# 1. Introduction

## Background

### Request for Analysis

The analysis in this report was undertaken at the request of Senators James M. Jeffords (I-VT) and Joseph I. Lieberman (D-CT), subsequent to the report *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, published by the Energy Information Administration (EIA) in December 2000.[1] The analysis in the December 2000 report was expanded in the report *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, published by EIA in July 2001.[2] In the July 2001 report, EIA analyzed the impacts of a number of different limits for sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$), carbon dioxide ($CO_2$), and mercury (Hg) emissions from electricity generators, which varied by level and start year, and a renewable portfolio standard. The analysis was conducted relative to the reference case of the *Annual Energy Outlook 2001* (*AEO2001*),[3] published in December 2000, using EIA's National Energy Modeling System (NEMS).[4]

For this analysis, Senators Jeffords and Lieberman requested that EIA consider the impacts of technology improvements and other market-based opportunities on the costs of emissions reductions from electricity generators. Using 2002 as a start date for emissions reductions, the request specifies that by 2007 $NO_x$ emissions from electricity generators are to be reduced to 75 percent below 1997 levels, $SO_2$ emissions to 75 percent below the full implementation of the Phase II requirements under Title IV of the Clean Air Act Amendments of 1990 (CAAA90), Hg emissions to 90 percent below 1999 levels, and $CO_2$ emissions to 1990 levels (Figure 1). These emissions limits are applied to all electricity generators, excluding cogenerators, which produce both electricity and useful thermal output and account for less than 10 percent of total generation. (Throughout this report cogenerators are excluded when reference to electricity generators is made.)

The impacts of these limits are analyzed against four different cases with varying levels of energy demand: the reference case from *AEO2001*, a case combining the high technology assumptions for end-use demand, supply, and generating technologies from *AEO2001*, and the moderate and advanced policy cases from *Scenarios for a Clean Energy Future* (*CEF*), a publication of an interlaboratory working group, published in November 2000 (Table 1).[5] In general, the emissions limits are achieved through a combination of reductions in energy demand, shifts from coal-fired electricity generation to nuclear, natural gas, and renewable generation, and additional emissions control equipment. Within the time frame of the emissions limits, economical technologies to capture and sequester $CO_2$ are unlikely. Sequestration technologies are included in the analysis but do not penetrate because they are not economical.

This chapter summarizes EIA's previous analysis of multi-emission reduction strategies for electricity generator emissions and the reference case projections of *AEO2001*, describes the methodology of NEMS, and summarizes *CEF*. Chapter 2 presents the impacts and costs of the emissions limits for the reference and advanced technology cases. Chapter 3 presents the impacts and costs for the cases incorporating the moderate and advanced policies from *CEF*. The letter of request is provided in Appendix A, and detailed tables of assumptions incorporated for the industrial sector are provided in Appendix B. Appendix C presents the energy market results for the reference and advanced

[1]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), web site www.eia.doe.gov/oiaf/servicerpt/powerplants/index.html.

[2]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/index.html.

[3]Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), web site www.eia.doe.gov/oiaf/aeo/index.html.

[4]Energy Information Administration, *The National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/index.html.

[5]Interlaboratory Working Group, *Scenarios for a Clean Energy Future*, ORNL/CON-476 and LBNL-44029 (Oak Ridge National Laboratory, Oak Ridge, TN, and Lawrence Berkeley National Laboratory, Berkeley, CA, November 2000), web site www.ornl.gov/ORNL/Energy_Eff/CEFOnep.pdf.

technology cases, and Appendix D presents the results for the cases based on *CEF*.

## Multi-Emission Reduction Policies

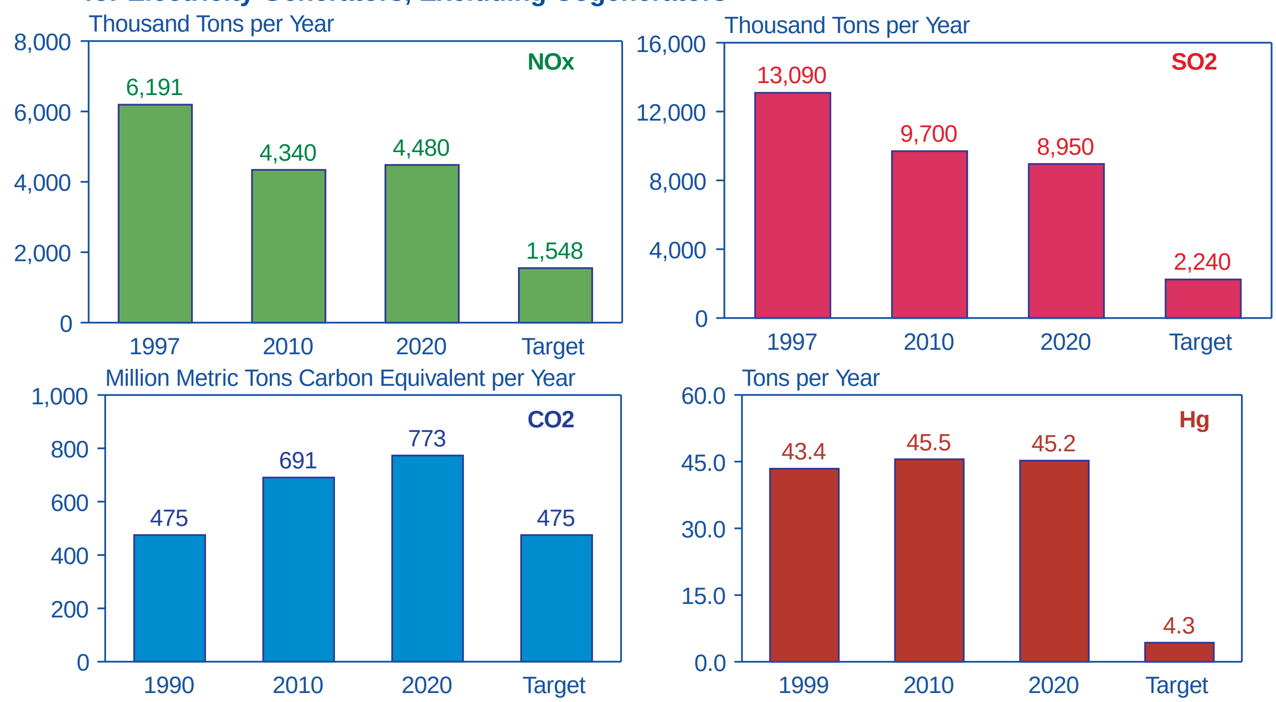
Currently, different environmental issues are being addressed through separate regulatory programs, many of which are undergoing modification. To control acid rain formation, CAAA90 required operators of electric power plants to reduce emissions of $SO_2$ and $NO_x$. Phase II of the $SO_2$ reduction program—reducing allowable $SO_2$ emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000. More stringent $NO_x$ emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of $SO_2$ and $NO_x$ contribute to the formation of regional haze, States could require that those emissions be reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in $NO_x$ and $SO_2$.

To reduce ozone formation, the U.S. Environmental Protection Agency (EPA) has promulgated a multi-State summer season cap on power plant $NO_x$ emissions that will take effect in 2004. Emissions of fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are associated with power plant emissions of $NO_x$ and $SO_2$, and further reductions in $NO_x$ and $SO_2$ emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced. Furthermore, if the United States decides to reduce its emissions of greenhouse gases, it is likely that energy-related $CO_2$ emissions will have to be reduced as a part of that program (see box on page 4).

Because the timing and levels of emission reduction requirements being considered are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions.

The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of $SO_2$ and $NO_x$ standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing $SO_2$ and $NO_x$ today may not be the optimal choice in the future if Hg and $CO_2$ emissions must also be reduced. Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that

**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.

reduces $SO_2$ and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence.

In both the previous and current Congresses, legislation has been proposed that would require simultaneous reductions of multiple emissions. Several bills were introduced in the 106th Congress to address these issues: S. 1369, the Clean Energy Act of 1999, introduced by Senator Jeffords; S. 1949, the Clean Power Plant and Modernization Act of 1999, introduced by Senator Leahy; H.R. 2900, the Clean Smokestacks Act of 1999, introduced by Congressman Waxman; H.R. 2645, the Consumer, Worker, and Environmental Protection Act of 1999, introduced by Congressman Kucinich; and H.R. 2980, the Clean Power Plant Act of 1999, introduced by Congressman Allen.

Additional bills introduced in the 107th Congress with similar goals include S. 556, the Clean Power Act of 2001, introduced by Senator Jeffords; H.R. 1256, the Clean

**Table 1. Description of the Analysis Cases**

| Case Name | Description | Emissions Limits |
|---|---|---|
| *CEF* business-as-usual | Reference case in the *CEF* report. Prepared using a revision of the *Annual Energy Outlook 1999* version of the National Energy Modeling System, which is known as *CEF*-NEMS. | Includes limits for $SO_2$ and $NO_x$ under CAAA90. |
| *CEF* moderate | Case in the *CEF* report adding the moderate *CEF* policies to the *CEF* business-as-usual case. Prepared using *CEF*-NEMS. | Includes limits for $SO_2$ and $NO_x$ under CAAA90. |
| *CEF* advanced | Case in the *CEF* report adding the advanced *CEF* policies to the *CEF* business-as-usual case. Prepared using *CEF*-NEMS. | Reduces $SO_2$ emissions from electricity generators in steps between 2010 and 2020 to 4.48 million tons to simulate a particulate reduction policy. Includes a domestic $CO_2$ trading system across all energy sectors, which is assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent. |
| Reference | EIA reference case for this analysis, incorporating some revisions to the *Annual Energy Outlook 2001* reference case. Prepared using NEMS. | Includes limits for $SO_2$ and $NO_x$ under CAAA90. |
| Reference with emissions limits | EIA case adding the emissions limits specified in the request for analysis to the above reference case. Prepared using NEMS. | Between 2002 and 2007, reduces $NO_x$ emissions from electricity generators to 75 percent below 1997 levels, Hg emissions to 90 percent below 1999 levels, $CO_2$ emissions to 1990 levels, and $SO_2$ emissions to 75 percent below the CAAA90 requirements. |
| Advanced technology | EIA case incorporating the *Annual Energy Outlook 2001* high technology assumptions for end-use demand, generation, and fossil fuel supply technologies to the reference case. Prepared using NEMS. | Includes limits for $SO_2$ and $NO_x$ under CAAA90. |
| Advanced technology with emissions limits | EIA case adding the emissions limits specified in the request for analysis to the above advanced technology case. Prepared using NEMS. | Between 2002 and 2007, reduces $NO_x$ emissions from electricity generators to 75 percent below 1997 levels, Hg emissions to 90 percent below 1999 levels, $CO_2$ emissions to 1990 levels, and $SO_2$ emissions to 75 percent below the CAAA90 requirements. |
| *CEF-JL* moderate | EIA case incorporating the moderate *CEF* policies in the reference case. Prepared using NEMS. | Includes limits for $SO_2$ and $NO_x$ under CAAA90. |
| *CEF-JL* moderate with emissions limits | EIA case adding the emissions limits specified in the request for analysis to the above *CEF-JL* moderate case. Prepared using NEMS. | Between 2002 and 2007, reduces $NO_x$ emissions from electricity generators to 75 percent below 1997 levels, Hg emissions to 90 percent below 1999 levels, $CO_2$ emissions to 1990 levels, and $SO_2$ emissions to 75 percent below the CAAA90 requirements. |
| *CEF-JL* advanced | EIA case incorporating the advanced *CEF* policies in the reference case. Prepared using NEMS. | Reduces $SO_2$ emissions from electricity generators in steps between 2010 and 2020 to 4.48 million tons to simulate a particulate reduction policy. Includes a domestic $CO_2$ trading system across all energy sectors, which is assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent. |
| *CEF-JL* advanced with emissions limits | EIA case adding the emissions limits specified in the request for analysis to the above *CEF-JL* advanced case. Prepared using NEMS. | Between 2002 and 2007, reduces $NO_x$ emissions from electricity generators to 75 percent below 1997 levels, Hg emissions to 90 percent below 1999 levels, $CO_2$ emissions to 1990 levels, and $SO_2$ emissions to 75 percent below the CAAA90 requirements. Includes a domestic $CO_2$ trading system across all energy sectors, which is assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent. |

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

Smokestacks Act of 2001, introduced by Congressman Waxman; and H.R. 1335, the Clean Power Plant Act of 2001, introduced by Congressman Allen. Each of the bills introduced in the 106th and 107th Congresses contains provisions to reduce power plant emissions of $NO_x$, $SO_2$, $CO_2$, and Hg over the next decade. The bills use different approaches—traditional technology-specific emission standards, generation performance standards, explicit emission caps with trading programs, or combinations of the three—but all call for significant reductions. In addition, the Bush Administration's National Energy Policy recommends the establishment of "mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides and mercury."[6] While differences exist on what the appropriate emissions limits should be and how the

### Representation of New Environmental Rules and Regulations

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; the implementation of new National Ambient Air Quality Standards (NAAQS) for fine particulates, which is 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 outcome of ongoing studies of the need to reduce power plant Hg emissions[a] or the resolution of lawsuits against the owners of coal-fired power plants accused of violating the Clean Air Act (CAA).

In June 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 power plants, but the degree to which they will be affected is not known. Power plant emissions of $SO_2$ and $NO_x$, which contribute to the formation of regional haze, may have to be reduced to improve visibility in some areas. The regulations call for States to establish goals and design plans for improving the visibility in affected areas; however, State implementation plans (SIPs) are not required until 2004 or later and therefore are not represented in this analysis, because they have not yet been promulgated.

The revised NAAQS, issued by the EPA in 1997, created a standard for fine particles smaller than 2.5 micrometers in diameter ($PM_{2.5}$). As with regional haze, power plant emissions of $SO_2$ and $NO_x$ are a component of fine particulate emissions. At the request of the President (memorandum July 16, 1997), the EPA is now reviewing scientific data on fine particulate emissions to determine whether to revise or maintain the standard. The review is expected to be completed in 2002. If the standard is maintained, States will be required to submit plans to comply by 2005.

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. However, the President has indicated that the United States will not support the approach called for in the Protocol. At this time, while 39 countries have ratified the protocol, only one Annex I (developed) country, Romania, has ratified the agreement. In addition, various elements of the Protocol are still under negotiation.

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 Hg, 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 their 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 the emissions standards for new power 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 the required emissions control equipment. The continued pursuit and outcome of these cases is uncertain at this time.

[a]On December 15, 2000, the EPA announced that Hg emissions need to be reduced, and that regulations will be issued by 2004.

[6]President George W. Bush, *National Energy Policy: Report of the National Energy Policy Development Group* (Washington, DC, May 2001).

program should be implemented, it is generally agreed that a more coordinated emission reduction policy is worth pursuing.

The analysis presented in this report is an examination of the impacts on energy markets that might result from steps taken by power suppliers to meet the emission limits specified in the request, given varying levels of energy demand. The potential benefits of reduced emissions—such as those that might be associated with reduced health care costs—are not addressed, because EIA does not have expertise in this area. It is important to realize that there are numerous policy instruments available for reducing emissions, i.e., technology standards, percentage reduction requirements, emission taxes, no-cost emission allowance allocation with cap and trade, emission allowance auction with cap and trade, and annual generation performance standard emission allowance allocation with cap and trade. Each of these approaches has different implications for the resource cost, price, and economic impacts of the emission reduction program. In general, an efficient cap and

### *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*

The EIA report *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, Mercury and a Renewable Portfolio Standard* was released in July 2001, in response to a request from the Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform. The Subcommittee requested that EIA analyze the impacts of coordinated efforts to reduce power plant emissions of $NO_x$, $SO_2$, $CO_2$, and Hg together with a 20-percent renewable portfolio standard. The analysis was prepared in two parts. The first part, which analyzed $NO_x$, $SO_2$, and $CO_2$, was released in December 2000. The report released in July 2001 extended the analysis to include the impacts of Hg emission reductions and the renewable portfolio standard.

The July 2001 EIA report examined the impact of the proposed emissions requirements on fuel use by electricity generators, capacity expansion and retirement decisions, electricity prices, and consumer demand for electricity. It also included discussion of the price and supply impacts on coal, natural gas, and renewable technologies. As requested by the Subcommittee, cases were prepared to examine the impacts of Hg emissions targets and a renewable portfolio standard separately, as well as when all of the emissions limits were combined with the standard. The "integrated cases" included cases reducing $CO_2$ emissions to 1990 levels and to 7 percent below 1990 levels. The key findings of the analysis included the following:

- Reducing $NO_x$ and $SO_2$ emissions in the electricity generation sector to 75 percent below their 1997 levels is projected to lead to the installation of a large amount of pollution control equipment with little change in fuel use for electricity generation. The power suppliers are projected to incur significant expenditures, but electricity prices are expected to be only slightly higher than the reference case level.
- Reducing Hg emissions by electricity generators to 90 percent below their 1997 level is projected to lead to the installation of a large amount of pollution-control equipment. The cost and price impacts of reducing the Hg emissions are projected to be larger than those of reducing $NO_x$ or $SO_2$ emissions.
- There is considerable uncertainty regarding the cost and performance of Hg control technologies due to the lack of sufficient full-scale tests on existing generating units.
- The projected impacts of a limit on $CO_2$ emissions from electricity generators that is 7 percent below 1990 levels dominate the impacts of limits on other emissions. The key compliance strategy in the cases that include $CO_2$ emissions reductions is expected to be a large shift from coal to natural gas and, to a lesser extent, renewables and nuclear power as fewer existing nuclear plants are retired.[a] Consumers are also expected to reduce their use of electricity in response to higher electricity prices.
- The imposition of a 20-percent renewable portfolio standard is projected to cause electricity generators to moderate the growth in their use of natural gas and, to a lesser extent, coal. Biomass, wind, and geothermal resources are projected to provide most of the required increase in renewable generation.
- Combining a 20-percent renewable portfolio standard with limits on $NO_x$ (75 percent below 1997), $SO_2$ (75 percent below 1997), Hg (90 percent below 1997), and $CO_2$ emissions (7 percent below 1990) is projected to reduce the shift to natural gas as a fuel for electricity generation and increase the use of renewable fuels.

[a]In accordance with the Subcommittee request, this study assumed that there would be no construction of new nuclear plants.

trade program is expected to lead to the lowest resource cost of compliance.[7]

The specific design of the cases, in terms of the timing, emissions limits, and technology assumptions, is important and should be kept in mind when the results are reviewed. Unlike the previous EIA reports on multi-emissions limits, all the cases specified in this request require the same timing and levels for the four emissions. The differences among the cases are additional assumptions, policies, and programs that encourage more rapid technology development and the adoption and penetration of more energy-efficient and renewable energy technologies. All the analysis cases assume that market participants—power suppliers, consumers, and coal, natural gas, and renewable fuel suppliers—would

### Reducing $NO_x$ and Hg Emissions

Considerable uncertainty exists about the ability of various types of emissions control equipment to remove Hg and, to a lesser extent, $NO_x$. Many factors affect the level of Hg emissions from a particular power plant, 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. 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.

Data collected by the Environmental Protection Agency in 1999 showed considerable variation in the content of Hg in the coal used by power plants and in the amount of Hg that was removed by the existing equipment at those power plants. On average the sample data show that the Hg content of coal shipped in 1999 was 7.3 pounds per trillion British thermal units (Btu), or 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 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. The 1999 data 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 noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment—on Hg emissions. Although many plant owners plan to add them in the near future, only a few are using them now. With respect to $NO_x$, SCRs are assumed to reduce emissions by 75 to 80 percent on average; however, because so few plants have SCRs today, the true cost and performance of the technology are not known at this time. With respect to Hg, this study assumes that, when combined with an $SO_2$ scrubber, an SCR enhances Hg removal with an emissions modification factor of 0.65 (increases Hg removal by 35 percent); however, no additional removal is assumed for plant configurations that have an SCR but do not have an $SO_2$ scrubber. Some pilot-scale tests suggest that SCRs would increase Hg removal for some system configurations, but the magnitude of the impact is not known at this time.

[7]For an analysis of the potential impacts of different emission allowance approaches, see D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, *The Effect of Allowance Allocation on the Cost of Carbon Emission Trading* (Washington, DC: Resources for the Future, August 2001); and C. Fischer, *Rebating Environmental Policy Revenues: Output-Based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, July 2001). For an analysis of the impacts of a generation performance standard, see Energy Information Administration, *Power Plant Emissions Reductions Using a Generation Performance Standard* (Washington, DC, May 2001), web site www.eia.doe.gov/oiaf/servicerpt/gps/gpsstudy.html.

become aware of impending emission limits before their start dates and would begin to take action accordingly. If it had been assumed that market participants would not anticipate the emission limits, the results would be different. In an earlier EIA study that looked at alternative program start dates for imposing a $CO_2$ emissions limit, an earlier start date and longer phase-in period were found to smooth the transition of the economy.[8]

This study is not intended to be an analysis of any of the specific congressional bills that have been proposed, and the impacts estimated here should not be considered as representing the consequences of specific legislative proposals. All the congressional proposals include provisions other than the emissions limits studied in this analysis, and several would use different policy instruments to meet the emissions limits. Moreover, some of the actions projected to be taken to meet the emissions limits in this analysis may eventually be required as a result of ongoing environmental programs whose requirements currently are not fully specified. The purpose of this report is to respond to the specific request by Senators Jeffords and Lieberman.

# The National Energy Modeling System and the *Annual Energy Outlook 2001*

## The National Energy Modeling System

The projections in this report were developed using NEMS, an energy-economy modeling system of U.S. energy markets, which is designed, implemented, and maintained by EIA and used annually to produce the projections in EIA's *Annual Energy Outlook*. NEMS is also used to analyze the effects of existing and proposed laws, regulations, and standards related to energy production and use; the impacts of new and advanced energy technologies; the savings from higher energy efficiency; the impacts of energy tax policy on the U.S. economy and energy system; and the impacts of environmental policies. Special analyses of these and other topics are performed at the request of the U.S. Congress, other offices in the U.S. Department of Energy (DOE), and other government agencies.

In NEMS, the production, imports, conversion, consumption, and prices of energy are projected for each year through 2020, subject to assumptions on 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. NEMS is a fully integrated framework, capturing the interactions of energy supply, demand, and prices across all fuels and all sectors of U.S. energy markets.

Within NEMS, four end-use demand modules represent energy consumption in the residential, commercial, industrial, and transportation sectors, subject to fuel prices, macroeconomic factors, and the characteristics of energy-using technologies in those sectors. The fuel supply and conversion modules represent the domestic production, imports, transportation, and conversion processes to meet the domestic and export demand for coal, petroleum products, natural gas, and electricity, accounting for resource base characteristics, industry infrastructure and technology, and world market conditions. The modules of NEMS interact to solve for the economic supply and demand balance for each fuel.

In order to capture regional differences in energy consumption patterns and resource availability, NEMS is a regional model. The end-use demand for energy is represented for each of the nine Census divisions. The supply and conversion modules use the North American Electric Reliability Council regions and subregions for electricity generation; aggregations of the Petroleum Administration for Defense Districts for refineries; and production regions specific to oil, natural gas, and coal supply and distribution.

NEMS incorporates interactions between the energy system and the economy and between domestic and world oil markets. Key macroeconomic variables, including the gross domestic product (GDP), disposable personal income, industrial output, housing starts, employment, and interest rates, drive energy consumption and investment decisions. In turn, changes in energy prices and energy activity affect economic activity, a feedback captured within NEMS. Also, an international energy module in NEMS represents world oil prices, production, and demand and the interactions between the domestic and world oil markets. Within this module, world oil prices and supplies respond to changes in U.S. demand and production.

A key feature of NEMS is the representation of technology and its improvement over time. The residential, commercial, transportation, electricity generation, and refining sectors of NEMS include explicit treatments of individual technologies and their characteristics, such as capital cost, operating cost, date of commercial availability, efficiency, and other characteristics specific to the sector. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment. In addition, in the electricity generation sector, fossil-fired and nuclear generating units can be retired before the end of their useful lives if

[8] Energy Information Administration, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999), web site www.eia.doe.gov/oiaf/kyoto3/kyoto3rpt.html.

it is more economical to bring on a replacement unit than to continue to operate the existing unit. Also, for new generating technologies, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind plants and for a decline in the costs as experience with the technologies is gained both domestically and internationally. Similar cost declines occur for the new end-use technologies.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is somewhat more limited due to limitations on the availability of data for individual technologies. In the industrial sector, technology improvement for the major processing steps of the energy-intensive industries is represented by technology possibility curves of efficiency improvements over time. In the oil and gas supply sector, technology progress for exploration and production activities is represented by trend-based improvements in success rates, finding rates, and costs. Productivity improvements over time represent technological progress in coal production.

Because of the detailed representation of capital stock vintaging and technology characteristics, NEMS captures the most significant factors that influence the turnover of energy-using and producing equipment and the choice of new technologies. New, more advanced technologies for buildings and equipment are generally characterized by the technology costs, performance, and availability, existing standards, and energy prices. Equipment that does not meet efficiency standards is not available as a choice. In all sectors, technology improvement occurs even in a reference case, because new, more efficient technology will be adopted as the demand for energy services increases and existing buildings and equipment are replaced. The characteristics of the technologies include initial dates of commercial availability of more advanced technologies as well as changes in efficiencies and costs that are assumed to occur in the future.

Past improvements in energy efficiency have resulted in part from efficiency standards that are included in the analysis; future efficiency standards assumed are those approved standards with specified efficiency levels. New or tightened efficiency standards could reduce the demand for energy, but stock turnover would still limit the speed of penetration. Standards have also been suggested to encourage the use of renewable fuels for electricity generation; however, proposed and possible future standards, legislation, and programs are not included in the analysis.

Although more efficient technologies may reduce energy consumption and energy expenditures, they are typically more expensive to purchase. Even if the full life-cycle cost of purchasing and operating a new, more efficient appliance is less than the life-cycle cost of a less efficient appliance, many consumers appear to be more concerned with the initial cost of an appliance when making the purchase. Higher energy prices may accelerate the adoption of more efficient technologies; however, higher purchase costs for more efficient technologies tend to slow their adoption. Hurdle rates represent this tendency of consumers to consider the first costs of new equipment.

Although prices play a role in consumers' decisions on energy-consuming equipment, there are other factors that come into play. Consumers tend to make decisions based on a number of personal preferences and lifestyle choices, in which energy prices may be only a part of the decisionmaking process. Preferences for larger televisions or higher horsepower vehicles are examples of factors that may outweigh energy costs. As another example, in the residential sector, home rental instead of purchase and frequent moving tend to lower the incentive to invest in more energy-efficient equipment. Information also has a major role in consumer decisions and will likely continue to do so in the adoption of new, more advanced technologies. Particularly when a more efficient or alternatively fueled technology carries a significantly higher cost or has different operational characteristics than more conventional technologies, information on the benefits of the new technology will be key to its adoption and penetration. Ultimately, the success of a given technology will depend not on the behavior of the marginal consumer, who may be particularly cost-conscious or innovative, but on the behavior of the average consumer, whose decision rests on a number of considerations.

Technology improvements, even when adopted in the market, may not necessarily lead to reductions in energy demand. In the transportation sector, for example, the use of more advanced technologies that could improve vehicle efficiency has been offset by increasing demand for larger and higher horsepower vehicles. To the extent that energy prices are a factor in consumer decisions, efficiency improvements may also increase energy demand. Efficiency gains may lower the cost of driving or operating other equipment, perhaps encouraging more travel, larger homes, and purchases of more equipment and increasing the demand for energy services.

## *Annual Energy Outlook 2001*

In accordance with the request from Senators Jeffords and Lieberman, this study is based on the reference case of *AEO2001*. Because EIA's reference case projections are required to be policy-neutral, the *AEO2001* projections generally assume that all Federal, State, and local law, regulations, policies, and standards in effect as of July 1, 2000, will remain unchanged through 2020. Potential impacts of pending or proposed legislation, proposed standards, legislation or regulations for which all specifics were not yet defined, or sections of existing legislation for which funds had not been appropriated prior to the preparation of *AEO2001* are not included in the projections. As a result, new regulations for diesel fuel and the new equipment efficiency standards announced in January 2001 are not included in the *AEO2001* projections. *AEO2001* assumes the continuation of the ethanol tax incentive through 2020. *AEO2001* also assumes that State taxes on gasoline, diesel, jet fuel, methanol, and ethanol will increase with inflation and that Federal taxes on those fuels will continue at 1999 levels in nominal terms. Although these taxes and tax incentives include clauses that limit their duration, they have been extended historically, and *AEO2001* assumes their continuation throughout the forecast. In general, the *AEO2001* projections include the most current data available as of July 31, 2000.

In the electricity generation sector, *AEO2001* includes the requirements of the CAAA90 to reduce $SO_2$ emissions to 8.95 million tons by 2010 and to meet new boiler standards for $NO_x$. *AEO2001* also represents the provisions of the $NO_x$ State Implementation Plan call in the 19 States where $NO_x$ caps have been finalized. Those $NO_x$ constraints begin in 2004 and are for the summer season only. Regulations that are not in place or are without specific guidelines are not included in *AEO2001*. In the electricity sector, these include new regulations for regional haze, which may affect electricity generators, but for which the State implementation plans are not required until 2004 or later, and new National Ambient Air Quality Standards for particulates, which are still being reviewed by the EPA and the courts. In addition, Hg emission reductions that may be required in the future by the EPA, which has announced that regulations will be issued by 2004, are not incorporated because they have not been finalized.

*AEO2001* projects that the U.S. economy, measured by real GDP, will grow at an average annual rate of 3.0 percent from 1999 through 2020. In *AEO2001*, both world oil prices and domestic natural gas prices are projected to decline over the next several years from their current high levels before gradually increasing in response to rising demand. Due to continued technological improvement in the production of oil and the expansion of production capability worldwide, the world oil price is expected to reach $22.41 per barrel in 2020 in real, inflation-adjusted 1999 dollars. With technological advances in the exploration and production of natural gas, the average wellhead price is projected to be $3.13 per thousand cubic feet in 2020. The average price of coal declines throughout the projection period due to increasing productivity in coal production and the expansion of production from lower-cost western sources.

The *AEO2001* projections assume a transition to full competitive pricing of electricity in States with specific deregulation plans—California, New York, New England, the Mid-Atlantic States, Illinois, Texas, Oklahoma, Michigan, Ohio, Arizona, New Mexico, and West Virginia. Other States are assumed to continue cost-of-service electricity pricing. A transition from regulated to competitive prices over a 10-year period from the beginning of restructuring in each region, and implementation of the provisions of California legislation regarding price caps, are assumed. Increased competition in electricity markets is also represented through assumed changes in the financial structure of the industry and efficiency and operating improvements that reduce operating and maintenance, administrative, and other costs. With these assumptions and declining coal prices, real average delivered electricity prices are projected to decline generally at an average annual rate of 0.5 percent between 1999 and 2020.

Electricity demand is projected to increase at an average annual rate of 1.8 percent between 1999 and 2020, most rapidly in the residential and commercial sectors due to growth for computers, office equipment, and other electrical equipment and appliances. Electricity generation fueled by natural gas and coal is projected to increase through 2020 to meet growing demand for electricity and to offset the projected retirement of existing nuclear and fossil units. Excluding cogeneration, the share of natural gas generation is projected to increase from 11 percent in 1999 to 33 percent in 2020, and the coal share is projected to decline from 54 percent to 47 percent, because electricity industry restructuring favors the less capital-intensive and more efficient natural gas generation technologies. Retirements of nuclear plants in the forecast are based on the costs of continuing to operate existing plants compared with the cost of new generating capacity. Of the 97 gigawatts of nuclear capacity available in 1999, 26 gigawatts is projected to be retired by 2020, and no new plants are expected to be constructed by 2020. The use of renewable energy technologies for electricity generation is projected to grow slowly because of the relatively low costs of fossil-fired generation and because electricity restructuring favors less capital-intensive natural gas technologies over coal and baseload renewable technologies.

With decreases or moderate increases in the prices of energy and continued economic growth, total energy consumption in *AEO2001* is projected to increase at an average rate of 1.3 percent per year through 2020, reaching 127 quadrillion British thermal units (Btu). Consumption in all end-use sectors grows in the projections; however, demand in the transportation sector increases most rapidly, reflecting increased travel and slow improvement in vehicle efficiency. Primary energy intensity, measured as energy use per dollar of real

GDP, declines in the projections at an average annual rate of 1.6 percent. This rate is less than the 2.3-percent decline in energy intensity experienced between 1970 and 1986, when rapid price increases and a shift to less energy-intensive industries led to rapid improvements in energy intensity. However, the intensity decline is more rapid than the average decline in the late 1980s and 1990s, reflecting efficiency improvements and continued structural shifts in the economy, which reduce the role of energy-intensive manufacturing industries.

$CO_2$ emissions from energy combustion are projected to increase at an average rate of 1.4 percent per year in *AEO2001*, growing from 1,511 to 2,041 million metric tons carbon equivalent between 1999 and 2020. Continuing economic growth and increasing demand for energy services lead to the continued projected growth in emissions. The slow growth of renewable technologies and the decline of electricity generation from nuclear power plants also contribute to emissions increases.

## Revisions to the *AEO2001* Reference Case

In accordance with the request, this study is based on the version of NEMS used in *AEO2001*; however, a few updates have been incorporated for this study.

### Short-Term Energy Price Updates

In addition to the *Annual Energy Outlook*, EIA also publishes the *Short-Term Energy Outlook* (*STEO*), a national-level, quarterly projection of U.S. energy supply, demand, and prices. The short-term forecast, which projects energy markets through the end of the following calendar year, is updated monthly. At the time the projections for *AEO2001* were finalized, the short-term results from *AEO2001* were calibrated to the September 2000 *STEO*. World crude oil prices for 2000 are currently estimated at $27.72 per barrel, compared to $28.17 per barrel in *AEO2001*, converted to 2000 dollars. At this time, crude oil prices in 2001 are projected to be similar to those projected in *AEO2001*.

A more significant change has occurred in the projections for natural gas. Converting to nominal dollars, natural gas wellhead prices in *AEO2001* are projected to be about $3.40 and $3.50 per thousand cubic feet in 2000 and 2001, respectively. Natural gas prices have been revised in the version of NEMS used in this study, to about $3.60 and $4.75 per thousand cubic feet in 2000 and 2001, respectively. Natural gas consumption projections in *AEO2001* are 22.0 and 22.7 trillion cubic feet for 2000 and 2001, respectively. Consumption is now estimated at higher levels and is calibrated to the April 2001 *STEO*, resulting in natural gas consumption estimates of 23.0 and 23.3 trillion cubic feet in 2000 and 2001. In the longer term, natural gas wellhead prices are now projected to decline at a slower rate through the next decade than in *AEO2001* and are projected in this study to rise to $3.10 per thousand cubic feet in 2020, similar to the projection of $3.13 per thousand cubic feet in *AEO2001* (both in real 1999 dollars). Total natural gas consumption is projected to be slightly higher, reaching 35.0 trillion cubic feet in 2020, as compared with 34.7 trillion cubic feet in *AEO2001*.

### New Equipment Standards

New equipment standards were issued by DOE in January 2001 and revised by the Bush Administration. Because the standards were not finalized when the projections for *AEO2001* were completed, they are not incorporated in the *AEO2001* projections. The new standards have been incorporated in all of the cases in this study, as shown in Table 2. Incorporating these standards reduces the projected demand for electricity and natural gas after 2004, particularly in the residential sector. Projected impacts on commercial energy consumption are small.

### Electricity Revisions for Emissions Modeling and Data Updates

*AEO2001* incorporates current regulations for emissions of $SO_2$ and $NO_x$ by electricity generators. However, in order to examine multi-emissions reduction strategies,

**Table 2. Appliance Standards Assumed in This Study**

| Product | Old Standard | New Standard | Effective Date |
|---|---|---|---|
| Residential natural gas water heaters | 0.54 EF | 0.59 EF | 2004 |
| Residential electric water heaters | 0.86 EF | 0.90 EF | 2004 |
| Residential central air conditioners | 10 SEER | 12 SEER | 2006 |
| Residential clothes washers | 0.817 MEF | 1.04/1.26 MEF | 2004/2007 |
| Commercial water-cooled air conditioners | 9.3 EER | 12.0 EER | 2003 |
| Commercial natural gas furnaces | 0.80 TE<br>1.5 percent casing losses | 0.80 TE<br>0.75 percent casing losses | 2003 |
| Commercial natural gas water heaters | 0.78 TE | 0.80 TE | 2003 |

Note: EF is energy factor (Btu out per Btu in); SEER is seasonal energy efficiency ratio (Btu out per watthour in); MEF is modified energy factor (cubic foot per kilowatthour per cycle); EER is energy efficiency ratio (Btu out per watthour in); TE is thermal efficiency (Btu out per Btu in). For commercial cooling equipment, a representative level is shown. Standards for these products vary by size and type of equipment.

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

the electricity market module (EMM) of NEMS has been revised to evaluate the impacts of limits on Hg emissions. Potential strategies for reducing Hg emissions include reducing electricity demand, switching to coal types with lower Hg content, installing control equipment, and switching to other fuels, such as natural gas, with little or no Hg content. Changes in electricity demand due to limits on Hg emissions could occur as the costs of compliance result in higher electricity prices. The coal market module (CMM) of NEMS evaluates switching to different coal types in order to reduce Hg emissions. EMM evaluates options to retrofit pollution control equipment and switch fuels in order to achieve Hg emissions limits.

Planning decisions to reduce Hg emission rates at coal-fired plants involve a variety of pollution control equipment. Control devices for $SO_2$ and $NO_x$ can also affect Hg emissions. Therefore, EMM has been revised since *AEO2001* to specify coal-fired plants according to the type of scrubber (wet, dry, or none) and $NO_x$ controls (low-$NO_x$ burners, selective catalytic reduction, selective noncatalytic reduction, or none). Also, EMM now represents additional equipment, such as spray cooling and fabric filters, that can also reduce Hg emissions with activated carbon injection. This expanded representation of coal-fired plant types considers planning decisions to use control devices for individual or combinations of pollutants.

In addition to constructing plants with emissions control equipment, Hg emissions can also be limited by switching from coal to other fuels with lower emission rates. Within EMM, available plants are dispatched according to their variable costs, which include fuel, operating and maintenance, and emissions costs. The emissions component has been revised to include the Hg allowance cost, i.e., the product of the resulting Hg emissions and the allowance price, in addition to the $SO_2$ and $NO_x$ allowance costs. Imposing a limit on Hg emissions could revise the dispatch order if a plant with lower fuel costs but higher emissions costs, such as coal, becomes less economic than a plant with higher fuel costs but lower emissions costs, such as natural gas.

CAAA90 currently provides limits on $NO_x$ emission rates for generating units, which depend on the type of boiler. Additional restrictions on $NO_x$ emissions are specified for selected eastern States during the summer months. Since *AEO2001*, EMM has been revised to consider simultaneously a national, annual limit on $NO_x$ emissions that is similar to the "cap and trade" system that limits $SO_2$ emissions under CAAA90. Because it is assumed that proposed regulations to reduce $SO_2$ emissions further would incorporate the current trading system, no additional modifications were required.

Updates to available generating capacity have also been incorporated since *AEO2001*. Units previously unreported to EIA that began operation in 1999 and 2000 are now included in the existing capacity. Most of these units use natural gas, which produces fewer emissions than coal- or petroleum-fired capacity. Expected additions of renewable generating capacity in 2000 and 2001 have also been increased, primarily as a result of State mandates, as noted below. Finally, the projected capacity mix incorporates future installations of pollution control equipment and conversions of plants resulting from the settlement of lawsuits between some electricity generators and the EPA.

### Revisions to Renewables Data and Assumptions

*AEO2001* incorporates near-term projections for known new renewable energy capacity resulting from State mandates and voluntary programs, totaling 5.4 gigawatts by 2020, 3.1 gigawatts of which were from wind power. For this study, estimates of geothermal and wind power have been updated to account for additional announced units and accelerated completions for units that are expected after 2001 in *AEO2001*. As a result, 7.5 gigawatts of additional planned capacity is now included by 2020, 5.1 gigawatts of which is wind capacity.

*AEO2001* assumptions include estimates of geothermal resource supply from 51 known geothermal resource areas in the United States; however, it is unlikely that most of the geothermal resources at many new untested sites would be used before 2020. Instead, much smaller installations would be built first, with expansion moving more slowly as additional units prove successful. Furthermore, the *AEO2001* estimates do not account for environmental, market, and other limitations likely to constrain development at many sites. Therefore, for this study, estimates of geothermal resources have been reduced from nearly 47 gigawatts in *AEO2001* to about 28 gigawatts, to provide a more accurate representation of likely development opportunities through 2020. As a result, the cost of geothermal energy is generally higher, and the total quantity of geothermal supply is lower than in *AEO2001*.

Because wind and solar power are intermittent sources of electricity generation, *AEO2001* assumes that no more than 12 percent of the annual generation in any region could be provided by these sources in order to avoid electric power system disturbances. However, based on research done by the National Renewable Energy Laboratory and more recent experience, this assumed limit has been raised to 15 percent for the reference and advanced technology cases but is not a binding limit.[9]

[9]Y.H. Wan and B.K. Parsons, *Factors Relevant to Utility Integration of Intermittent Renewable Technologies*, NREL / TP-463-4953 (Golden, CO: National Renewable Energy Laboratory, August 1993).

As assumed in the *CEF* analysis, the limit is removed in the cases that incorporate the *CEF* policies. The limit would not have been a constraint in the case with the moderate *CEF* policies. In the case incorporating the advanced *CEF* policies, the limit would have been binding for the Upper Great Plains and Rocky Mountain / Southwest regions.

In order to account for short-term supply bottlenecks, the *AEO2001* version of NEMS assumes that, if the national capacity of any renewable generating technology increases by more than 30 percent in one year, the overnight capital cost for that technology would increase by 0.5 percent for each 1-percent capacity increase over 30 percent. Recognizing large worldwide growth for major renewable energy technologies and increased ability to meet demand growth in any country, the threshold has been increased from 30 percent to 50 percent in this study.

### Modifications to Coal Production Data and Assumptions

Similar to EMM, revisions have been made to CMM following the *AEO2001* in order to add the capability to evaluate the impacts of Hg emissions limits at U.S. coal-fired power plants. An annual constraint on Hg emissions within CMM and the assignment of an average Hg content for each of the 35 coal supply sources represented in CMM have both been incorporated. The Hg emissions factors in CMM range from a low of 2.04 pounds Hg per trillion Btu for low-sulfur subbituminous coal originating from mines in the Rocky Mountain supply region (Colorado and Utah) to 63.90 pounds Hg per trillion Btu for waste coal originating from sites in Northern Appalachia (Pennsylvania, Ohio, northern West Virginia, and Maryland).[10]

An additional revision made to CMM concerns the size and duration of existing contracts between coal suppliers and electricity generators. In the cases with emissions limits in this analysis, all coal supply contracts are assumed to be phased out by 2003, reflecting the assumption that the accelerated and more stringent emission restrictions would constitute sufficient justification to end contracts under *force majeure* measures.

# Scenarios for a Clean Energy Future

## Background

*CEF* was commissioned by DOE's Office of Energy Efficiency and Renewable Energy. The report was prepared by an interlaboratory working group from Argonne National Laboratory, Lawrence Berkeley National Laboratory, the National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory.

The purpose of *CEF* was to analyze the impacts of various energy policies and programs that would promote "clean energy technologies," which include reducing the energy intensity of the economy, reducing the $CO_2$ intensity of the energy used, and integrating the sequestration of $CO_2$ into energy production and delivery. According to the *CEF* working group, the collection of policies was developed to address key energy issues such as emissions, oil import dependency, and energy and economic efficiency. The policies, which are listed in Chapter 3 of this report, include fiscal incentives, voluntary programs, regulations, and research and development.

*CEF* analyzed business-as-usual, moderate, and advanced cases. The business-as-usual case assumed current energy policies and programs as of the time *CEF* was prepared, as well as continued technological improvement. It was based on the reference case from the *Annual Energy Outlook 1999* (*AEO99*), the most recent *Annual Energy Outlook* available at the time the *CEF* analysis was initiated.[11] As discussed later, a number of significant modifications have been introduced into NEMS since *AEO99*, including, for example, higher projections of economic growth and electricity demand, which lead to higher energy demand and $CO_2$ emissions.

The moderate and advanced cases in *CEF* included energy policies and programs to address the energy issues noted above, which can include new programs or extensions of existing programs. In general, the advanced case included additional or extended programs relative to the moderate case. The advanced case also included a domestic $CO_2$ trading system that was assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent. Additional sensitivities were presented in the report, including cases with higher natural gas and petroleum prices, a shorter life for a proposed renewable portfolio standard, higher costs for renewable technologies, higher costs of advanced fossil-fired generating technologies, no diesel penetration in light-duty vehicles, and a carbon fee of $25 per metric ton carbon equivalent; however, these sensitivities were not the primary results of the study. Most of the sensitivities were designed to analyze some key uncertainties in the analysis as identified by the *CEF* working group.

The *CEF* study followed an earlier report, *Scenarios of U.S. Carbon Reductions*, published by an interlaboratory

[10]U.S. Environmental Protection Agency, Emissions Standards Division, *Information Collection Request for Electric Utility Steam Generating Units, Mercury Emissions Collection Effort* (Research Triangle Park, NC, 1999).

[11]Energy Information Administration, *Annual Energy Outlook 1999*, DOE / EIA-0383(99) (Washington, DC, December 1998), web site www.eia.doe.gov / oiaf / archive / aeo99 / homepage.html.

working group in 1997.[12] The earlier report outlined and analyzed technologies to reduce energy consumption and $CO_2$ emissions, looking at the individual energy sectors separately. According to the *CEF* authors, *CEF* differed from the prior study by examining the policies and programs that would encourage the adoption and penetration of clean energy technologies. Also, *CEF* included an integrated analysis to assess the impacts of certain changes in one energy sector throughout the energy system—for example, the impact of lower electricity demand on the requirements for electricity generation or the impact of changes in fuel demand on prices. In some cases, *CEF* used a revised version of the *AEO99* version of NEMS, referred to as *CEF*-NEMS, to implement the *CEF* policies directly. In many cases, the policies were analyzed separately, and the results were incorporated in *CEF*-NEMS, using the modeling system as an accounting system to capture the intersectoral impacts.

## *CEF* Revisions to the *AEO99* Reference Case

The *CEF* working group developed a revised version of NEMS, referred to as *CEF*-NEMS, which was based on the NEMS version used for *AEO99*. According to the *CEF* authors, the following revisions were made to the *AEO99* model and assumptions.

In the industrial demand sector, the baseline energy intensities were revised in *CEF* for three of the energy-intensive industries—paper and pulp, cement, and steel—and the rate of improvement in the energy intensity of those three industries was accelerated relative to the rate of improvement assumed in *AEO99*. Since the version of NEMS used for *AEO2001*, as well as *AEO99*, is calibrated to the 1994 Manufacturing Energy Consumption Survey, no changes were made to these baseline data for this study. The retirement rates of equipment in all industries were revised to reflect an assessment of shorter equipment life. These revisions were typically quite small, and some revised rates have been incorporated in NEMS since *AEO99*. As a result of these modifications, projected primary energy consumption for the industrial sector in *CEF* was approximately 1 quadrillion Btu lower in 2020 than the 42.1 quadrillion Btu projected in *AEO99*.

Four sets of changes were made to the *AEO99* reference case assumptions in the electricity market module of *CEF*-NEMS. First, co-firing of biomass in coal plants was incorporated, which is a feature later added to NEMS by EIA. Second, modifications were made in *CEF*-NEMS to certain costs applied to wind generation. *AEO99* assumed decreasing capital costs for wind generation technology due to learning effects as more units are built but higher resource costs once low-cost wind resources were used, to reflect decreasing quality of available resources, transmission network upgrades, and alternative uses for land. In *CEF*-NEMS, these costs were reduced and regional limits on the growth in wind generation in a single year were removed, omitting some important costs necessary in evaluating wind supply. Although these modifications had little impact on the *CEF* business-as-usual case, they had a much larger impact on the moderate and advanced cases.

Third, *CEF*-NEMS removed a constraint on the expansion of geothermal generation. In *AEO99*, it was assumed that a new geothermal site was limited to 50 megawatts of capacity, with a 3-year delay before additional capacity could be built at that site, reflecting the geothermal industry practice of gradual site testing and phased commercial expansion. Although a 50-megawatt constraint may have been too restrictive for some sites, particularly in cases with a high demand for renewable technologies, removing the constraint altogether could result in unrealistic projections of geothermal builds.

Finally, the revision to the electricity generation assumptions that had the most impact on the results of the *CEF* business-as-usual case was to reduce the cost of nuclear plant refurbishment and relicensing. In *AEO99*, it was assumed that a charge of $150 per kilowatt would be required to operate a nuclear unit beyond 30 years of age for an additional 10 years. An additional charge of $250 per kilowatt would be required to operate a unit for 20 years past its current license expiration date of 40 years. These costs were designed to capture age-induced impacts on operating costs of the unit. At both steps of this cost evaluation, if the total costs of continuing to operate the unit were less than the costs of building new capacity, the unit would continue in operation. In *CEF*-NEMS, the 40-year charge was reduced to $50 per kilowatt. As a result, fewer nuclear plants were retired in the *CEF* business-as-usual case than in the *AEO99* reference case, reducing the need for additional capacity additions, which are largely fossil fuel fired, and making $CO_2$ emissions reductions easier in the *CEF* moderate and advanced cases.

In the *AEO99* reference case, nuclear capacity declined from 99 gigawatts in 1997 to 49 gigawatts in 2020; in the *CEF* business-as-usual case, nuclear capacity declined to 72 gigawatts. As a result, nuclear generation, which declined from 629 to 359 billion kilowatthours between 1997 and 2020 in *AEO99*, only declined to 520 billion kilowatthours in 2020 in the *CEF* business-as-usual case. Due to more nuclear and less fossil-fired generation,

[12]Interlaboratory Working Group, *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*, ORNL / CON-444 and LBNL-40533 (Oak Ridge National Laboratory, Oak Ridge, TN, and Lawrence Berkeley National Laboratory, Berkeley, CA, September 1997), web site www.ornl.gov / ORNL / Energy_Eff / labweb.htm.

electricity generator $CO_2$ emissions in the *CEF* business-as-usual case reached 709 million metric tons carbon equivalent, as compared with 746 million metric tons carbon equivalent in *AEO99*.

Since *AEO99*, the methodology for projecting nuclear retirements has been revised and aging-related cost assumptions have been lowered. In *AEO2001*, more gradual increases in annual expenditures due to aging are assumed, rather than a one-time investment, and mainly after 40 years of operation. From 30 to 40 years of age, the aging-related cost is assumed to increase by $0.25 per kilowatt per year; from age 40 to 50 an additional annual cost of $13.50 per kilowatt is assumed; and from age 50 to 60 an additional annual cost of $25 per kilowatt is assumed. In *AEO2001*, nuclear capacity is projected to be 72 gigawatts in 2020, the same as in *CEF*. In 2020, nuclear generation is projected to be 574 billion kilowatthours in *AEO2001*, with electricity generator $CO_2$ emissions of 772 million metric tons carbon equivalent. The higher projection for emissions is largely due to higher projected economic growth and electricity demand in *AEO2001*.

Total primary energy consumption in the *AEO99* reference case and the *CEF* business-as-usual case was projected to increase from 94 to 120 quadrillion Btu between 1997 and 2020. Primarily as a result of more nuclear generation, total projected $CO_2$ emissions in the *CEF* business-as-usual case reached 1,922 million metric tons carbon equivalent in 2020, as compared with 1,975 million metric tons carbon equivalent in the *AEO99* reference case. In *AEO2001*, total energy consumption in 2020 is projected to be 127 quadrillion Btu, with $CO_2$ emissions of 2,041 million metric tons carbon equivalent.

## Summary of Results in *CEF*

Many of the policies in *CEF*, which are enumerated in Chapter 3, were aimed at encouraging the adoption and penetration of more energy-efficient technologies. These included financial incentives, research and development, efficiency standards (which are important policies in the buildings sectors), and voluntary agreements and deployment programs. As requested, this analysis incorporates the same policies assumed by the *CEF* analysts where possible; however, several general issues are noted below that may call these assumptions into question:

- Many of the *CEF* policies are based on additional funding for technology research and development, totaling $1.4 billion (1997 dollars) per year in the moderate case and $2.8 billion per year in the advanced case, with the costs shared between the public and private sectors. These included most of the *CEF* transportation policies, the *CEF* policies for electricity generation technologies, and, to a lesser extent, the policies for technologies in the other end-use sectors. The impacts of research and development funding for new technologies, whether ongoing or incremental, are difficult to quantify. Some of the proposed funding for technology may achieve benefits only in a long time frame (beyond 2020) or may not achieve success at all, and predicting which technology development will be successful is highly speculative. A specific link cannot be established between levels of funding for research and development and specific improvements in the characteristics and availability of energy technologies. Because these funding increases are questionable and the link between funding and technology development is tenuous, the suggested technology improvements based on these research and development policies are also questionable. Although the environmental benefits of the advanced case would be higher than those of the moderate case, the associated costs would also be higher. The environmental benefits are not quantified.[13]

- Many *CEF* policies, particularly in the industrial sector, relied on voluntary and information programs. Similar to assessing the impact of increased research and development funding, it is also difficult to analyze the impacts of information programs, voluntary initiatives, and partnerships on realized technology development and deployment. Some voluntary programs appear to have achieved success. Although the benefits of past efforts are difficult to quantify, they are generally assumed in the efficiency trends in the reference case.

- Some of the *CEF* policies required legislative or regulatory actions that may not be enacted. These included tax credits for certain high-efficiency vehicles and renewable generation technologies, new equipment standards, national electricity industry restructuring, a renewable portfolio standard (which requires a specified percentage of electricity sales to be generated from renewable sources other than hydropower), new particulate standards, and pay-at-the-pump motor vehicle insurance. To the extent that these are not enacted or are enacted at later dates than assumed in *CEF*, the results of the *CEF* analysis would be altered.

[13] *CEF* estimated the research and development funding, plus program implementation, administrative, and incremental technology investment costs. Comparing those costs with reductions in energy expenditures, *CEF* concluded there would be a net saving. The present analysis does not estimate the costs of the *CEF* policies.

- Certain technology cost reductions in the *CEF* analysis appear unrealistic. For example, in the residential sector, the cost of the most efficient unit for some appliances was reduced to the cost of the least efficient unit. It seems unlikely that either research and development or voluntary programs could reduce technology costs to that level. Other technology assumptions also appear unrealistic—for example, the assumption that generating plants using $CO_2$ sequestration technology would achieve the same efficiency as those that do not.

- In the residential and commercial sectors, consumer hurdle rates were significantly reduced. These hurdle rates represent the willingness of consumers to invest in energy-efficient equipment. In practice, hurdle rates are often much higher than the cost of borrowing money, for reasons including transaction costs, a desire for equipment features other than efficiency, and builders or building owners who purchase the equipment but do not pay the energy bills. Although these hurdle rate reductions in the *CEF* analysis were attributed to voluntary programs and other policies, they appear to be optimistic in their valuation of consumer desire for energy efficiency, resulting in hurdle rates of 15 percent, which are less than the interest rates charged by many credit cards.

- In the *CEF* analysis, the growth rates for miscellaneous electricity uses in both the residential and commercial sectors were significantly reduced. Miscellaneous electricity uses consist of a variety of smaller end uses not individually identified in NEMS. Energy used by small heating elements, motors, and electronic devices comprises miscellaneous uses in the residential sector. In the commercial sector, miscellaneous electricity uses include a myriad of devices such as transformers, automated teller machines, traffic lights, telecommunications equipment, and medical equipment.[14] The modifications to miscellaneous electricity growth rates were largely attributed by the *CEF* authors to voluntary programs, State market transformation programs, and, in the advanced case, to a 2004 commercial transformer standard. The reductions in the growth rates appear unrealistic given the equipment in these categories, where it is unlikely that the use of the equipment will be greatly reduced. Although there is the potential for some efficiency improvements, it is unlikely that efficiencies could improve enough to reach the consumption levels achieved in *CEF*. Some of these small appliances include heating elements that cannot readily incorporate increased efficiency.

- From a macroeconomic perspective, the crucial assumption underlying the *CEF* study was that the economy currently is not using its resource base efficiently—i.e., that the economy is not on the production possibilities curve. The study assumed that overcoming large-scale market failures can place the economy on this frontier with less energy use and fewer emissions. However, many of the presumed market failures are actually rational, efficient decisions on the part of consumers given current technology, expected prices for energy and other goods and services, and the value they place on their time to evaluate options. As Henry Jacoby points out, "The key difference between market barriers and market failures is that correcting failures may sometimes produce a net benefit, whereas overcoming barriers always involves cost."[15]

As noted in Table 3, *CEF* projected lower energy consumption and $CO_2$ emissions in the business-as-usual case than in the *AEO2001* reference case, due to modifications to the *AEO99* reference case in the *CEF* analysis and to the changes in the model methodologies and assumptions, particularly the economic growth rates, in *AEO2001* relative to *AEO99*. *CEF* projected that the policies in the moderate case and the advanced case could further reduce total energy consumption by 8 percent and 19 percent, respectively, in 2020 relative to the business-as-usual case. In the advanced case, *CEF* projected that total energy consumption would increase at an average annual rate of 0.4 percent between 1997 and 2010 then decrease at an average annual rate of 0.3 percent between 2010 through 2020. Given growing population and a growing economy, an actual decrease in energy consumption as projected in *CEF* would appear unlikely without significant increases in energy prices. Total energy consumption in the *CEF* advanced case was projected to reach 99 quadrillion Btu in 2010, declining to 97 quadrillion Btu in 2020.

In 2020, the use of renewable energy was projected in the *CEF* analysis to be 11 percent higher and 27 percent higher in the moderate and advanced cases, respectively, than in the business-as-usual case. In the advanced case, renewable generation was encouraged by policies such as a renewable portfolio standard, a carbon fee of $50 per metric ton carbon equivalent, and a proposed extension of the production tax credit, which was applied only to wind and biomass in the moderate case, to all nonhydropower renewables. In both cases,

[14] Major uses of electricity include space heating, space cooling, water heating, refrigeration, cooking, and lighting in the residential sector. All of these uses plus ventilation and office equipment are specifically identified as end uses in the commercial sector. Miscellaneous uses include all other end uses.

[15] H. Jacoby, "The Uses and Misuses of Technology Development as a Component of Climate Change Policy," presentation to the America Council for Capital Formation, Center for Policy Research (October 1998).

*CEF* projected lower fossil fuel consumption and fewer nuclear power retirements. In *CEF*, natural gas consumption was projected to be lower in both cases than in the business-as-usual case and did not increase in the advanced case compared to the moderate case despite a sharp reduction in coal use, due to the greater use of renewables and nuclear power and projected efficiency improvements that reduce overall energy consumption.

In percentage terms, the projected reductions in $CO_2$ emissions that occurred in the *CEF* cases were greater than the reductions in energy consumption due to the shifts to less carbon-intensive fuels. In the moderate case, projected $CO_2$ emissions were 5 percent and 9 percent lower in 2010 and 2020, respectively, than in the business-as-usual case. However, emissions remained significantly higher than recent historical levels. Projected $CO_2$ emissions were reduced by 17 percent and 30 percent in 2010 and 2020, respectively, in the advanced case, compared to the business-as-usual case. In 2010, $CO_2$ emissions were projected to reach 1,463 million metric tons carbon equivalent in the advanced case, which is less than the 1997 level (estimated at 1,480 million metric tons carbon equivalent in *CEF* and now estimated at 1,493 million metric tons carbon equivalent in the *U.S. Carbon Dioxide Emissions from Energy Sources: 2000 Flash Estimate*[16]). By 2020 in the advanced case, *CEF* projected that $CO_2$ emissions would decline further to 1,347 million metric tons carbon equivalent, essentially the same as the level of 1,349 million metric tons carbon equivalent estimated for 1990.

Particularly in the advanced case, the largest reductions in $CO_2$ emissions, in percentage terms, occurred in the residential and commercial sectors due to increased energy efficiency and the use of less carbon-intensive fuels to generate the electricity used in those sectors. As noted above, however, the application of lower hurdle rates in the *CEF* analysis implicitly assumed changes in consumer buying practices that are unsupported by history. The transportation sector had the smallest percentage reductions in $CO_2$ emissions. Although efficiencies were assumed to improve for all modes of transportation, the transportation sector has limited ability to shift from its almost exclusive reliance on petroleum to other, less carbon-intensive fuels. Comparing the advanced case to the moderate case, the additional reductions in $CO_2$ emissions were largely due to policies in the advanced case that promoted less electricity generation from coal and more from natural gas, renewables, and nuclear power, including the $CO_2$ trading program, which increased prices for fossil fuels and for electricity delivered to customers.

## Representing the *CEF* Policies in NEMS

The request for this analysis to EIA specified that two cases be analyzed "assuming the moderate [advanced] supply and demand-side policy case of the Clean Energy Futures study." As noted earlier, however, *CEF* was based on the *AEO99* version of NEMS, and there

**Table 3. Energy Consumption and $CO_2$ Emissions in *AEO2001* and the *CEF* Cases, 2010 and 2020**

| Year | Projection | Primary Energy Consumption: Quadrillion Btu | Primary Energy Consumption: Percent Change From *CEF* Business-As-Usual | $CO_2$ Emissions[a]: Million Metric Tons Carbon Equivalent | $CO_2$ Emissions[a]: Percent Change From *CEF* Business-As-Usual |
|---|---|---|---|---|---|
| 1997 | — | 94.3 | — | 1,493 | — |
| 2000 | — | 98.5 | — | 1,558 | — |
| 2010 | *AEO2001*[b] | 114.1 | — | 1,809 | — |
| | *CEF* Business-As-Usual | 110.4 | — | 1,769 | — |
| | *CEF* Moderate | 106.5 | -4 | 1,684 | -5 |
| | *CEF* Advanced | 99.3 | -10 | 1,463 | -17 |
| 2020 | *AEO2001*[b] | 127.0 | — | 2,041 | — |
| | *CEF* Business-As-Usual | 119.8 | — | 1,922 | — |
| | *CEF* Moderate | 110.1 | -8 | 1,740 | -9 |
| | *CEF* Advanced | 96.8 | -19 | 1,347 | -30 |

[a]$CO_2$ emissions are from energy combustion only and do not include emissions from energy production or industrial processes.
[b]As noted in the letter of request in Appendix A, the *AEO2001* reference case is the starting point for this analysis.
Note: *AEO2001 = Annual Energy Outlook 2001*; Btu = British thermal unit; *CEF = Clean Energy Future*; $CO_2$ = carbon dioxide.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2000*, DOE/EIA-0384(2000) (Washington, DC, August 2001); EIA, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001)(Washington, DC, December 2000); EIA, *U.S. Carbon Dioxide Emissions from Energy Sources: 2000 Flash Estimate* (Washington, DC, June 2001), web site www.eia.doe.gov/oiaf/1605/flash/sld001.htm; Interlaboratory Working Group, *Scenarios for a Clean Energy Future*, ORNL/CON-476 and LBNL-44029 (Oak Ridge National Laboratory, Oak Ridge, TN, and Lawrence Berkeley National Laboratory, Berkeley, CA, November 2000), p. ES.5.

[16]Energy Information Administration, *U.S. Carbon Dioxide Emissions from Energy Sources: 2000 Flash Estimate* (Washington, DC, June 2001), web site www.eia.doe.gov/oiaf/1605/flash/sld001.htm.

have been significant changes to the model and to the assumptions for *AEO2000* and particularly *AEO2001*. Consequently, directly using the energy demands or the energy demand changes that occurred in *CEF* is not appropriate for this analysis.

One of the most significant changes between *AEO99* and *AEO2001* is the assumed rate of economic growth. In *AEO99*, the U.S. economy was projected to grow at an average annual rate of 2.0 percent between 1999 and 2020; however, the growth rate in *AEO2001* is projected to be 3.0 percent. Part of the upward revision to the growth rate that occurred in *AEO2001* is due to statistical and definitional changes in the National Income and Product Accounts; however, the projection also reflects a more optimistic view of long-run economic growth. The more rapid projected growth in GDP affects the projected growth in other key economic drivers—for example: commercial floorspace growth, 1.3 percent per year in *AEO2001* vs. 0.8 percent per year in *AEO99*; industrial gross output growth, 2.6 percent per year vs. 1.9 percent per year; and real disposable personal income growth, 3.0 percent per year vs. 2.3 percent per year.

In general, more rapid projected economic growth leads to increased demand for energy services and more energy consumption. In addition, the growth rate for electricity demand is reevaluated in *AEO2001*, particularly for computers, office and other electrical equipment and appliances, and miscellaneous energy uses, in accordance with recent trends. Electricity demand is projected to increase at an average annual rate of 1.8 percent between 1999 and 2020 in *AEO2001*, compared with an average of 1.4 percent projected in *AEO99*. In part due to higher economic growth but also as the result of a reestimation of projected light-duty vehicle travel, travel in *AEO2001* increases at an average annual rate of 1.9 percent from 1999 through 2020, as compared with 1.7 percent in *AEO99*. Overall, total energy consumption in *AEO2001* is projected to increase at an average annual rate of 1.3 percent from 1999 to 2020, as compared with an average annual rate of 1.0 percent in *AEO99*.

Partly offsetting the higher projected economic growth in *AEO2001* is more rapid improvement in energy intensity. In the commercial sector, the effects of Executive Order 13123, signed by President Clinton in June 1999, mandating reduced energy use in Federal facilities, and a new fluorescent ballast standard promulgated in September 2000 mitigate some of the previously expected growth in energy consumption. Improvements in industrial energy intensity are reevaluated in *AEO2001*. As a result, primary energy consumption per dollar of output in the industrial sector is projected to decrease at an average annual rate of 1.5 percent in *AEO2001*, compared with 1.1 percent in *AEO99*. Primary energy intensity of the U.S. economy is projected to decline at an average annual rate of 1.6 percent in *AEO2001*, compared with 1.0 percent in *AEO99*. On the other hand, starting with *AEO2001*, the size of new houses is projected to increase over time, in accordance with recent trends, which tends to increase the energy intensity of households. In 2020, the average home is 2 percent larger in the *AEO2001* projections than in *AEO99*.

Energy price projections have also been revised between *AEO99* and *AEO2001*. The most significant change is for natural gas prices. Converting the energy prices in *AEO99* to 1999 dollars as reported in *AEO2001*, projected natural gas wellhead prices in 2020 are higher by 13 percent in *AEO2001* and 12 percent in this study, in part due to higher projected demand for natural gas in *AEO2001*. Partly due to higher projected natural gas prices, the average delivered electricity price in 2020 is projected to be 3 percent higher in *AEO2001* than in *AEO99*. These price changes affect the economics of technology adoption and penetration. Projected world oil prices and minemouth coal prices in 2020 in *AEO2001* are similar to those in *AEO99*.

Other assumption changes also affect technology adoption. As an example, in the transportation demand module of NEMS, the assumed incremental cost of a hybrid electric vehicle relative to a conventional vehicle has been reduced from $13,600 in *AEO99* to $8,500 in *AEO2001*. The introduction date has also been advanced from 2003 to 2000, reflecting the commercialization of these vehicles.

Overall, these revisions to the reference case projections indicate that the demand impacts of improved technology assumptions, as reflected in *CEF* and based on *AEO99*, could not simply be applied to the *AEO2001* projections for the purposes of this analysis.

In some cases, the *CEF* policies overlap with or have been overtaken by changes that have occurred over time or within NEMS. For example, some policies were expected in the *CEF* analysis to be instituted in 2000 or 2001, which is no longer plausible. Also, residential equipment standards proposed in *CEF* are modified in this analysis to account for the standards announced in January 2001, as later modified by the Bush Administration. The January 2001 standards included a 13 SEER (seasonal energy efficiency ratio, calculated as Btu of output per watthour of input) for central air conditioners and heat pumps, which was revised by the current administration to 12 SEER, as assumed in this analysis. The revision is being challenged in court, and a final rulemaking is expected in early 2002.

Modeling enhancements have also been made to NEMS since the *AEO99* version, and several have a significant impact on the results. A few of the more significant examples are noted below:

- The representation of industrial and commercial cogeneration has been enhanced to include an explicit evaluation of the costs and performance of various cogeneration technologies.[17] In addition, a representation of distributed generation has been added to the electricity generation, residential, and commercial modules. Both economically based and program-driven installations are represented, as well as the projected effects on purchased electricity in the residential and commercial sectors and, for cogeneration, on fuel to meet space heating and water heating demand.

- In the residential module, the building shell methodology, which had been based in *AEO99* on an assumption of the improvement in new buildings over time, has been replaced by an explicit evaluation of the costs of various shell efficiency levels integrated with the choice of heating and air-conditioning equipment. As a result, policies aimed at improving residential shell efficiency cannot be addressed in the same fashion as in the *AEO99* version of NEMS.

- In the transportation module, light-duty vehicles are now represented by 20 rather than 10 vintages. The methodology for vehicle choice in *AEO2001* competes alternative-fueled and advanced technology vehicles directly with conventional vehicles. In *AEO99*, a generic alternative technology competed with conventional vehicles. Also, hybrid electric vehicles are no longer considered to be an advanced technology but, rather, another conventional technology.

- *AEO2001* includes a redesigned component for geothermal electricity generation with a methodology more similar to those of the other renewable technologies, providing a comparable evaluation of the potential penetration of geothermal energy relative to the other technologies.

- Two modifications have been made in the electricity generation sector of NEMS since *AEO99* that tend to reduce the economic retirements of existing power plants. First, expectations of electricity demand growth, which are used internally to determine the requirements for new generation capacity, tended to be too high. This resulted in higher reserve margins and capacity additions. The methodology has been revised so that the initial electricity demand expectations used for capacity expansion are more in line with resulting forecasted demands. Also, projected capital costs for new capacity in *AEO2001* are generally higher for fossil-fired units than in *AEO99*, particularly for natural-gas-fired plants, which are 30 to 50 percent more costly, reducing retirements because the cost of replacing existing plants has increased.

In order to represent the *CEF* programs within NEMS for this study, each policy and its implementation in *CEF* were examined. Where possible, policies are explicitly represented, such as tax credits and efficiency standards. Many policies in *CEF*, including research and development and voluntary programs, were analyzed separately by the *CEF* analysts, and the results were introduced into *CEF*-NEMS through changes in parameters and assumptions, such as technology costs and performance and hurdle rates. For this study, EIA analysts generally implemented the same changes, on a percentage basis, into the current version of NEMS. Where *CEF* policies are date-dependent, due to the passage of time, as noted above, they are adjusted for the year of implementation, which has an impact on the level of penetration. The specific implementation of the *CEF* policies is discussed in Chapter 3.

As requested by Senators Jeffords and Lieberman, the overall goal of the EIA implementation of *CEF* policies is to emulate the analysis originally performed by the *CEF* analysts, while adjusting for the model enhancements and updated assumptions in *AEO2001*. In addition, the analysis is adjusted for any changes in energy programs and policies that have occurred since the *CEF* analysis. Therefore, although actual demand projections and demand reductions in the EIA analysis due to *CEF* policies may not match those in the published *CEF* analysis, the EIA analysis captures the essence of an updated *CEF* analysis.

[17] In *CEF*, policies for encouraging industrial cogeneration, or combined heat and power, were analyzed outside of *CEF*-NEMS and were not included in the integrated analysis or results.