 1990 required the U.S. Environmental Protection Agency (EPA) to perform a study of possible public health problems associated with hazardous air pollutants from steam-electric power plants. That study was completed in December 1997 and transmitted to the Congress.[a] One of its key findings was that Hg emissions from coal-fired power plants posed the greatest public health concern among the hazardous air pollutants identified; however, the EPA determined that more data were needed before regulatory decisions could be made.

Using its authority under section 114 of the Clean Air Act, in November 1998 the EPA issued an information collection request (ICR) requiring coal-fired power plants to provide data associated with Hg emissions. The ICR data were collected in three phases. The first phase involved the collection of basic information—boiler type, size, existing emissions control equipment, etc.—for every coal-fired generator with 25 megawatts or greater capacity. The second phase was the collection of fuel shipment information for each of the electric power plants identified in the first phase. Each of the electric power plants was required to report the quantity and source of each coal shipment received for the calendar year 1999. For every sixth shipment (a minimum of 3 analyses per month) the plants also had to report the Hg and chlorine content of the coal received. In the third phase of the ICR, 75 plants were selected to test the Hg emissions at the inlet and outlet of the last pollution control device on one or more units. The plants used were chosen to be representative of the different types of existing coal plants.

The ICR data are the primary information used in this report to assign Hg content to the coal supply curves in the NEMS Coal Market Module and the Hg emissions modification factors for each coal plant type represented in the Electricity Market Module. On average the sample data show that the Hg content of coal shipped in 1999 was 7.3 pounds per trillion Btu (approximately 0.2 pounds of Hg per thousand short tons of coal); however, there was considerable variation among coals from different seams, even within a given coal supply region. For example, the 1999 ICR data indicated that coal shipments from the Pittsburgh seam in Northern Appalachia had an average Hg content of 8.2 pounds per trillion Btu, whereas shipments from the Upper Freeport seam averaged 16.4 pounds Hg per trillion Btu. Even within the same coal seam the tested shipment data show considerable variation in Hg content. For example, although the average Hg content for the Pittsburgh seam was 8.2 pounds per trillion Btu, the minimum for shipments from that seam was 0.1 pounds per trillion Btu and the maximum was 73.1 pounds per trillion Btu. In statistical terms, the standard deviation for Hg content at the Pittsburgh seam is 4.04, indicating that most samples should have Hg contents between 0.1 and 16.3 pounds of Hg per trillion Btu.

The Hg removal rates for the various coal plant configurations also showed significant variation. Data from the third phase of the ICR show that on average a cold-side electrostatic precipitator (CSE)—a particulate removal device—removes 31 percent of the Hg that passes through it. However, the variation among plants with CSEs was large, ranging between 0 percent and 87 percent removal. The situation was similar for facilities with fabric filters—another type of particulate removal device. On average they removed 69 percent of the Hg passing through them, but, after excluding plants that actually reported increases in Hg after passing flue gas through the fabric filter, the removal rate ranged between 54 percent and nearly 100 percent. In addition, there is very little information on the impact of new NO_x control devices—selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment—on Hg emissions because, while many plants plan to add them in the near future, only a few are using them now. This study assumes that, when combined with an SO_2 scrubber, an SCR enhances Hg removal with an emissions modification factor of 0.65; however, no additional removal is assumed for plant configurations that have an SCR but do not have an SO_2 scrubber.

Additional research is needed on the variations seen in the available data. Over the next several years the National Energy Technology Laboratory (NETL), the

(continued on page 17)

[a]U.S. Environmental Protection Agency, *Mercury Study Report to Congress*, EPA-452/R-97-003 (Washington, DC, December 1997).

Power Sector Mercury Emissions (Continued)

EPA, and others plan to conduct full-scale tests of various Hg removal technologies on several coal plants. This analysis assumes the use of activated carbon injection technologies to remove Hg, because they have been tested at pilot scale; however, there are other technologies in development, including advanced coal cleaning techniques, alternative absorbents, and more efficient use of absorbents (recycling absorbents rather than once-through systems) to remove Hg from flue gas.

In addition, efforts to understand the role of chlorine and other chemicals in coal on the amount of Hg removed are underway. Data from those tests and from other ongoing research should allow a better understanding of the factors influencing Hg emissions and improve analyses of options for reducing them. Although this report uses the best data available, considerable uncertainty exists about the measurement of and options for reducing Hg emissions from coal-fired power plants.

collection, the model parameters were adjusted to make them consistent with the ICR results.[17] The pilot-scale tests generally involved taking a small portion of the flue gas flow from an existing plant (referred to as a slip stream test), injecting varying levels of activated carbon and measuring the amount of Hg removed. The equations used to determine the amount of activated carbon needed to achieve a target level of removal have the form:

$$\textit{Percent Hg Removal} = 100 - (a / (ACI + b)) * \textit{Shift} \quad ,$$

where:

- *a* and *b* are curve fitting parameters developed by NETL[18]
- *ACI* is the amount of activated carbon injected
- *Shift* is the adjustment made to make the equations consistent with the ICR results.

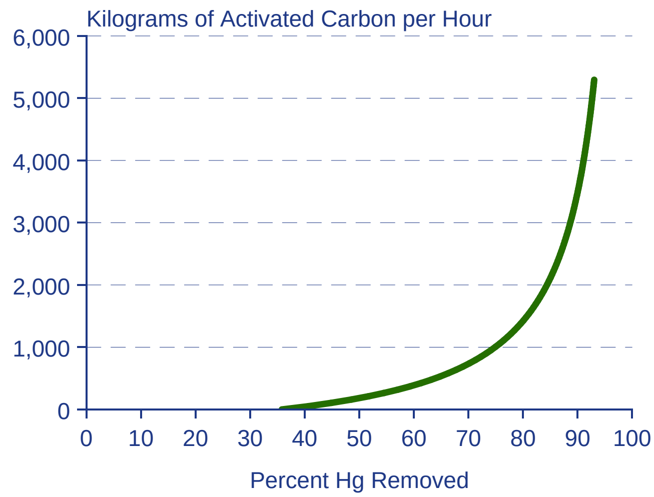
Figure 2 illustrates the impact of injecting activated carbon for a common plant configuration—a 500-megawatt coal-fired power plant using bituminous coal with an electrostatic precipitator. The percentage of Hg removed increases with the amount of activated carbon injected; however, the amount of activated carbon needed also grows for each incremental amount of Hg removed.

Based on information from the NETL, it is assumed that activated carbon will cost $1 per kilogram or $0.45 per pound. The capital costs of adding an activated carbon injection system vary with the option chosen. For a 500-megawatt coal plant using subbituminous coal the cost assumptions are: simple injection, $2.40 per kilowatt; simple injection plus a spray cooler, $10.00 per kilowatt; simple injection plus a fabric filter, $37.60 per kilowatt; and a simple injection system with spray cooler and fabric filter, $45.20 per kilowatt.

Considerable uncertainty exists about the validity of the estimated injection levels needed to remove 90 percent or more of the Hg from a plant, because the pilot scale programs generally did not test injection levels of the magnitude needed to achieve that level of removal. It also should be noted that, at this time, no full-scale tests using activated carbon injection to remove Hg from coal plants have been performed. As a result, the analysis of Hg reduction options and costs in this report may be different from actual data when they become available.

When Hg emissions caps are imposed, the model solves for the most economical way to meet the caps by choosing among all the various options. It can choose to reduce coal use, switch to a lower Hg coal, and/or add control equipment to remove Hg. In addition to—or instead of—the activated carbon options discussed, the model can choose to add SO_2 and NO_x control equipment (which also reduces Hg emissions) to meet a given Hg cap. SO_2 scrubber costs in the analysis are unit specific, with 41 gigawatts having costs under $200 per kilowatt, 64 gigawatts having costs between $200 and $300

Figure 2. Activated Carbon Use for Hg Removal



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[17]The NETL model parameters were used to calculate the amount of activated carbon injection required to achieve a target Hg removal level. Those target levels for each plant configuration serve as Hg removal supply steps in the capacity planning module of the EMM. The costs for constructing and operating a carbon injection and disposal system and (when called for) a spray cooling and fabric filter system were estimated assuming a 500-megawatt plant with a heat rate of 10,000 Btu per kilowatthour using 12,000 Btu per pound coal.

[18]These parameters differ by coal rank and plant configuration.

per kilowatt, and 119 gigawatts having costs over $300 per kilowatt. The higher cost units are generally smaller plants. Scrubbers are assumed to remove 95 percent of the SO_2 when added. The cost to add an SCR to control NO_x also varies by unit, with the average cost being $52 per kilowatt. The NO_x removal rates for SCRs vary between 70 and 80 percent.

Representation of the Renewable Portfolio Standard

To represent the RPS, the EMM has the ability to require that generation from nonhydroelectric renewable facilities (including all generation from cogenerators) be equal to or greater than a specified amount. In this analysis the required amount is determined by multiplying the specified share in a given year by the total projected sales of electricity in that year. The most economical nonhydroelectric renewable options are constructed to meet the RPS requirement.

As with the emission cap programs described above, the RPS program is assumed to operate as a market credit system. It is not required that each power seller produce or purchase the required renewable share. Instead, they must hold renewable "credits" equal to the required share. Credits are issued to those producers generating power from qualifying renewable facilities and, as in the case of SO_2 allowances, may be sold to others. The projected price of the credits becomes part of the operating costs of nonqualifying facilities. In each of the RPS cases it is assumed that the program continues through 2020 and that there is no legislated limit on the credit price. In this analysis, all nonhydroelectric renewable generating technologies are assumed to be covered by the RPS, including wind, solar, biomass, municipal solid waste, landfill gas, and geothermal. With respect to municipal solid waste, only 61 percent—the portion estimated to come from woody material—is assumed eligible to receive credits.

Coal Market Module

The Coal Market Module (CMM) provides annual forecasts of prices, production, and distribution of coal to the various consumption and energy transformation sectors in NEMS. It simulates production from 11 coal supply regions that meets demands for steam and metallurgical coal from 13 U.S. demand regions and incorporates an international coal trade component that projects world coal trade, including U.S. coal exports and imports.

Representation of Coal Rank in the NEMS Coal Market Module

The thermal grades represented in the NEMS Coal Market Module (CMM) primarily correspond to three ranks of coal: bituminous, subbituminous and lignite. In the United States, coals are grouped into specific rank categories based on fixed carbon content, volatile matter, heating value, and agglomerating (or caking) properties. The classification of coals according to rank is based on their degree of progressive alteration from lignite to anthracite.

In the CMM, bituminous coal is represented by two thermal grades: (1) a premium bituminous coal that is supplied to the domestic and foreign coking coal sectors and used to make coke for the steelmaking process; and (2) a bituminous steam coal consumed in the electricity, industrial, and residential/commercial sectors. Like bituminous steam coal, subbituminous coal and lignite also are consumed in the electricity, industrial, and residential/commercial sectors. Anthracite coal from Pennsylvania is not uniquely modeled in the CMM but is grouped with bituminous coal in Northern Appalachia (Pennsylvania, Ohio, northern West Virginia, and Maryland). An additional supply curve representing supplies of waste bituminous and anthracite coals in Northern Appalachia is also represented in the CMM. Currently, waste coals are consumed primarily by independent power producers.

There is some indication coal rank is correlated with the capability of different technologies to remove Hg from the stack gases of electric power plants (see Table 5), but it is not entirely clear why Hg removal rates vary by coal rank. A number of factors are known to affect Hg removal, such as chlorine content of the coal, the chemical state of the Hg in the coal (elemental or in compound), boiler temperature and firing type, and flue gas temperature. Others are not yet well understood, such as the ability of fly ash itself (generated during combustion) to absorb Hg. Chlorine reacts with elemental Hg during combustion to form oxidized Hg, which is more effectively removed from the flue gas of coal-fired units equipped with wet SO_2 scrubbers.[a]

Data on chlorine content, from the U.S. Environmental Protection Agency's 1999 Information Collection Request, typically indicate a substantial difference in chlorine content between bituminous and subbituminous coals. For example, the average chlorine content associated with the CMM coal supply curves for bituminous coals from the Northern Appalachian and Central Appalachian (southern West Virginia, Virginia and eastern Kentucky) regions ranges from approximately 800 to 1,200 parts per million (ppm), whereas the average chlorine content of low-sulfur subbituminous coal from the Powder River Basin (Wyoming and Montana) region is 120 ppm.

[a]N. Shick, "Mercury's Pathways to Fish," *EPRI Journal*, Vol. 8 (December 22, 2000).

The model uses a linear programming (LP) algorithm to determine the least-cost supplies of coal (minemouth price, transportation cost, plus the cost of activated carbon to remove Hg) by supply region for a given set of coal demands in each demand sector in each demand region. Separate supply curves are developed for each of 11 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type—see box on page 18). The modeling approach used to construct the 35 regional coal supply curves represented in the model addresses the relationship between the minemouth price of coal and corresponding levels of coal production, labor productivity, and the cost of factor inputs (mining equipment, mine labor, and fuel requirements).

In 1999, coal consumed in the electric power sector represented approximately 90 percent of total U.S. coal consumption. In turn, coal-fired power plants (including electric utilities, independent power producers, and cogenerators) accounted for almost 52 percent of the electricity generated from all energy sources during the year. Steam coal is also consumed in the industrial sector to produce process heat, steam, and synthetic gas and to cogenerate electricity. Metallurgical coal is used to make coke for the iron and steel industry. Approximately 6 million tons of steam coal is consumed in the combined residential and commercial sector annually. An increasing share of U.S. coal production has been directed to the domestic market in recent years, with U.S. coal exports currently representing only about 5 percent of production.

Coal is heterogeneous in terms of its energy, sulfur, nitrogen, carbon, and Hg content. Thus, the geographic source of coal can be a significant factor in the physical quantity of coal necessary to provide a given quantity of energy and in the resultant level of emissions. Coal prices also vary significantly according to heat content, quality, and regional source. For example, low-sulfur, low-Btu coal from the Powder River Basin in Wyoming and Montana has a minemouth price that is only about 20 percent that of some coal types mined in the Appalachian region. The variation in regional coal prices, coupled with shifts across cases in the amount of coal originating from each region, can lead to changes in U.S. average minemouth prices that are more related to altered distribution patterns than to the level of aggregate coal demand.

During each year of the forecast period, the CMM receives a set of coal demands, expressed in terms of British thermal units (Btu), required by the different sectors in each region. The demands from the electricity generation sector derived in the EMM are further disaggregated into seven categories within each demand region that depend on boiler age, maximum allowable sulfur, and scrubber availability. The EMM also provides the SO_2 and Hg caps (expressed in tons) that represent the maximum emission level for that year. Based on these requirements, and subject to given coal contracts, a linear program within the CMM solves for a supply pattern that meets all demands at minimum cost, subject to the sulfur and Hg caps. The allowance price is calculated from this methodology; it is essentially the cost of reducing the last ton of SO_2 or Hg under the specified annual caps. The allowance prices, in turn, are used by the EMM to evaluate the economics of adding appropriate environmental control equipment to coal-fired generators.

For the most part, the CMM assumptions used for the reference case of this study are the same as those used for the *AEO2001*. However, the SO_2 2008 case and the cases with CO_2 caps incorporate two significant revisions to the CMM assumptions used for the reference case with regard to the size and duration of existing contracts between coal suppliers and electricity generators. In the CO_2 cap cases all coal supply contracts were modified to be phased out by 2003. In the SO_2 2008 case all contracts for delivery of high-sulfur coal to power plants not equipped with SO_2 scrubbers were assumed to be phased out by 2008, because accelerated and more stringent SO_2 emission restrictions were thought to be likely to constitute sufficient justification to end such contracts under *force majeure* measures.

Representation of Hg Emission Reductions in the CMM

Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu (Table 6), were derived from shipment-level data reported by electricity generators to the EPA in its 1999 ICR. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities.

Data inputs to the CMM were calculated as weighted averages specified by supply region, coal rank, and sulfur category. Reported Hg data were weighted by the amount of coal contained in each of the sampled shipments received at the plants. The Hg inputs to the CMM varied from a low of 2.04 pounds of Hg per trillion Btu for low-sulfur subbituminous coal originating from mines in the Rocky Mountain (Colorado and Utah) supply region to 63.90 pounds of Hg per trillion Btu for waste coal originating from sites in Northern Appalachia (Pennsylvania, Ohio, northern West Virginia, and Maryland).

Activated carbon injection (ACI) during the coal combustion process may be used on an incremental basis to achieve various levels of Hg emission reductions. Its use impacts the coal mix used to satisfy coal demand. Low use of activated carbon, for instance, may imply a relatively higher use of low-Hg coals. For the same Hg cap, high use of activated carbon may allow the use of coals higher in Hg, and thus less coal switching may be necessary. Therefore, in order to determine the extent of coal switching, the model needs to anticipate how much activated carbon may be used.

The costs of removing Hg using activated carbon are included in the coal model's LP objective function. They are derived in the EMM and passed to the CMM. Each cost represents the amount spent on activated carbon to remove one ton of Hg and corresponds to a particular coal generation plant configuration, coal demand region, and Hg reduction quantity range. They are recalculated by the EMM in each model iteration, and the coal model is subsequently updated.

The type of coal, emission control equipment (such as scrubbers), and the use of activated carbon are all factors considered within the coal LP's Hg cap constraint. First, Hg removal rates resulting from various coal plant technologies (excluding carbon injection) are supplied by the EMM to the CMM. Second, the adjusted Hg content of coal (tons of Hg per trillion Btu) is calculated from the removal rates and the amount of Hg present in the coal itself (post-coal preparation). Third, adjusted Hg content is then multiplied by the quantity of coal (trillion Btu) transported to the demand regions, yielding tons of potential Hg emissions (pre-ACI). Finally, this value minus the tons of Hg removed by carbon injection is constrained to be less than or equal to the Hg cap for a given year. The model can switch or blend coal inputs to reduce Hg emissions when those options are economical.

Renewable Fuels Module

The Renewable Fuels Module (RFM) consists of five submodules that represent the major nonhydroelectric renewable energy resources: biomass, geothermal,

Table 6. Coal Production and Quality Data by Region, Coal Type, and Mine Type

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	1998 Production (Million Short Tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds per Million Btu)	Hg Content (Pounds per Trillion Btu)	CO_2 Emissions (Pounds per Million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	6.2	26.80	0.67	NA	205.4
		Low-Sulfur Bituminous	All	2.7	24.71	0.56	11.62	203.6
		Mid-Sulfur Bituminous	All	80.5	25.54	1.26	11.16	205.4
		High-Sulfur Bituminous	All	68.3	24.28	2.69	11.67	203.6
		Waste Coal (Gob and Culm)	Surface	8.6	12.43	1.74	63.90	203.6
Central Appalachia	KY (East), WV (South), VA	Metallurgical	Underground	62.2	26.80	0.61	NA	203.8
		Low-Sulfur Bituminous	All	63.9	25.17	0.54	5.61	203.8
		Mid-Sulfur Bituminous	All	150.9	24.84	0.85	7.58	203.8
Southern Appalachia	AL, MS, TN	Metallurgical	Underground	5.7	26.80	0.49	NA	203.3
		Low-Sulfur Bituminous	All	8.1	25.11	0.53	3.87	203.3
		Mid-Sulfur Bituminous	All	11.9	24.58	1.19	10.15	203.3
East Interior	IL, IN, KY (West)	Mid-Sulfur Bituminous	All	34.4	22.73	1.16	5.60	201.4
		High-Sulfur Bituminous	All	75.8	22.45	2.75	6.35	201.4
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	2.7	24.52	2.64	21.55	202.4
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	27.5	12.83	1.14	14.11	211.4
		High-Sulfur Lignite	Surface	28.0	12.93	2.08	15.28	211.4
Dakota Lignite	ND, MT (Lig)	Mid-Sulfur Lignite	Surface	30.2	13.30	1.14	8.38	216.6
Powder River, Green River, and Hannah Basins	WY, MT (Sub)	Low-Sulfur Subbituminous	Surface	314.9	17.39	0.37	5.68	210.7
		Mid-Sulfur Subbituminous	Surface	40.3	17.67	0.77	5.82	210.7
		Low-Sulfur Bituminous	Underground	1.7	21.54	0.58	2.08	204.4
Rocky Mountain	CO, UT	Low-Sulfur Bituminous	Underground	45.8	23.07	0.42	3.82	203.0
		Low-Sulfur Subbituminous	Surface	9.9	20.55	0.38	2.04	210.6
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	19.5	21.24	0.47	4.66	205.4
		Mid-Sulfur Subbituminous	Surface	20.4	18.26	0.87	7.18	206.7
Northwest	WA, AK	Mid-Sulfur Subbituminous	Surface	6.0	15.70	0.83	6.99	207.9

NA = not available.

Sources: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-3A, "Annual Coal Quality Report—Manufacturing Plants"; Form EIA-5, "Coke Plant Report Quarterly"; Form EIA-5A, "Annual Coal Quality Report—Coke Plants"; Form EIA-860B, "Annual Electric Generator Report—Nonutility"; Form EIA-6A, "Coal Distribution Report—Annual"; and Form EIA-7A, "Coal Production Report." Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999). B.D. Hong and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," in Energy Information Administration, *Quarterly Coal Report*, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

landfill gas, central station solar (thermal and photovoltaic), and wind. The model contains renewable energy resource estimates and costs, defines technology construction and operating costs, and accounts for resource limitations for each renewable generating technology. These characteristics are provided to the EMM for grid-connected central station electricity capacity planning decisions.

Other renewable energy sources modeled elsewhere in NEMS include conventional hydroelectricity (in the EMM), industrial and residential sector biomass, ethanol (in the Petroleum Market Module), geothermal heat pumps, solar hot water heating, and distributed (grid-connected) commercial and residential photovoltaics. Renewable energy technologies and competitive positions are also affected by other characteristics of the EMM, including learning-by-doing, in which capital costs are assumed to decline as more units of a technology enter service, and market-sharing, in which technologies that are not least cost but are near least cost are assigned a small share of the market.

Biomass is represented in the RFM in price-quantity supply schedules. The price-quantity relationship for obtaining biomass fuel is derived from aggregated biomass supply curves that rely on data and modeling done by Oak Ridge National Laboratory to project the quantities of four types of biomass: agricultural residues, energy crops (assumed to be available beginning in 2010), forestry residues, and urban wood waste/mill residues. Biomass can be consumed for electricity generation either by industrial cogenerators (in the industrial sector model) or by electricity generators (in the EMM); electricity generators in the central-station electric power sector can use biomass either in integrated gasification combined-cycle units or by co-firing biomass in coal-fired utility boilers. The amount of biomass allowed in co-firing varies from 0 to 5 percent on a heat input basis, depending on the region in which the coal plant is located. The share of biomass allowed is calculated on the basis of its availability in a particular region.

Biomass co-firing gives coal-fired power plants the ability to meet environmental regulations by using an alternative low-emission fuel. It is assumed that the coal plants will incur no additional capital or maintenance costs to consume up to 5 percent of their fuel as biomass. To go above 5 percent co-firing (which is not allowed in this analysis), plants would have to invest in specialized fuel-processing equipment. Such investments are not expected to be economical under most circumstances. In addition, because the waste materials, trees, and plants that become biomass consume CO_2 during their growth, their net CO_2 emissions are assumed to be zero.

The RFM includes both dual-flash and binary geothermal technologies and contains cost-quantity geothermal resource supply schedules for 51 known geothermal sites in the Western United States.[19] Costs include exploration, drilling, other field costs (pipelines, roads), and power plant costs. For each site, total capacity is distributed among four increasing-cost categories, reflecting assumed increases in exploration and development costs (excluding power plant development). The RFM estimates of geothermal supply are limited by the extent of geothermal resources at unproven sites and by environmental concerns and resultant limits on power plant development in parks and in pristine and scenic areas.

Landfill-gas-to-electricity technologies also compete for U.S. electricity supply, using supply schedules that are based on the number of “high,” “low,” and “very low” methane producing landfills located in each region. Although mass-burn municipal solid waste-to-energy (MSW) facilities are included in the stock of electricity generators, because of their high cost and environmental concerns, the RFM no longer projects that additional mass-burn MSW capacity will be built in the United States.

The EMM also includes central-station solar thermal generating technologies in the western United States, where direct normal solar insolation is sufficient; although specifications describe a central receiver technology, actual builds could include dish-stirling and solar trough units. Solar insolation is such that 5-megawatt central-station grid-connected photovoltaic generators could be located in any region.

Wind power is represented in the RFM via technology cost and performance specifications for contemporary horizontal-axis wind turbines. Wind resources are cost-differentiated by region, wind quality, and distance from existing transmission lines. In addition, wind resources are assumed to become more costly as increasing resource proportions are consumed in each region, in response to declining natural resource quality, increasing costs of utilizing the existing transmission network, and in competition with other potential resource uses (such as parks or urban development). Although total U.S. wind resources are estimated to reach nearly 2.5 million megawatts nationwide, nearly 60 percent is located in the upper Midwest alone, far more than could be economically accessed in or near that region. By and large, economically useful wind resources are relatively generous in the Midwest and the Northwest but are much more limited in California and many parts of Texas and scarce east of the Mississippi River.

[19] Dyncorp Corporation, Contract DE-AC01-95-ADF34277, deliverable DEL-99-548 (Alexandria, VA, July 1997).

This analysis (as in *AEO2001*) includes the production tax credit (PTC) first passed under the Energy Policy Act of 1992 and later extended; however, because the current termination date for the PTC is December 31, 2001, it does not have a significant effect on the analysis. The production tax credit provides 1.7 cents per kilowatthour for the first 10 years of electricity generation for tax-paying entities that build new wind, closed-loop biomass, or poultry waste-burning facilities. In the RFM, only the construction of wind facilities is assumed to be stimulated by the PTC. Closed-loop biomass is assumed not to be available until 2010, and the model does not represent poultry waste-burning facilities.