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Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants

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Preface

Over the next decade, power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in the Clean Air Act Amendments of 1999. They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. Several proposed bills in Congress have targeted reductions of these four emissions. At present, neither the future reduction requirement nor the complete timetable is known for any of these airborne emissions, and compliance planning is difficult.

Recently, plans have been proposed that would require simultaneous reductions of multiple emissions. This analysis responds to a request from Senators Bob Smith, George Voinovich, and Sam Brownback to examine the costs of specific multi-emission reduction strategies (see Appendix A for the requesting letter). In their request Senators Smith, Voinovich, and Brownback asked the Energy Information Administration (EIA) to analyze the impacts of three scenarios with alternative power sector emission caps on NO_x, SO_2 and Hg. They also requested an analysis of the potential impacts of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008.

The projections and quantitative analysis for this report were prepared using the National Energy Modeling System (NEMS), an energy-economy model of U.S. energy markets designed, developed, and maintained by EIA, which is used each year to provide projections for EIA's *Annual Energy Outlook* and for other analyses and service reports. Using econometric, heuristic, and linear programming techniques, NEMS consists of 13 modules that represent the demand (residential, commercial, industrial, and transportation sectors), supply (coal, renewables, oil, and natural gas supply and transmission and distribution), and conversion (refinery and electricity sectors) of energy, together with a macroeconomic module that links energy prices to economic activity, with a representation of international oil markets.

The report is organized as follows. Chapter 1 provides a brief introduction together with a description of the analysis cases and methodology. Chapter 2 provides electricity and fuel market results. Detailed results are provided in the appendixes.

Using its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review this analysis and provide comment. All comments from the reviewers either have been incorporated or were thoroughly considered for incorporation. As is always the case when peer reviews are undertaken, not all the reviewers may be in agreement with all the methodology, inputs, and conclusions of the final report. The contents of the report are solely the responsibility of EIA. The assistance of the following reviewers is gratefully acknowledged:

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The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the U.S. Department of Energy or any other organization.

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

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Executive Summary

This analysis responds to a request from Senators Smith, Voinovich, and Brownback to examine the costs of specific multi-emission reduction strategies in the electricity generation sector (see Appendix A for the requesting letter). In their request, Senators Smith, Voinovich, and Brownback asked the Energy Information Administration (EIA) to analyze the impacts of three scenarios with alternative power sector emission caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2) and mercury (Hg). They also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in carbon dioxide (CO_2) emissions that occur beyond the level expected in 2008.

Specifically, EIA was asked to analyze the following three scenarios for reducing power sector emissions with and without holding CO_2 emissions to 2008 reference case levels:

- **Scenario 1:** Reduce NO_x emissions by 75 percent below 1997 levels, SO_2 emissions by 75 percent below full implementation of Title IV of the Clean Air Act Amendments of 1990 (CAAA90), and Hg emissions by 75 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.
- **Scenario 2:** Reduce NO_x emissions by 65 percent below 1997 levels, SO_2 emissions by 65 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 65 percent below 1999 levels by 2012, with half the reductions occurring by 2007.
- **Scenario 3:** Reduce NO_x emissions by 50 percent below 1997 levels, SO_2 emissions by 50 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 50 percent below 1999 levels, with half the reductions occurring by 2007.

The emissions reduction programs are assumed to cover all power generators other than industrial cogenerators and are patterned after the SO_2 allowance trading program created in the CAAA90. For Hg the Senators specified that half the reductions required in each scenario are to come from site-specific reductions. The specific emission caps imposed in each case are given in Table ES1.

The key results of controlling NO_x, SO_2, and Hg to the required levels include:

- Adding emissions control equipment to reduce NO_x, SO_2, and Hg is projected to be the dominant compliance option (Table ES2). The values in Table ES2 indicate that emissions control equipment is expected to be added to many of the existing U.S. coal-fired electric power plants, which currently total just over 300 gigawatts of capacity. The percentage of existing coal-fired capacity expected to have SO_2 scrubbers is larger than suggested by the values shown in Table ES2, because 90 gigawatts of that capacity already is equipped with scrubbers.
- Decreased use of coal and increased use of natural gas in the electricity sector is projected to result when emission reduction efforts of these levels are required. By 2020, coal-fired electricity generation is projected to be between 4 percent and 10 percent below the reference case level, and natural-gas-fired generation is projected to be between 4 percent and 10 percent above the reference case level (Table ES3).
- The potential for emission "leakage" outside the electricity generation sector is slight,[1] because coal plays such a small role in the residential, commercial, and industrial sectors and because the higher natural gas prices that result from increased use of natural gas in the generation sector lead to lower overall fuel consumption and lower emissions in the non-electricity sectors.

Table ES1. Emission Reduction Targets in the Analysis Cases

Emissions	Base Level for Reductions[a]	Reduction Targets: 50-Percent Reduction Case	65-Percent Reduction Case	75-Percent Reduction Case
NO_x (Thousand Tons)	6,191	3,096	2,167	1,548
SO_2 (Thousand Tons)	8,950	4,475	3,133	2,238
Hg (Tons)	43	22	15	11

[a]The base level for NO_x is 1997 emissions. For SO_2 it is the final target in the Clean Air Act Amendments of 1990. For Hg it is estimated 1999 emissions.

Source: Analysis request letter (see Appendix A).

[1]Emission leakage occurs when control programs in a sector that is covered lead to actions that increase emissions in sectors not covered by the programs.

- Emission allowance costs and electricity prices are projected to increase as the caps on NO_x, SO_2, and Hg are tightened across the cases. The price of electricity is projected to be between 1 percent and 6 percent higher in 2020 than in the reference case. The Nation's total electricity bill (in 1999 dollars) is projected to be between $3 billion and $13 billion (1 to 5 percent) higher in 2020 than projected in the reference case.

- Over the 2001 to 2020 forecast period, power supplier resource costs (in 1999 dollars) are projected to be between $28 billion and $89 billion higher than in the reference case.

- If power suppliers were required to purchase offsets for CO_2 emissions above the level projected to be emitted in 2008 in the reference case, they would need to purchase between 65 million and 89 million metric tons of offsets in 2020. There is considerable uncertainty about the potenial price of carbon offsets in world markets, and EIA has not performed any analysis in this area; however, using information from the Pacific Northwest Laboratory's Second Generation Model (SGM) and assuming that the United States would not participate in the Kyoto Protocol, it appears that full worldwide trading of energy-related carbon offsets would lead to a price of about $10 per ton. At that price, the cost of purchasing offsets in the three cases would range between $654 million and $888 million in 2020, or roughly 0.3 to 0.4 percent of the industry's projected revenue in 2020. If trading programs also include offsets from reductions in emissions of other greenhouse gases (such as methane) or investments in "carbon sinks" (such as reforestation programs)—which are not analyzed in this report—the costs could be lower.

- As in any 20-year projection, these results include numerous uncertainties. Key uncertainties include the following:
  - **Future natural gas prices.** Higher natural gas prices than those projected in this report would increase the costs of reducing power sector emissions.
  - **Cost and performance of new emissions control equipment.** Because few full-scale tests have been conducted, there is significant uncertainty about the cost and performance of Hg control equipment. In addition, the impact of equipment designed to remove NO_x and SO_2 on Hg emissions is also uncertain at this time.

Table ES2. Projected Additions of Emissions Control Equipment, 1999-2020
(Gigawatts)

Analysis Case	Cumulative Capacity Adding Controls				
	SO_2 Scrubber	Selective Catalytic Reduction (SCR)	Selective Noncatalytic Reduction (SNCR)	Hg Fabric Filter	Hg Spray Cooler
Reference	17.5	91.1	46.0	0.0	0.0
50-Percent Reduction	90.0	98.0	14.6	45.5	1.6
65-Percent Reduction	127.3	156.3	55.5	60.5	3.8
75-Percent Reduction	151.5	218.1	43.8	66.9	29.3

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits. SCRs and SNCRs are NO_x removal technologies.
Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

Table ES3. Key Projections in the Analysis Cases, 2020

Analysis Case	SO_2 Allowance Price (1999 Dollars per Ton)	NO_x Allowance Price: Annual (1999 Dollars per Ton)	NO_x Allowance Price: Seasonal (1999 Dollars per Ton)	Hg Allowance Price (1999 Dollars per Pound)	Electricity Price (1999 Cents per Kilowatthour)	Electricity Sales (Billion Kilowatthours)	Electricity Industry Revenues (Billion 1999 Dollars)
Reference	200	0	5,087	0	6.13	4,763	292
50-Percent Reduction	719	1,108	0	21,119	6.22	4,749	295
65-Percent Reduction	1,390	1,457	0	41,190	6.35	4,736	301
75-Percent Reduction	1,737	2,825	0	85,225	6.48	4,716	305

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits.
Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

– **The changing structure of U.S. electricity markets.** This study assumes that wholesale power markets in the U.S. will behave competitively. If they do not, compliance costs could be higher.

– **The policy instrument used to reduce power plant emissions.** This study assumes that an efficient cap and trade system will be set up to reduce power plant emissions. Numerous other policy instruments—such as taxes, technical standards, or a generation performance standard with cap and trade—are available. If an alternative instrument were used, the compliance costs and price impacts would be different from those projected in this analysis.

1. Background and Methodology

Introduction

Over the next decade, U.S. electric power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in the Clean Air Act Amendments of 1990 (CAAA90). They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. At present neither the future reduction requirement nor the timetable is known for any of these airborne emissions; thus, compliance planning is difficult.

Currently, different environmental issues are being addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, the 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 these 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 that lead to 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 emitted directly from electric power plants and are also associated with power plant emissions of NO_x and SO_2. Thus, 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; proposed regulations are to be finalized by 2004. Further, if the United States decides to reduce its emissions of greenhouse gases, energy-related CO_2 emissions may have to be reduced as part of that program.

Analysis Request

In both the previous and current Congresses, legislation has been proposed that would require simultaneous reductions of multiple emissions.[1] This analysis responds to a request from Senators Smith, Voinovich, and Brownback to examine the costs of specific multi-emission reduction strategies (see Appendix A for the requesting letter). In their request, Senators Smith, Voinovich, and Brownback asked the Energy Information Administration (EIA) to analyze the impacts of three scenarios with alternative power sector emission caps on NO_x, SO_2 and Hg. They also asked for an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008.

Specifically, EIA was asked to analyze the following three scenarios for reducing power sector emissions:

- **Scenario 1:** Reduce NO_x emissions by 75 percent below 1997 levels, SO_2 emissions by 75 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 75 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.

- **Scenario 2:** Reduce NO_x emissions by 65 percent below 1997 levels, SO_2 emissions 65 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 65 percent below 1999 levels by 2012, with half the reductions occurring by 2007.

- **Scenario 3:** Reduce NO_x emissions by 50 percent below 1997 levels, SO_2 emissions by 50 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 50 percent below 1999 levels by 2012, with half the reductions occurring by 2007.

[1] For more discussion of proposed bills, see 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/.

The emission reduction programs are assumed to cover all electricity generators other than industrial cogenerators,[2] and to operate as cap and trade programs patterned after the SO_2 control program created in the CAAA90. It was requested that the analysis should assume that the programs would begin in 2002, achieving half the required reductions by 2007 and full compliance by 2012. At the request of the Senators the existing summer season NO_x cap and trade program is assumed to be replaced by the annual programs established in each of the cases.

For Hg, half of the required reductions were to come from actual reductions at each unit; the rest could be achieved through allowance trading among units. In all cases, power suppliers would be able to bank emissions for future use. In other words, power suppliers could choose to reduce their emissions below the number of allowances they have in some years and hold (bank) them for use in other years. Typically a power supplier would be expected to do this in the early phase of the emission reduction programs, when relatively inexpensive compliance options are available, so that they could minimize the amount of reduction they might have to make or the number of allowances they might have to buy in the later phases, when compliance might be more expensive.

This analysis examines the steps that power suppliers might take to meet the specified caps on NO_x, SO_2, and Hg emissions with and without CO_2 emissions capped at the 2008 reference case level. The potential benefits of reduced emissions—such as might be associated with reduced health care costs—are not addressed, because EIA does not have expertise in this area.[3] The specific design of the cases—timing, emission cap levels, policy instruments used—is important and should be kept in mind when the results are reviewed.

This study is not intended to be an analysis of any of the specific congressional bills that have been proposed in this area, 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 emission caps studied in this analysis, and several would use different policy instruments to meet the emission targets. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be required as a result of ongoing environmental programs whose requirements currently are not fully specified.

Representation in the National Energy Modeling System

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

Domestic energy markets are modeled by representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most sectors, NEMS includes explicit representation of energy technologies and their characteristics (Table 1). In each sector of NEMS, economic agents—for example, representative households in the residential demand sector and producers in the industrial sector—are assumed to evaluate the cost and performance of various energy-consuming technologies when making their investment and utilization decisions. The costs of making capital and operating changes to comply with laws and regulations governing power plant and other emissions are included in the decisionmaking process.

The rich detail in NEMS makes it useful for evaluating various energy policy options. Policies aimed at a particular sector of the energy market often have collateral effects on other areas that can be important, and the detail of NEMS makes the analysis of such impacts possible. For example, a policy that leads to higher prices for a particular fuel would be expected to cause residential, commercial, industrial, and transportation customers to

[2]Industrial generators currently account for approximately 8 percent of total generation, with approximately two-thirds being generated from natural gas.

[3]For benefit studies, see bibliography in 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/.

reduce their consumption of that fuel by shifting to other fuels and/or investing in more efficient energy-using equipment. NEMS explicitly represents these choices by consumers.[4]

NEMS represents numerous options for reducing power sector emissions of NO_x, SO_2, and Hg. Technological options include installing combustion controls, selective noncatalytic reduction equipment (SNCR), or selective catalytic reduction equipment (SCR) to reduce NO_x; flue gas desulfurization equipment to reduce SO_2; and activated carbon injection equipment with or without a supplemental fabric filter or spray cooler to reduce Hg. With respect to Hg and, to a lesser extent, NO_x there is some uncertainty about the cost and performance of these technologies (see box on page 4). NEMS can also choose

Table 1. National Energy Modeling System Energy Activities

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

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

[4]For more information on the representation of emission caps in NEMS, see Chapter 2 in 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/.

to switch fuels or retire plants and replace them with new plants using different technologies or fuels. Finally, NEMS allows consumers to choose to reduce their electricity consumption if electricity prices rise when emission caps are imposed.

Reference Case

The reference case for this analysis is based on the reference case for EIA's *Annual Energy Outlook 2001* (*AEO2001*). As a result, it incorporates the laws and regulations that were in place as of the end of July 2000. It includes the CAAA90 SO_2 emission cap and NO_x boiler standards. It also includes the 19-State summer season NO_x emission cap program—referred to as the "State Implementation Plan (SIP) Call."[5] The settlement agreement between the Tampa Electric Company and the U.S. Department of Justice (acting for the EPA) requiring the addition of emissions control equipment at the Big Bend power plant and the conversion of the F.J. Gannon plant

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.

[5] For more discussion of the treatment of environmental rules and regulations in the reference case, see page 9 of 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/.

to natural gas was also incorporated in the *AEO2001* reference case. Rules and regulations that have not been fully promulgated are not included in the reference case (see box below).

Because of the recent agreements between the EPA and Cinergy and Virginia Power with respect to the New Source Review (NSR) compliance action, the *AEO2001* reference case has been modified for this study to incorporate the emissions control equipment that those companies have announced they will add. However, these actions could change as a result of the remaining NSR cases. The historical data used for this analysis were also updated to reflect more recent information on natural gas prices, electricity sales, and generating capability additions in 2000 that were not available when the *AEO2001* reference case was prepared. In addition, natural gas prices and electricity demands have been recalibrated to EIA's July 2001 *Short-Term Energy Outlook* (*STEO*). This recalibration resulted in higher gas prices and electricity demand than those used in the *AEO2001*.

Analysis Cases

As requested by the Senators, the emission reduction programs are assumed to be patterned after the SO_2 emissions trading program created in the CAAA90. In other words, emissions allowances totaling to the specified limit for each emission are assumed to be allocated at no cost to power suppliers. Power suppliers are free to reduce their emissions to the level of allowances they hold or to purchase additional allowances from others who take action to reduce their emissions below the number of allowances they have. Power suppliers are assumed to behave competitively, incorporating the

Representation of New Environmental Rules and Regulations

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

The reference case for this analysis excludes several potential environmental actions, such as new regulations affecting regional haze, for which States are developing implementation plans; 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.

(continued on page 6)

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

costs[6] of holding allowances in the operating costs of plants that produce the targeted emissions. Assuming that efficient competitive allowance markets develop, the market price of allowances that evolves should provide both power producers and consumers with the information needed to minimize the costs of reducing the targeted emissions.

It is important to note that there are numerous policy instruments available for reducing emissions. They include 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 trade program is expected to lead to the lowest resource costs of compliance.[7] In competitive markets, electricity prices will reflect the change in variable operating costs of plants setting market prices brought about by emission reduction efforts. On the other hand, in cost-of-service markets, all generation costs—including the total costs of reducing emissions—will be reflected in the prices that consumers pay for electricity.

Table 2 and Figures 1, 2, and 3 show the emission targets in each of the three cases prepared—50-Percent, 65-Percent and 75-Percent Reduction cases. In each case it is assumed that half the required reduction must occur by 2007, and that full compliance is required by 2012. Thus, the emission limits in 2007 are set to the mid-point between the base level and the emission target level shown for each case in Table 2. In 2012 and beyond, the emission caps are set to the levels shown in Table 2.

At the request of the Senators, an additional requirement is imposed for Hg: one-half of the required reductions in each case must come from reductions at each facility, and the other half can be accomplished through trading with other facilities that have allowances to sell. To represent this requirement an estimate was made of the minimum percentage Hg removal (from the amount of Hg in the coal used) required from all units to achieve half the overall required reduction by 2007. For example, in the 65-Percent Reduction case, 28 tons of reduction

Representation of New Environmental Rules and Regulations (Continued)

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.

Readers should keep in mind that some of the projected actions and costs incurred to comply with the emissions caps analyzed in this report may also result from the other pending rules and regulations discussed above when they are finalized. Projections in the reference case in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as now enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

[6]Even when allowances are allocated at zero cost, there are opportunity costs associated with them. By using its own allowances, a company forgoes the revenue that could be made by selling them.

[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 Emissions Trading" (Washington, DC: Resources for the Future, Discussion Paper 01-30, August 2001); and C. Fischer, "Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards" (Washington, DC: Resources for the Future, Discussion Paper 01-22, July 2001). For a discussion of the impacts of a generation performance standard approach see, J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emissions Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf.

(43 - 15) is required. It was estimated that if all units were required to add equipment that allowed them to achieve a minimum 55 percent removal rate (units that already removed more than 55 percent were not required to make any additional investment), approximately half the 28 tons of total reductions required would be achieved. The same procedures were used in the 50- and 75-Percent Reduction cases, but the minimum removal rates were 50 percent and 60 percent, respectively.

Power sector banking decisions were simulated by setting the emissions caps slightly below those called for in the early years of the programs and slightly higher in the later years. In all cases, it is assumed that emissions will reach the final target caps by 2020.[8]

In addition, for each of the three analysis cases an estimate is provided of the cost of purchasing carbon offsets for increases in CO_2 emissions beyond the 2008 level projected in the reference case. NEMS represents only U.S. energy markets and can only provide cost estimates for reducing emissions in the U.S. energy sector. Lower cost carbon reduction opportunities that might be available in other countries and / or outside the energy sector (inside and outside the United States) are not represented in NEMS.

To estimate the potential price that U.S. power suppliers might be willing to pay for carbon offsets, each of the three analysis cases was rerun with CO_2 emissions capped at the reference case 2008 level. The resulting

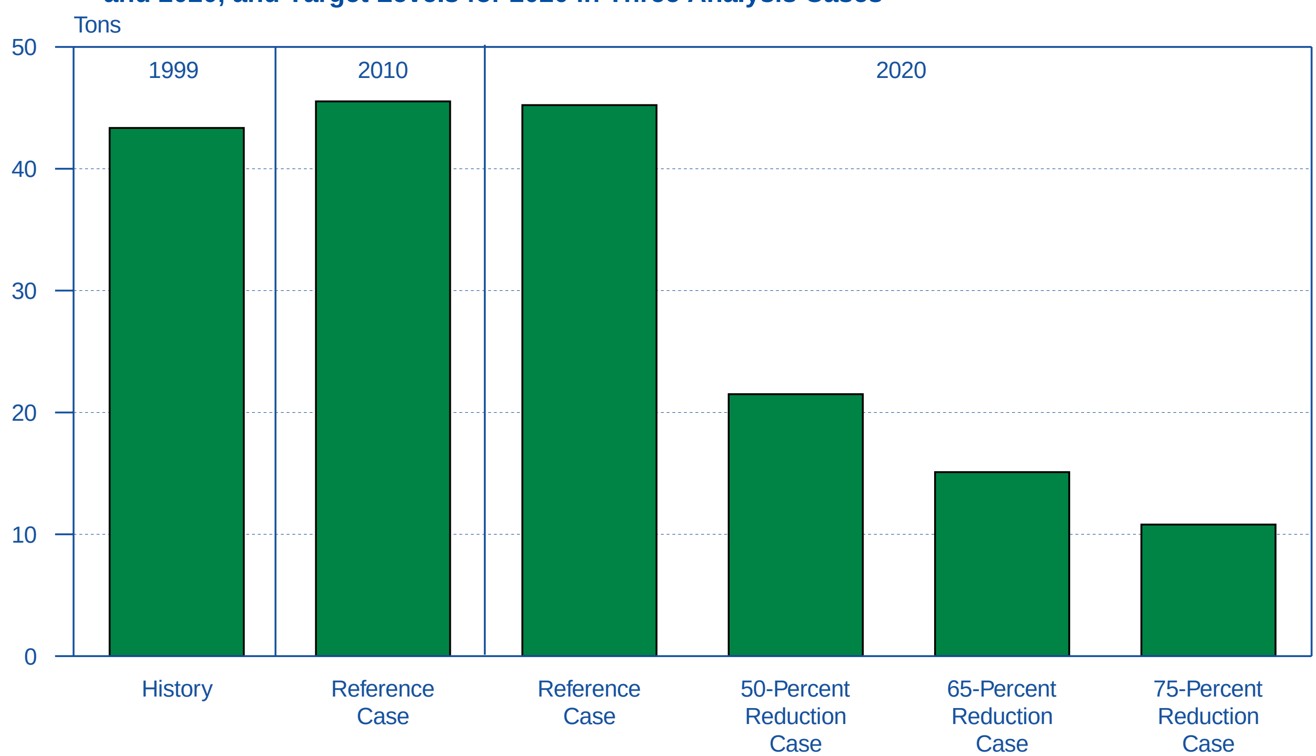
Table 2. Emission Reduction Targets in the Analysis Cases

Emissions	Base Level for Reductions[a]	Reduction Targets: 50-Percent Reduction Case	Reduction Targets: 65-Percent Reduction Case	Reduction Targets: 75-Percent Reduction Case
NO_x (Thousand Tons)	6,191	3,096	2,167	1,548
SO_2 (Thousand Tons)	8,950	4,475	3,133	2,238
Hg (Tons).	43	22	15	11

[a]The base level for NO_x is 1997 emissions. For SO_2 it is the final target in the Clean Air Act Amendments of 1990. For Hg it is estimated 1999 emissions.

Source: Analysis request letter (see Appendix A).

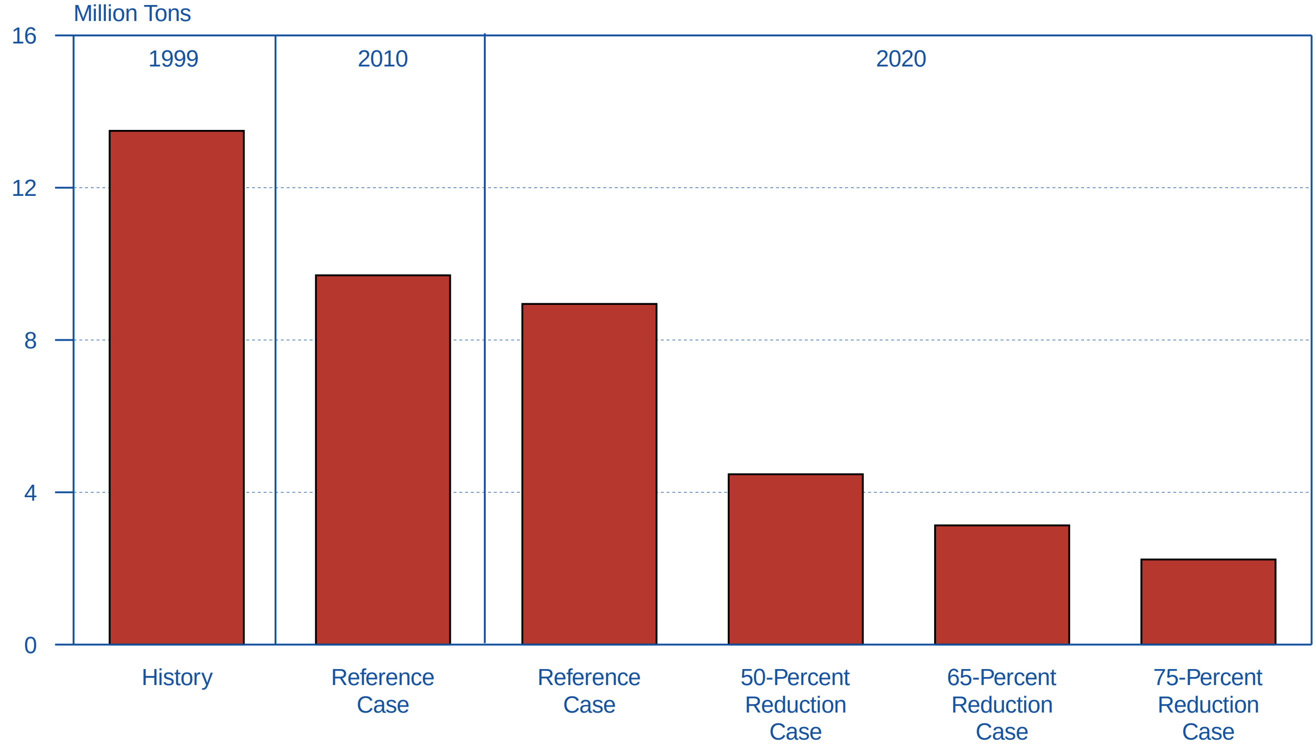
Figure 1. Mercury Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

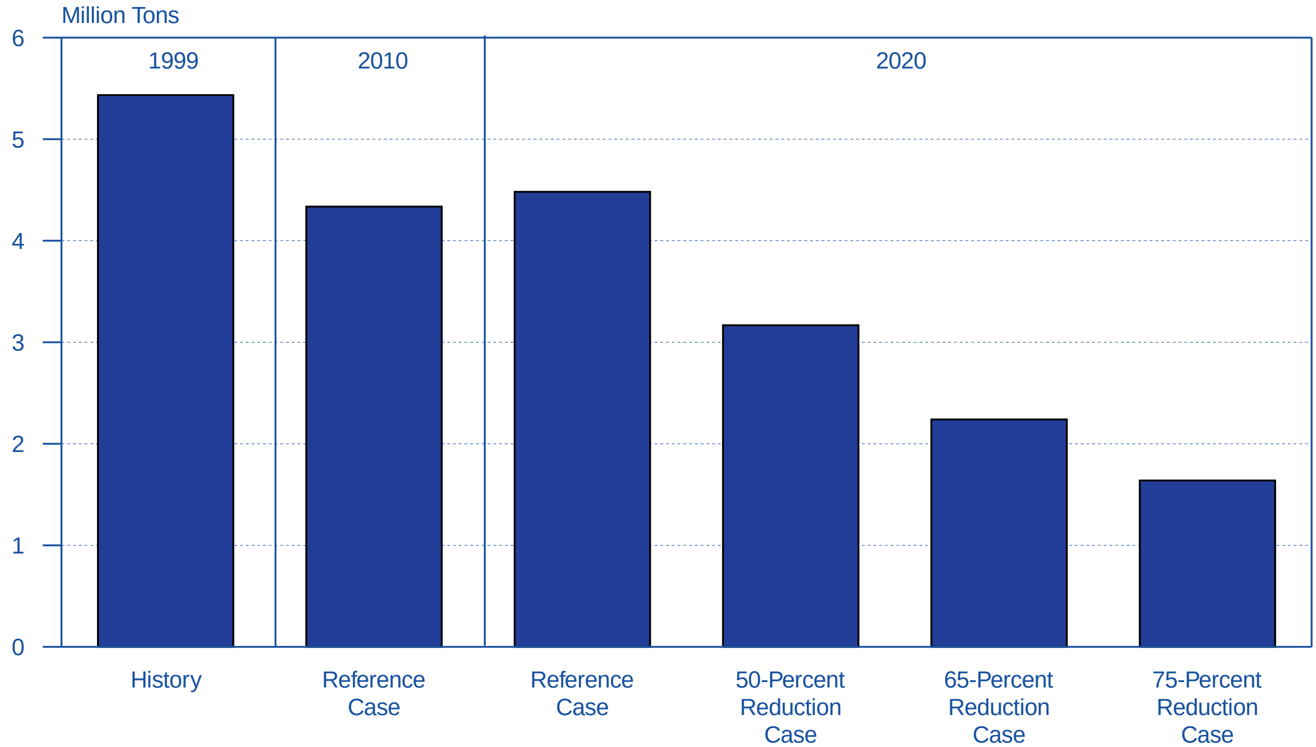
[8]Banking decisions were estimated exogenously.

Figure 2. Sulfur Dioxide Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

Figure 3. Nitrogen Oxides Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

CO_2 allowance price, which represents the projected maximum price U.S. power suppliers would be willing to pay, was then compared with an estimate of the international price for carbon offsets from world energy markets. This estimate was developed using carbon reduction (abatement) curves from the Pacific Northwest Laboratory Second Generation Model (SGM), matched against the quantity of offsets projected to be needed in each of the analysis cases,[9] to provide a rough estimate of the costs power suppliers would incur to purchase the offsets they would require in each case. No explicit reductions in U.S. power sector CO_2 emissions were modeled. It is likely that the U.S. power sector would have some relatively inexpensive options available.

[9]Output received from Pacific Northwest Laboratory August 30, 2001. Because the Second Generation Model is an energy sector model, offsets that might be available from non-energy sectors (such as agricultural changes or reforestation activities) are not represented.

2. Impacts on Electricity Generation and Key Fuel Markets

Reference Case Trends

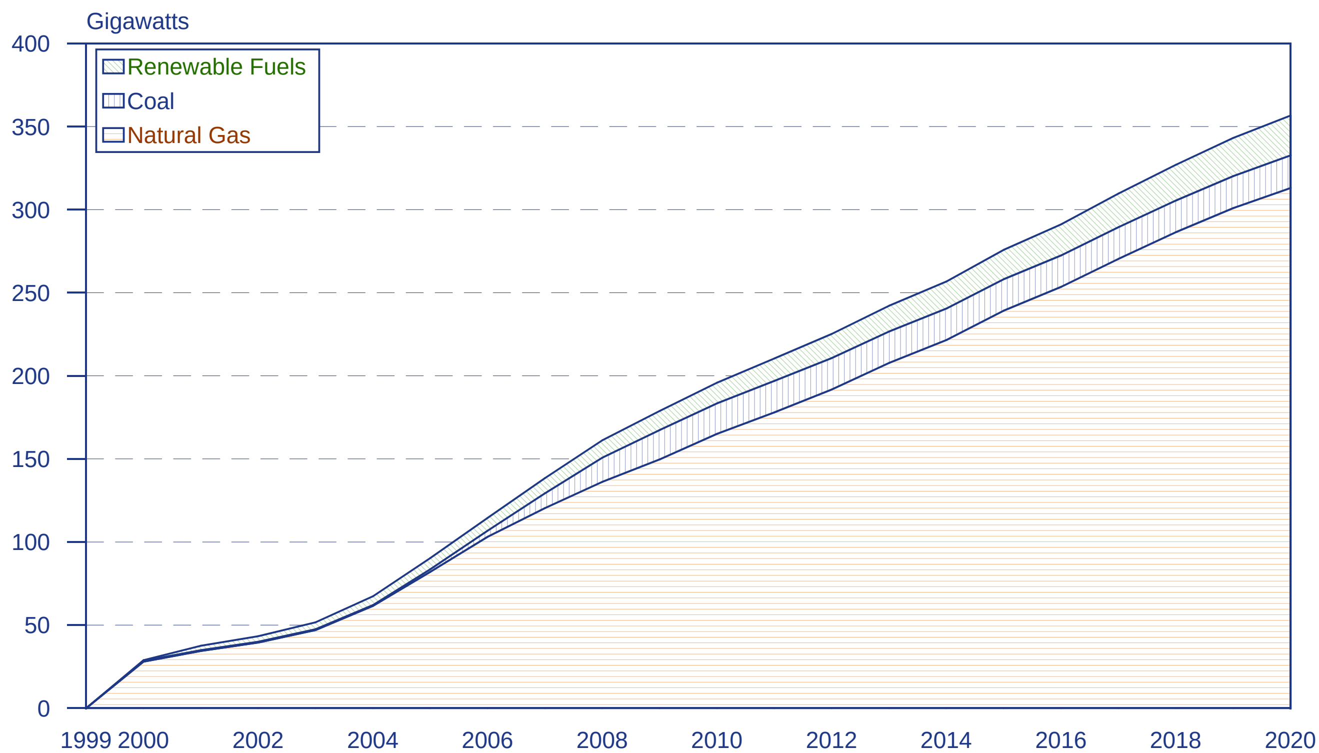
Over the next 20 years the demand for electricity is projected to grow by 1.8 percent per year, as compared with the 1990s, during which electricity consumption grew by 2.3 percent annually. Growth in electricity use is expected to slow as new, more efficient appliances enter the market and industrial production continues to shift away from energy-intensive industries. With 3.0-percent annual growth projected for the economy as a whole, the overall electric intensity of the U.S. economy—measured as the ratio of electricity use to gross domestic product—is projected to decline by 22 percent between 2000 and 2020.

To meet the growth in demand for electricity, 357 gigawatts of new generating capacity is projected to be needed (Figure 4). The vast majority of new plants are expected to be natural gas fired, with lesser amounts of new coal-fired and renewable capacity. New natural gas-fired combustion turbines and combined cycle plants are the most economical options for most uses. They generally have lower capital costs than other options and they are becoming increasingly efficient.

With the addition of many new natural-gas-fired plants, the share of electricity generated from natural gas is projected to grow from 16 percent in 1999 to 34 percent in 2020 (Figure 5). Generation from coal-fired plants is also projected to grow as a small number of new plants are added and as existing plants are used more intensively, but the *share* of generation coming from coal is projected to decline slightly. On the other hand, generation from oil and from nuclear power is expected to decline as some older plants are retired in the later years of the forecast. Generation from renewable plants is projected to increase, but not enough to maintain its current share.

Although fossil fuel use is expected to grow over the next 20 years, SO_2 and NO_x emissions are not projected to be higher in 2020 than they are today (Figures 6 and 7). As a result of the emission reduction programs established in the Clean Air Act Amendments of 1990 (CAAA90) SO_2 and NO_x emissions are expected to be

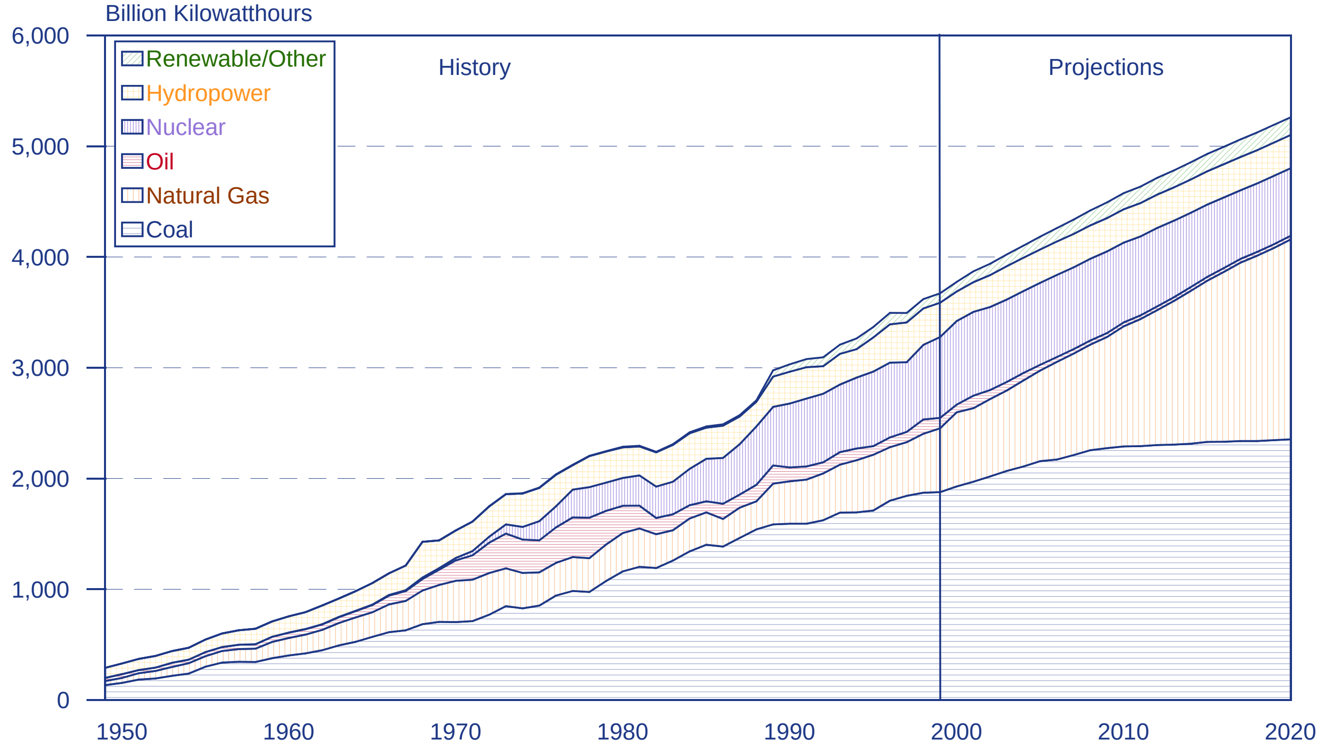
Figure 4. Projected Cumulative Additions to U.S. Electricity Generating Capacity, 1999-2020



Source: National Energy Modeling System, run SCENABS.D080301A.

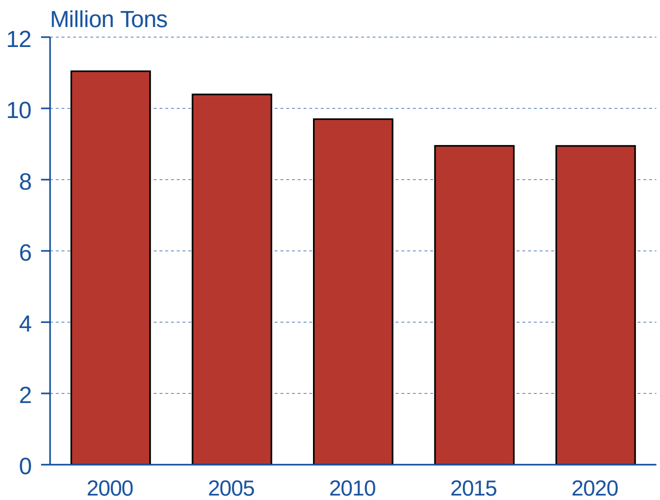
lower in 2020 than they were in 1999. For example, the CAAA90 cap on power sector SO_2 emissions is set at 8.95 million tons for the years 2010 and beyond, and that cap is expected to become binding in the later years of the reference case projections as power companies exhaust their supplies of banked allowances.[10] For NO_x, 19 States in the Midwest and Eastern regions and the District of Columbia are projected to see significant reductions in emissions beginning in 2004, when a summertime emissions cap takes effect. The summer

Figure 5. Electricity Generation by Fuel, 1949-1999, and Projections for the Reference Case, 2000-2020



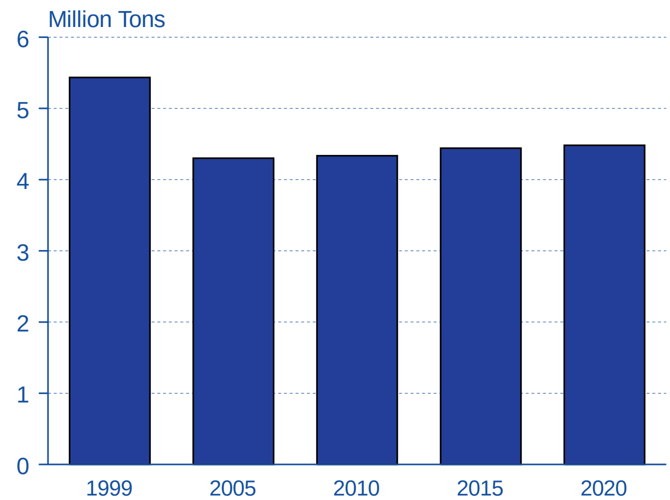
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run SCENABS.D080301A.

Figure 6. Projected Electricity Generation Sector Sulfur Dioxide Emissions in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

Figure 7. Projected Electricity Generation Sector Nitrogen Oxides Emissions in the Reference Case, 2000-2020



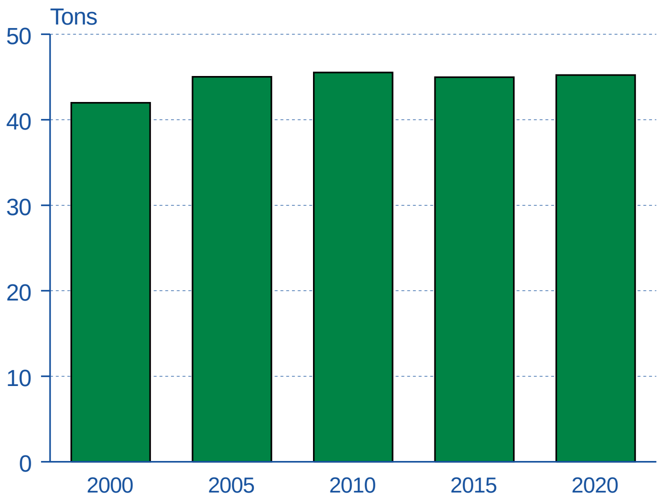
Source: National Energy Modeling System, run SCENABS. D080301A.

[10] Power companies created "banked allowances" by overcomplying during the first phase of the CAAA90 SO_2 program, from 1995 to 1999. They can use those allowances in later years.

season cap begins in 2004 and is maintained throughout the rest of the projections. Total U.S. NO_x emissions are projected to increase slightly after 2004, but not enough to offset the earlier reduction.

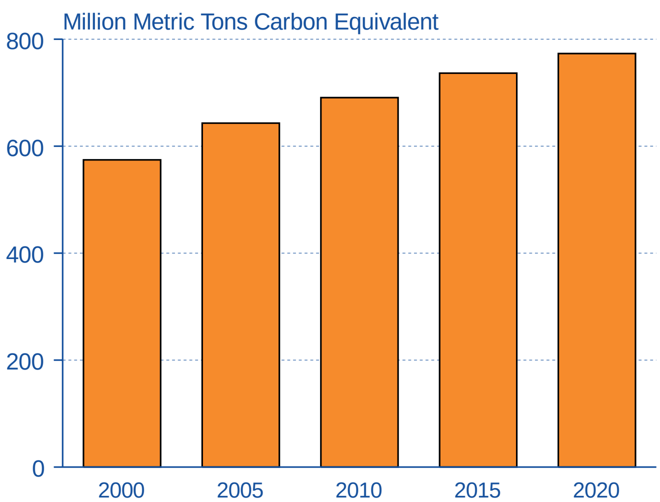
Hg emissions from electric power plants are projected to remain fairly steady between 2000 and 2020—hovering around 45 tons from 2005—despite the expected increase in coal use (Figure 8). Some existing coal plants are projected to add scrubbers to reduce SO_2 emissions and selective catalytic reduction (SCR) equipment to reduce NO_x emissions, and all new coal plants are projected to have scrubbers, SCRs, and fabric filters. While these technologies are designed primarily to reduce SO_2, NO_x, and particulate emissions, they also help to reduce Hg emissions. The addition of this equipment is expected to nearly offset the increase in Hg emissions that would be expected with increasing coal use.

Figure 8. Projected Electricity Generation Sector Mercury Emissions in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

Figure 9. Projected Electricity Generation Sector Carbon Dioxide Emissions in the Reference Case, 2000-2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, run SCENABS. D080301A.

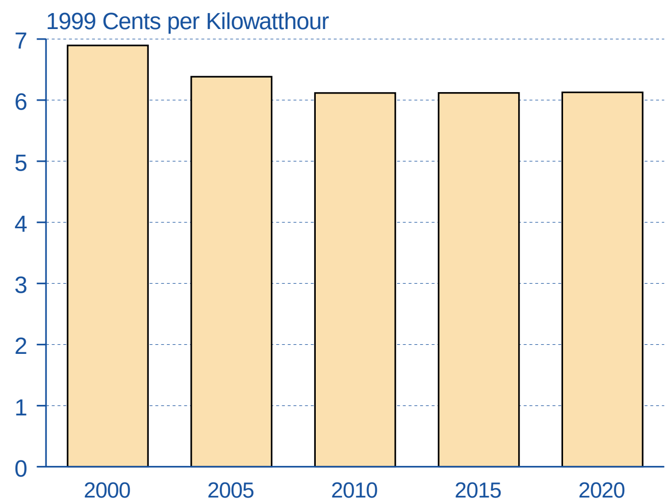
Unlike NO_x, SO_2, and Hg emissions, CO_2 emissions (expressed in metric tons carbon equivalent throughout this report) are projected to rise steadily over the next 20 years as the power sector becomes increasingly dependent on fossil fuels (Figure 9). Between 1999 and 2020, the share of electricity generation from fossil fuels is expected to increase from 69 percent to 80 percent, and CO_2 emissions from electric power plants are expected to increase by 217 million metric tons—39 percent—over the next 20 years. The actions projected to be taken to reduce SO_2 and NO_x emissions in the reference case in response to the CAAA90 are not expected to reduce power sector CO_2 emissions, because they will not lead to significant fuel switching.

Despite the growing demand for electricity, prices are expected to decline by 9 percent in real terms over the next 20 years (Figure 10). The phase-in of competition in many regions of the country is one factor in the expected decline, in addition to falling coal prices and the declining cost and increasing performance of new natural gas technologies.

Reducing Electricity Sector NO_x, SO_2, and Hg Emissions

A number of options are available to reduce power sector emissions of NO_x, SO_2, and Hg. They include emission control options such as adding combustion controls and SCR and selective noncatalytic reduction (SNCR)

Figure 10. Projected Electricity Prices in the Reference Case, 2000-2020



Source: National Energy Modeling System, run SCENABS. D080301A.

equipment designed primarily to reduce NO_x emissions, flue gas desulfurization equipment (scrubbers) to reduce SO_2, and activated carbon injection (ACI) equipment to reduce Hg.[11] Other options for reducing NO_x, SO_2, and Hg emissions include fuel switching (either by changing fuels at existing plants or by retiring plants and replacing them with plants that use different fuels) and reducing consumer demand.

In the cases examined in this report all three of the options above are expected to play a role; but by a large margin, the key strategy projected to be used is the installation of emissions control equipment to reduce the three emissions. As shown in Table 3, the amount of equipment projected to be added increases as the emission caps on the three pollutants are tightened. For example, scrubbers are projected to be added to 90 gigawatts of capacity by 2020 in the 50-Percent Reduction case and to 151 gigawatts in the 75-Percent Reduction case. The values in Table 3 indicate that emissions control equipment is expected to be added to many of the existing U.S. coal-fired electric power plants, which currently total just over 300 gigawatts of capacity. The percentage of existing coal-fired capacity expected to have SO_2 scrubbers is larger than suggested by the values shown in Table 3, because 90 gigawatts of that capacity already is equipped with scrubbers.

The projections are similar for NO_x emission controls: SCRs are expected to be added to 98 gigawatts of capacity in the 50-Percent Reduction case and to 218 gigawatts in the 75-Percent Reduction case. The investment in SCR technology increases continuously across the cases as the required percentage reduction increases. The same is true for expected additions of SNCRs between the 50-Percent and 65-Percent Reduction cases; but when the required reduction is raised to 75 percent, power suppliers are projected to shift increasingly to SCR technology because it can achieve greater NO_x reduction.

Relative to the reference case, less capacity is expected to be retrofitted with NO_x control technology in the 50-Percent Reduction case, because the 19-State summer season NO_x cap and trade program that is scheduled to begin in 2004 in the reference case is replaced by the national cap and trade program in each of the analysis cases. In the 50-Percent Reduction case the annual NO_x cap, 3.1 million tons (roughly equivalent to an average annual emission rate of 0.25 pounds per million Btu of fossil fuel consumed in 2010 and 0.18 pounds per million Btu in 2020), can be met with less control equipment than is required to meet the seasonal cap in the reference case. The 19-State summer season NO_x emissions cap represented in the reference is based on a target average emission rate of 0.15 pounds per million Btu of fossil fuel consumed. The NO_x emission caps in the 65-Percent and 75-Percent Reduction cases—2.2 million tons and 1.5 million tons, respectively—lead to average annual NO_x emission rates below 0.15 pounds per million Btu by 2020.

In many other aspects—including fuel use, generation by fuel, and capacity additions by type—the results in the three analysis cases are similar to those in the reference case. As the emission caps are tightened across the cases there is a slight shift from coal-fired generation to

Table 3. Projected Additions of Emissions Control Equipment, 1999-2010 and 1999-2020
(Gigawatts)

Analysis Case	Cumulative Capacity Adding Controls				
	SO_2 Scrubber	Selective Catalytic Reduction (SCR)	Selective Noncatalytic Reduction (SNCR)	Hg Fabric Filter	Hg Spray Cooler
1999-2010					
Reference	8.9	90.9	28.5	0.0	0.0
50-Percent Reduction	47.8	46.6	2.7	45.5	0.0
65-Percent Reduction	42.9	93.8	15.2	60.5	0.3
75-Percent Reduction	61.7	141.7	10.3	57.7	11.9
1999-2020					
Reference	17.5	91.1	46.0	0.0	0.0
50-Percent Reduction	90.0	98.0	14.6	45.5	1.6
65-Percent Reduction	127.3	156.3	55.5	60.5	3.8
75-Percent Reduction	151.5	218.1	43.8	66.9	29.3

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits. SCRs and SNCRs are NO_x removal technologies.

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

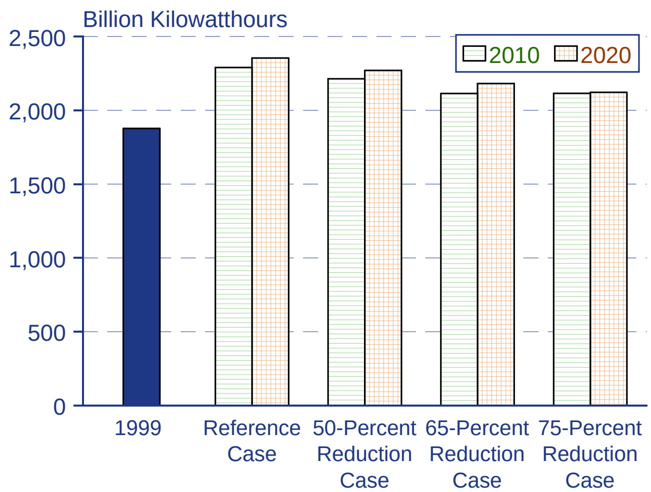
[11]Substantial uncertainty remains about the measurement and control of Hg emissions. For a discussion of this issue see pages 16 and 17 in Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

natural-gas-fired generation (Figures 11 and 12). For example, in the 75-Percent Reduction case, which is projected to have the largest shift, natural-gas-fired generation in 2020 is expected to be 10 percent above and coal-fired generation 10 percent below the reference case levels. The shifts in the two other cases are smaller.

As the emission caps are tightened across the cases, the projected allowance prices for NO_x, SO_2, and Hg are expected to increase, particularly as the caps are lowered to the limits in the 75-Percent Reduction case (Table 4). In this case, the emissions controls must be added to units for which the marginal costs per unit of reduction are higher. This is particularly true for allowance prices for NO_x and Hg. For example, the annual NO_x allowance price[12] in 2020 in the 65-Percent Reduction case is projected to be $1,457 per ton, but in the 75-Percent Reduction case it is 94 percent higher, at $2,825 per ton. Similarly, the Hg allowance price in 2020 in the 65-Percent Reduction case is projected to be $41,190 per pound, but in the 75-Percent Reduction case it is more than twice as high, at $85,225 per pound.[13] The requirements to reduce Hg have a significant impact on the SO_2 allowance price, especially as the Hg emission caps are initially phased in. The SO_2 allowance price in the 75-Percent Reduction case in 2010 is lower than in the 65-Percent Reduction case, because efforts to meet the tighter Hg emissions limit in the 75-Percent case also reduce SO_2 emissions.

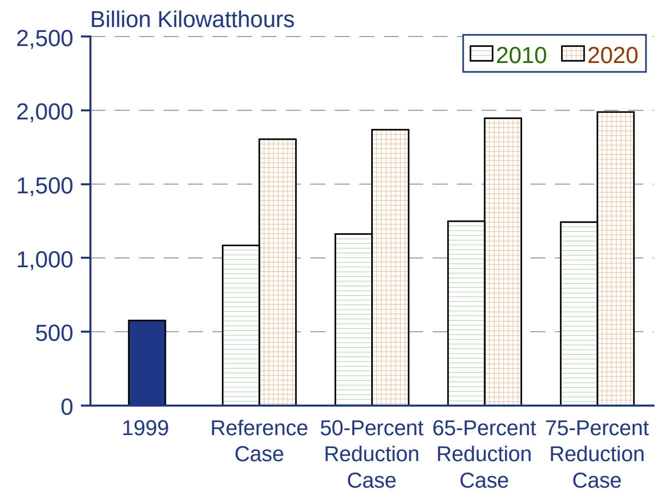
The increasing cost of allowances across the cases is driven by several factors. For example, for a particular plant, the plant size, sulfur content of the coal used, and plant capacity factor are important in determining the cost of reducing SO_2. Smaller plants are in general more costly (per unit of capacity) to retrofit with scrubbers than are larger plants. It is also more expensive on a per ton removal basis to control SO_2 at a plant using relatively low-sulfur coal. Similarly, it is more expensive on a per ton removal basis to add a scrubber to a plant that is not used intensively. For example, for a large plant with scrubber capital costs of $200 per kilowatt, using a 2-percent sulfur coal and operating at a 75-percent capacity factor, the cost of removing SO_2 is expected to be approximately $250 per ton. If the plant used a 1-percent sulfur coal the cost estimate would double, and if it operated at a 37.5-percent capacity factor the cost estimate would double again. For a smaller plant, with scrubber capital costs that could be $400 per kilowatt or more, the corresponding SO_2 removal costs would be even higher. As a result, when controls must be added to smaller plants that are already using relatively low-sulfur coals and operating less intensively, the per ton costs of removal can be quite high.[14]

Figure 11. Projected Electricity Generation from Coal-Fired Power Plants in Four Cases, 2010 and 2020



Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

Figure 12. Projected Electricity Generation from Natural-Gas-Fired Power Plants in Four Cases, 2010 and 2020



Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

[12]The reference case includes the summer season NOx cap that begins in 2004 for 19 midwestern and eastern states and the District of Columbia. The analysis cases include only the annual NO_x reduction programs requested.

[13]The Hg allowance price in 2010 is $0 in each of the three analysis cases, because it is assumed that each plant must achieve a specified reduction—set to achieve half the total required reduction—by 2007. Because these reductions are sufficient to meet the 2010 overall cap, the allowance price is $0.

[14]The examples given in this paragraph assume a 15-percent fixed charge factor, a 2.5-percent heat rate penalty, and a coal price of $1 per million Btu. They do not represent the costs for any particular plant but are meant to be illustrative.

Investments in emissions control technology, combined with higher expenditures for natural gas, are projected to lead to higher supplier resource costs in the three emission reduction cases (Table 5). Supplier resource costs include electricity producers' expenditures on fuel, nonfuel operations and maintenance costs, and investments in new plants and emissions control equipment. In the 75-Percent Reduction case, suppliers are projected to incur $89 billion (constant 1999 dollars) more in resource costs between 2001 and 2020 than in the reference case (Figure 13). On an average annual basis, the increases in resource costs in the three cases average $1.4 billion, $3.3 billion, and $4.4 billion, in the 50-Percent, 65-Percent, and 75-Percent Reduction cases, respectively.[15]

Changes in electricity prices are expected to parallel the changes in supplier resource costs in the three analysis cases (Figure 14). In percentage terms, electricity prices in 2010 are expected to range between 0 and 2 percent higher than in the reference case; and in 2020, as the emission caps tighten, they are expected to range between 2 and 6 percent higher. On an average annual basis, the projected increases in electricity revenues (prices times sales) relative to the reference case in 2020 are $4 billion, $9 billion, and $14 billion in the 50-Percent, 65-Percent, and 75-Percent Reduction cases, respectively.

Offsetting CO_2 Emissions Growth After 2008

Because of the slight shift from coal-fired to natural-gas-fired generation, reducing power sector NO_x, SO_2, and Hg emissions is projected to have some impact on CO_2 emissions (Figure 15). In 2010, CO_2 emissions in the analysis cases are projected to be between 14 million and 33 million metric tons below the level expected in the reference case. (The projections for CO_2 emissions are lower in the more stringent cases, because the expected shifts from coal to natural gas are larger.) In 2020, the range is slightly wider, between 12 million and 36 million metric tons. Even with these reductions, however, power sector CO_2 emissions in 2020 are projected to be between 262 million and 286 million metric tons (between 55 and 60 percent) above the 1990 level.

The potential exists for an increase in the use of coal and in its associated emissions in sectors of the economy (i.e., residential, commercial, and industrial) not covered by emission cap programs. However, because coal plays

Table 4. Key Projections in the Analysis Cases, 2010 and 2020

Projection	Reference Case	50-Percent Reduction Case	65-Percent Reduction Case	75-Percent Reduction Case
2010				
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.82	2.85	2.95	2.98
SO_2 Allowance Price (1999 Dollars per Ton)	180	210	415	296
NO_x Allowance Price: Annual (1999 Dollars per Ton)	0	1,208	1,491	2,072
NO_x Allowance Price: Seasonal (1999 Dollars per Ton)	4,404	0	0	0
Hg Allowance Price (1999 Dollars per Pound)	0	14,452	20,124	31,923
Electricity Price (1999 Cents per Kilowatthour)	6.12	6.12	6.23	6.23
Electricity Sales (Billion Kilowatthours)	4,133	4,135	4,122	4,120
Electricity Industry Revenues (Billion 1999 Dollars)	253	253	257	257
2020				
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	3.10	3.19	3.35	3.41
SO_2 Allowance Price (1999 Dollars per Ton)	200	719	1,390	1,737
NO_x Allowance Price: Annual (1999 Dollars per Ton)	0	1,108	1,457	2,825
NO_x Allowance Price: Seasonal (1999 Dollars per Ton)	5,087	0	0	0
Hg Allowance Price (1999 Dollars per Pound)	0	21,119	41,190	85,225
Electricity Price (1999 Cents per Kilowatthour)	6.13	6.22	6.35	6.48
Electricity Sales (Billion Kilowatthours)	4,763	4,749	4,736	4,716
Electricity Industry Revenues (Billion 1999 Dollars)	292	295	301	305

Note: The reference case assumes a 19-State summer season NO_x program beginning in 2004. The analysis cases assume the proposed annual programs without the summer limits.

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

[15]The changes in resource costs reported here do not include the financing and profits typically associated with new investments. If the changes in capital investments are put in the form of annuities, the changes in resource costs are $3.1 billion, $5.7 billion, and $7.2 billion in 2010 in the 50-, 65-, and 75-Percent cases, respectively. In 2020 the corresponding values are $4.8 billion, $9.1 billion, and $12.3 billion.

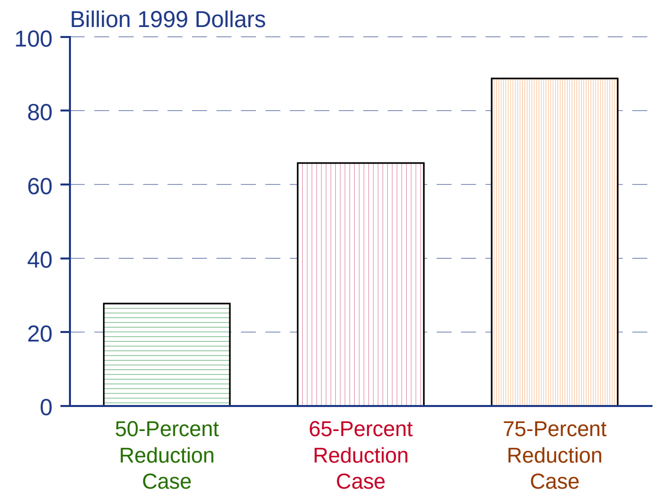
such a small role in those sectors and the projected decreases in coal prices are generally expected to be less than a few percent, the potential for emission "leakage" appears slight.[16] The increase in natural gas prices that is projected to occur because of increased use in the electricity sector appears to be more significant, leading to lower overall fuel consumption and lower emissions in the non-electricity sectors.

If a cap is imposed on power sector CO_2 emissions at the projected 2008 reference case level of 672 million metric tons (197 million metric tons or 41 percent above the 1990 level), power suppliers will have to either take action to reduce their emissions or purchase offsets for between 65 million and 89 million metric tons by 2020 (Figure 16). (Again, fewer offsets are required in the more stringent cases, because the expected shifts from coal to natural gas as a result of the other emission caps are larger.) Note that no offsets are required until projected CO_2 emissions in each of the three analysis cases exceed the assumed CO_2 cap (the 2008 level expected in the reference case), which is projected to occur in 2010 in the 50-Percent Reduction case, in 2012 in the 65-Percent Reduction case, and in 2013 in the 75-Percent Reduction case.

To determine the prices that U.S. power suppliers might be willing to pay for offsets, the three analysis cases were rerun with CO_2 emissions capped at the 2008 reference case level (Figure 17). The projected allowance prices in 2020 range between $33 and $54 per metric ton. As compared with earlier studies of the expected costs to the U.S. power sector of meeting the Kyoto Protocol requirements, these allowances prices are quite low; however, the CO_2 emissions cap assumed in this analysis (41 percent above the 1990 level) is very different from the U.S. target specified in the Kyoto agreement (7 percent below the 1990 level). The key CO_2 compliance strategy in these cases is expected to be a further shift from coal to natural-gas-fired generation. For example, in the 75-Percent Reduction case with no CO_2 cap, coal-fired generation in 2020 is projected to be 10 percent below the reference case level, and natural-gas-fired generation is projected to be 10 percent above the reference case level. In the 75-Percent Reduction case with a CO_2 cap set to the 2008 reference case level, the impacts are approximately doubled.

Because of the reduced reliance on coal projected in the cases with CO_2 caps, the investments in NO_x, SO_2, and Hg control equipment are projected to be lower. For example, scrubbers are projected to be added to nearly 152 gigawatts of capacity in the 75-Percent Reduction case without a CO_2 cap, as compared with only 115 gigawatts when the CO_2 cap is incorporated. In the early years of the projections, the expected investments in control equipment to reduce emissions of NO_x, SO_2, and Hg in the cases with and without CO_2 caps are similar; but they are much lower in the later years, when CO_2 emission caps are imposed. The projected allowance prices for NO_x and Hg are also lower when the CO_2 emissions cap is included.

Figure 13. Electricity Supplier Resource Costs: Projected Changes from the Reference Case in the Three Analysis Cases, 2001-2020



Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

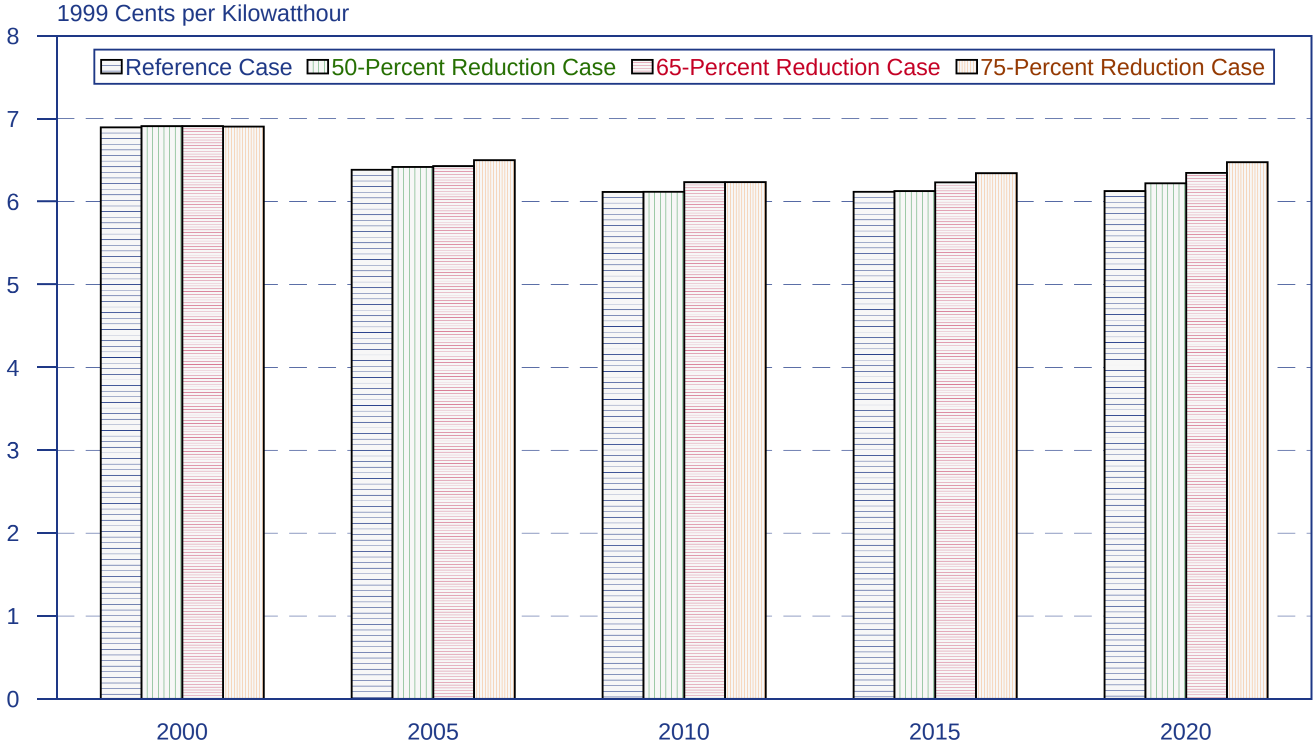
Table 5. Electricity Supplier Resource Costs: Projected Changes from the Reference Case in the Three Analysis Cases, 2001-2020

Analysis Case	Total Change (Billion 1999 Dollars)	Average Annual Change (Billion 1999 Dollars)	Total Change per Kilowatthour Generated (Percent)
50-Percent Reduction	28	1.4	1.5
65-Percent Reduction	66	3.3	3.5
75-Percent Reduction	89	4.4	4.8

Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

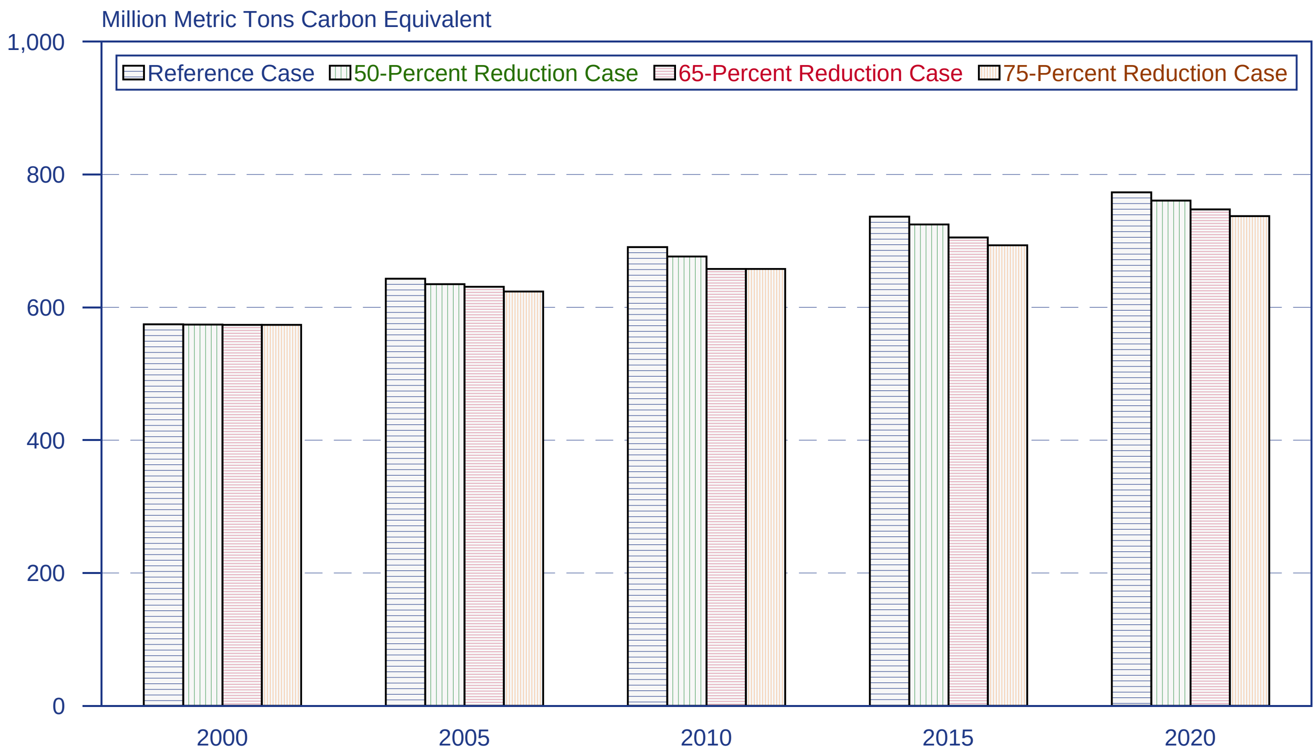
[16]Emission leakage occurs when control programs in a covered sector lead to actions that increase emissions in sectors not covered by the programs.

Figure 14. Projected Electricity Prices in Four Cases, 2000-2020



Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

Figure 15. Projected Electricity Generation Sector Carbon Dioxide Emissions in Four Cases, 2000-2020



Note: Does not include CO_2 emissions from cogenerators.

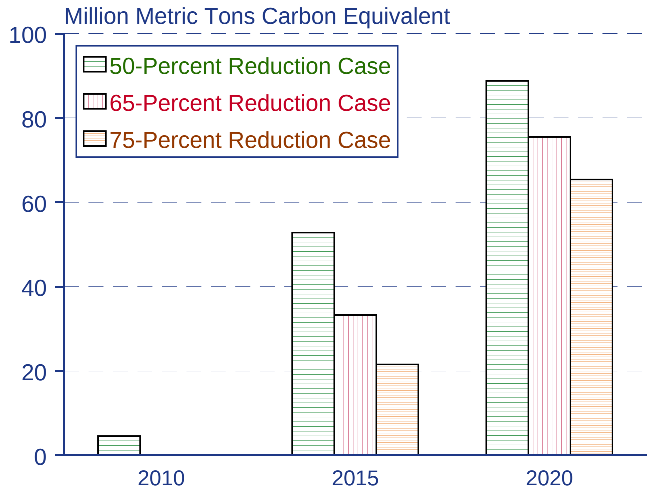
Source: National Energy Modeling System, runs SCENABS.D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512.D081701B (65-Percent Reduction), and RENC75.D081701B (75-Percent Reduction).

The projected CO_2 allowance prices in the cases with CO_2 caps represent the marginal cost of compliance within the U.S. power sector. They also represent the maximum price that power suppliers would be willing to pay for offsets. They would incur these costs only if they could not purchase offsets at a lower price. The price that U.S. power suppliers might have to pay to offset increases in CO_2 emissions above the 2008 reference case level is difficult to determine, because it would depend on what the rest of the world did in response to any greenhouse gas emissions reduction agreement. It would also depend on how offset programs were defined, implemented, and verified.

The National Energy Modeling System does not represent energy or non-energy markets outside the United States, and EIA has not made an independent assessment of how world offset markets might evolve. Figure 18 shows world energy sector CO_2 abatement supply curves (the upward sloping curves) produced by the Pacific Northwest Laboratory's Second Generation Model (SGM), matched against the projected requirement for reductions if all countries complied with the Kyoto Protocol (the vertical lines).[17]

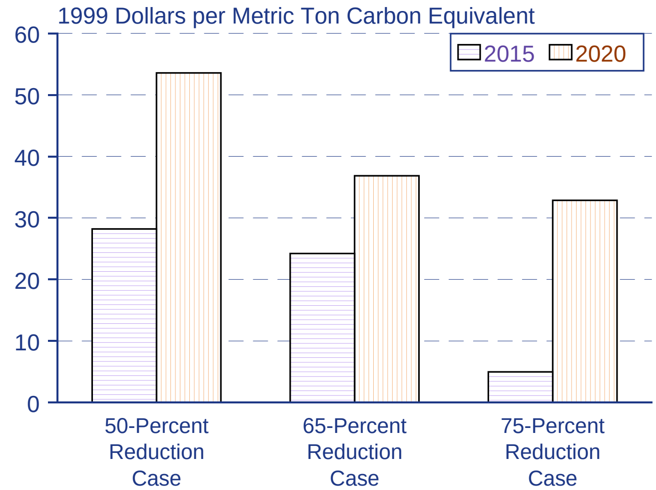
The supply curves in Figure 18 represent the projected CO_2 emission reductions (abatement) from reference case projections that would occur in the energy sectors of all countries in response to rising prices for carbon allowances. Because worldwide trading is assumed, all countries—including those without greenhouse gas reduction targets in the Kyoto Protocol—are included in the supply curves, assuming full compliance with the Kyoto Protocol. Countries with greenhouse gas reduction targets can trade with other countries by using the Protocol's clean development mechanism or joint implementation provisions. For example, if an Annex I country made investments that led to lower greenhouse gas emissions in China, the reductions would be counted toward the investing country's reduction target. The estimates include offsets created in each country's energy sector but exclude offsets that might be available from non-energy activities, such as changes in agricultural practices and reforestation activities. The reductions would be expected to come from numerous sources, including changes in fuel use, improvements in production efficiency (more efficient power plants), and reductions in consumer energy use.

Figure 16. Projected Carbon Offsets Required To Cap Power Sector Carbon Dioxide Emissions at the 2008 Reference Case Level in the Three Analysis Cases, 2010, 2015, and 2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

Figure 17. Projected Carbon Offset Prices with Power Sector Carbon Dioxide Emissions Capped at the 2008 Reference Case Level in the Three Analysis Cases, 2015 and 2020



Note: Does not include CO_2 emissions from cogenerators.
Source: National Energy Modeling System, runs SCENABS. D080301A (Reference), RENC5012.D081701B (50-Percent Reduction), RENC6512. D081701B (65-Percent Reduction), and RENC75. D081701B (75-Percent Reduction).

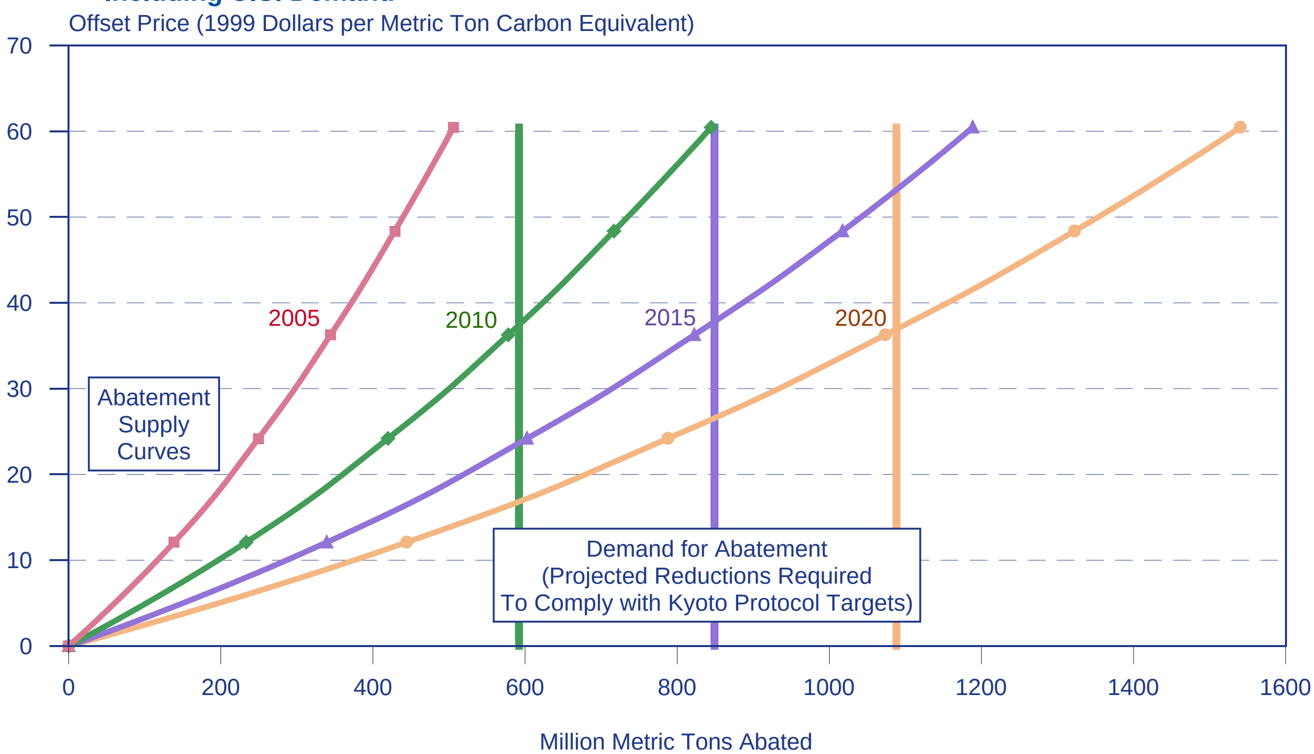
[17]The SGM supply and demand curves were modified to be consistent with the Energy Information Administration's *International Energy Outlook 2001*, DOE/EIA-0484(2001) (Washington, DC, March 2001). Essentially the percentage change in carbon emissions reflected in the SGM curves at different allowance prices was applied to the International Energy Outlook emissions projections for various parts of the world to develop revised abatement demand and supply curves. For more information on the SGM model, see J.A. Edmonds, H.M. Pitcher, D. Barns, R. Baron, and M.A. Wise, "Modeling Future Greenhouse Gas Emissions: The Second Generation Model Description," in *Modeling Global Change*, L.R. Klein and Fu-chen Lo, eds (New York, NY: United Nations University Press, 1993).

The demand curves represent the estimated reduction in carbon emissions required by Annex I countries to reach full compliance with the Kyoto Protocol. The United States is included in both the supply and demand curves in Figure 18, assuming full U.S. compliance with the Protocol. The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020. Both the supply of offsets and the demand for them are projected to grow over time as a result of expected economic growth and changing technologies.

Because this study does not assume U.S. participation in the Kyoto Protocol, adjustments were made to remove the U.S. contribution from the demand curves in Figure 18. Without U.S. participation in the Protocol, the demand for offsets would be much lower than depicted in Figure 18. For example, if the rest of the world complied with the Protocol while the United States did not, the world trading price for energy sector carbon allowances would be fairly low—rising from just a few dollars in 2010 to roughly $5 in 2015 and $8 in 2020 (Figure 19). The supply curves in Figure 19 are the same as those in Figure 18, but the demand curves have been shifted to the left (lowered), because the U.S. carbon reduction requirement has been removed. The price would rise slightly as U.S. power suppliers entered the market to purchase the 65 to 89 million metric tons of offsets they would need; however, assuming a price of roughly $10 per metric ton in 2020, the total cost of offsets for U.S. power suppliers would be between $654 million and $888 million in the three analysis cases.

The net result of the these estimates is that if power suppliers are required to purchase offsets for any CO_2 emissions above the level projected to be emitted in 2008 in the reference case, their costs in 2020 could rise by as little as $654 million or by as much as $888 million. The range in cost estimates results from the differences in offsets required in the three cases (between 65 million and 89 million metric tons carbon equivalent in 2020). The prices and costs could be lower if offsets from other greenhouse gases or carbon sinks were available. The analysis above is predicated on the assumption that the regional abatement costs curves provided by the SGM model are rreasonable estimates. Because we have no way to verify their reasonableness, that assumption increases the uncertainty of the cost estimates.

Figure 18. Worldwide Energy Sector Carbon Abatement Supply and Demand Curves, Including U.S. Demand



Note: The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020.

Source: Pacific Northwest Laboratory, Second Generation Model output (August 30, 2001).

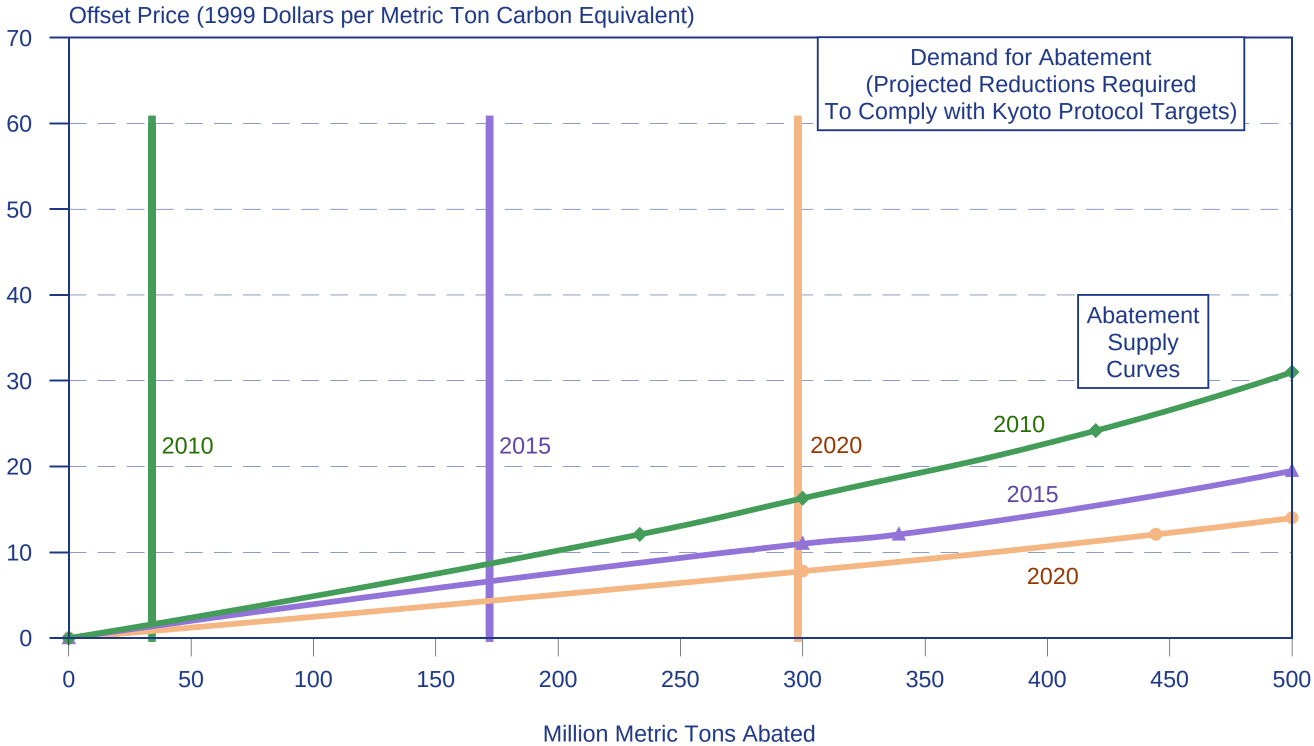
Uncertainties

As with any 20-year projections, there is considerable uncertainty about the results of this analysis. The potential role of new generating and emissions control technologies, future fuel prices, the possibility of market reliability problems as the emission reduction programs are phased in, the types of emission reduction programs established, and the impact on evolving electricity markets are especially uncertain. The evolution of new technologies is particularly unpredictable, and Hg emissions control technologies are relatively new and untested on a commercial scale. In addition, while a substantial amount of data about Hg emissions from coal-fired power plants has been collected in recent years, there still is considerable uncertainty in the measurement of Hg emissions and the extent to which control technologies designed primarily to remove NO_x or SO_2 might contribute to reducing Hg. It is possible that new, innovative technologies could be developed that would lower the costs of Hg removal, but it is also possible that reducing Hg substantially at some facilities may be more difficult than is presently expected with the limited data available. The emission caps studied in this analysis would likely stimulate additional research and development efforts for Hg control technologies.

An earlier EIA analysis examined several sensitivity cases, including ones with alternative emission caps, alternative technology assumptions, and alternative fuel price assumptions. The "high technology" Hg removal case suggested that if Hg control technologies improved significantly, the total and marginal costs of reducing Hg emissions could be much lower than shown here.[18]

One key uncertainty is the future price of natural gas. The vast majority of the new electricity generating capacity projected to be added over the next 20 years—more than 90 percent—is expected to be natural gas fired, producing relatively low NO_x emissions and virtually no SO_2 or Hg emissions. As a result, their addition and utilization would not create substantial upward pressure on emission allowance markets. If, however, natural gas prices turn out to be higher than projected, new coal-fired plants could become economically attractive, and their higher emission rates could increase the cost of meeting the emission caps and lead to higher electricity prices.

Figure 19. Worldwide Energy Sector Carbon Abatement Supply and Demand Curves, Excluding U.S. Demand



The intersections of the lines of the same color represent the prices at which the market for energy sector offsets would clear in 2010, 2015, and 2020.

Source: Pacific Northwest Laboratory, Second Generation Model output (August 30, 2001).

[18]For discussion of an enhanced Hg control technology case and other emission cap sensitivity cases, see 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/.

Because of the amount of emissions control equipment projected to be added, careful planning would be needed in all cases to ensure that the reliability of the electricity system would not be compromised during the transition period. System reliability could be of particular concern during the period when a large amount of emissions control equipment would have to be added. In many cases plants must be taken out of service when the final connections are made for new emissions control equipment. If extended outages resulted, or if power suppliers did not coordinate their outages to ensure that a large number of facilities would not be out of service at the same time, system interruptions could create the potential for price volatility in power markets.

There is also considerable uncertainty about the price of emission allowances that might evolve. There are numerous policy instruments—such as technical standards, taxes, free allowance cap and trade programs, auction-based cap and trade programs, and updating output-based allowance cap and trade programs—that could be used. The instrument chosen will affect the market response. In addition, because the different emission allowance markets are intertwined—actions taken to reduce one pollutant will impact the others—the design of each program will affect the others. Therefore, allowance prices could be very sensitive to program design issues. For CO_2 emissions, the potential price of offsets in world markets is very uncertain. Their price and availability will depend on the projected overall economic and energy market conditions in numerous countries over the next 20 years. In addition, the rules on what types of programs might be included in any trading program have yet to be finalized. This analysis only considered offsetting carbon emissions in world energy markets.

Finally, wholesale and retail electricity markets in the United States currently are undergoing significant change, moving from a long period of average cost regulated prices to a system in which power prices are set by market forces. The exact form that each of the regional markets will take is not known at this time. Changes in market structure as a result of the transition to competition could affect the choice of policy instruments needed to promote the efficient implementation of new emissions standards and the response by consumers to them. As mentioned above, a number of policy instruments are available. Each of the options would have different price and cost impacts. This study assumes that wholesale generation markets will behave competitively, and that any compliance costs that increase the operating costs of facilities setting the market price for power will be passed on to consumers. If the markets do not behave competitively, the cost and price changes could be different from those projected in this analysis.

Appendix A

Letter from the U.S. Senate Committee on Environment and Public Works

United States Senate

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

WASHINGTON, DC 20510-6175

June 8, 2001

Mr. John Weiner
Director, National Energy Information Center
Energy Information Administration (EIA), EI 30
1100 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Weiner:

We have read with interest the letter sent to you by Senator Jeffords and Senator Lieberman requesting additional analysis regarding the potential costs and cost efficiencies associated with an integrated, multi-emission control strategy for the nation's electricity sector. We agree that more analysis is needed, and we would expect you will be fully responsive to the request of our colleagues. At the same time, it seems that we need analysis of more viable policy options than is currently available, or would be reflected by your response to our colleagues' request.

Accordingly, we request that the Environmental Protection Agency (EPA) and the Energy Information Administration (EIA) analyze the scenarios described below as well as those requested by our colleagues. We believe that the pending debate in the Senate regarding this issue will be better served if we have an analysis covering a range of policy options. Only then will we be able to ensure that legislation amending the Clean Air Act (CAA) meets the multiple goals of 1) enabling the expansion of the electricity supply, 2) correcting the current over-reliance on natural gas as the fuel source for new electricity generation, 3) providing substantial regulatory relief from the requirements of the CAA, 4) ensuring that compliance costs are far below those anticipated from compliance with the current requirements of the CAA, and 5) achieving significant reductions of emissions from power plants.

We believe that the scenarios proposed by our colleagues, like those analyzed previously by EIA, do not reflect the best thinking about the potential to balance emission reductions with market flexibility and regulatory relief. Furthermore, the pending request to examine reduction of CO_2 to 1990 levels by 2007 will be largely redundant of previous EIA analysis. It seems obvious that such a policy would almost certainly result in abrupt and costly fuel switching. Also, it would be inconsistent with the President's stated goal of pursuing "innovative options for addressing concentrations of greenhouse gasses in the atmosphere". We believe the below scenarios would meet the President's desire to rely on technology development, market incentives and other creative means to address global climate change.

Each of the below scenarios would allow banking of emission allowances to begin in 2002 with the first half of the reduction required by 2007 and compliance with the full reduction by 2012. Full trading of NO_x and SO_2 should be assumed in a manner consistent with SO_2 trading in Title IV of the CAA. Half of the mercury reductions should be assumed to be available for trading, with half of the reductions required in each compliance period to be actual reductions made by each facility. Beyond the requirements of the listed scenarios, the analysis should assume no additional federal requirements to reduce emissions from the analyzed facilities.

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Scenario 1) Reduce NOx emissions by 75 percent below 1997 levels, SO2 emissions 75 percent below full implementation of Title IV of the CAA, mercury emissions by 75 percent below 1999 levels.

Scenario 2) Reduce NOx emissions by 65 percent below 1997 levels, SO2 emissions 65 percent below full implementation of Title IV of the CAA, mercury emissions by 65 percent below 1999 levels.

Scenario 3) Reduce NOx emissions by 50 percent below 1997 levels, SO2 emissions 50 percent below full implementation of Title IV of the CAA, mercury emissions by 50 percent below 1999 levels.

Carbon Dioxide

We do not support the strict regulation of CO2 emissions from power plants. We also agree with the President that Global Climate Change needs to be addressed, and we believe that a flexible plan, consistent with the President's direction, could be incorporated into a multi-emission bill. Accordingly, in addition to analyzing the above scenarios as described, each should be analyzed with the following CO2 requirement. Use EIA estimates for anticipated 2008 CO2 emission levels from the electricity sector. Assume emissions increases of CO2 after 2008 must be offset by reductions or sinks in any sector of any greenhouse gas in an amount equal to the warming potential of the emissions to be offset. Assume that verifiable reductions or sinks achieved in any nation could be available on the domestic emissions market to satisfy this requirement.

We would like this work to be conducted in a timeframe consistent with the analysis requested by Senator Jeffords and Senator Lieberman. This will enable us to debate any multi-emission strategy with a more robust understanding of the potential implications of various policy decisions. If you have any questions regarding this request, please contact Chris Hessler with Senator Smith at 224-9134 or Andrew Wheeler with Senator Voinovich at 224-0146. Thank you in advance for your cooperation.

Sincerely yours,

Bob Smith

Senator Bob Smith
Ranking Republican Member, Environment and Public Works Committee

Geo. V. Voinovich

Senator George Voinovich
Ranking Republican Member, Subcommittee on Clean Air, Wetlands, Private Property, and Nuclear Safety

Sam Brownback

Senator Sam Brownback

Appendix B

Tables for the 50-Percent Reduction Case

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Production										
Crude Oil and Lease Condensate	12.45	12.04	12.03	12.03	11.23	11.29	11.27	11.06	11.09	11.11
Natural Gas Plant Liquids	2.62	3.11	3.11	3.11	3.36	3.39	3.45	4.14	4.18	4.21
Dry Natural Gas	19.16	21.88	21.90	21.93	23.97	24.22	24.66	30.10	30.33	30.61
Coal	23.06	25.43	25.18	25.16	26.49	25.86	24.99	27.10	26.44	22.98
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.81
Renewable Energy[1]	6.52	7.09	7.18	7.28	7.86	7.94	8.18	8.37	8.50	9.30
Other[2]	1.65	0.35	0.35	0.35	0.30	0.30	0.30	0.33	0.33	0.33
Total	**73.26**	**77.79**	**77.65**	**77.76**	**80.90**	**80.74**	**80.64**	**87.61**	**87.42**	**85.34**
Imports										
Crude Oil[3]	18.96	21.42	21.42	21.42	22.49	22.43	22.45	25.91	25.84	25.93
Petroleum Products[4]	4.14	6.11	6.17	6.04	8.52	8.49	8.33	10.70	10.68	10.51
Natural Gas	3.63	5.14	5.14	5.13	5.55	5.59	5.62	6.55	6.59	6.65
Other Imports[5]	0.64	1.11	1.11	1.11	0.96	0.96	0.96	0.96	0.96	0.96
Total	**27.37**	**33.78**	**33.84**	**33.69**	**37.52**	**37.47**	**37.34**	**44.11**	**44.07**	**44.04**
Exports										
Petroleum[6]	1.98	1.73	1.74	1.73	1.73	1.71	1.70	1.82	1.83	1.89
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.43	0.43	0.63	0.63	0.63
Coal	1.48	1.51	1.52	1.52	1.45	1.46	1.46	1.41	1.41	1.45
Total	**3.62**	**3.56**	**3.58**	**3.58**	**3.61**	**3.59**	**3.59**	**3.87**	**3.87**	**3.97**
Discrepancy[7]	**0.67**	**0.44**	**0.42**	**0.45**	**0.06**	**0.06**	**0.09**	**0.18**	**0.13**	**0.13**
Consumption										
Petroleum Products[8]	37.92	41.21	41.29	41.14	44.30	44.35	44.24	50.36	50.37	50.26
Natural Gas	22.32	26.38	26.40	26.41	28.94	29.21	29.69	35.88	36.12	36.45
Coal	21.40	24.37	24.12	24.08	25.57	24.93	24.02	26.30	25.70	22.21
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.81
Renewable Energy[1]	6.53	7.10	7.18	7.28	7.87	7.94	8.19	8.38	8.51	9.31
Other[9]	0.35	0.61	0.61	0.61	0.38	0.38	0.38	0.25	0.25	0.25
Total	**96.33**	**107.56**	**107.49**	**107.43**	**114.74**	**114.55**	**114.31**	**127.68**	**127.49**	**125.28**
Net Imports - Petroleum	**21.12**	**25.80**	**25.86**	**25.72**	**29.28**	**29.22**	**29.07**	**34.78**	**34.70**	**34.55**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.22	20.83	20.83	20.83	21.37	21.37	21.37	22.41	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.99	3.02	2.99	2.82	2.85	2.92	3.10	3.19	3.28
Coal Minemouth Price (dollars per ton)	17.13	15.22	15.27	15.61	14.19	14.97	14.76	12.93	13.41	13.17
Average Electric Price (cents per Kwh)	6.7	6.4	6.4	6.4	6.1	6.1	6.2	6.1	6.2	7.1

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.80	0.80	0.76	0.76	0.76
Kerosene	0.10	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.46	0.46	0.46	0.43	0.43	0.43	0.41	0.41	0.41
Petroleum Subtotal	1.42	1.41	1.41	1.41	1.30	1.30	1.30	1.23	1.23	1.24
Natural Gas	4.88	5.55	5.55	5.55	5.54	5.54	5.52	6.08	6.06	6.05
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Electricity	3.91	4.56	4.55	4.56	4.91	4.91	4.89	5.69	5.66	5.50
Delivered Energy	**10.66**	**11.99**	**11.98**	**11.98**	**12.22**	**12.23**	**12.18**	**13.48**	**13.44**	**13.27**
Electricity Related Losses	8.44	9.66	9.57	9.62	10.00	9.89	9.85	10.65	10.58	9.94
Total	**19.10**	**21.65**	**21.55**	**21.60**	**22.22**	**22.11**	**22.04**	**24.14**	**24.02**	**23.21**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.37	0.37	0.37
Residual Fuel	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.60	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62
Natural Gas	3.14	3.99	3.99	3.99	4.19	4.18	4.17	4.47	4.45	4.48
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.66	4.40	4.39	4.40	4.92	4.91	4.91	5.64	5.62	5.47
Delivered Energy	**7.55**	**9.15**	**9.13**	**9.15**	**9.88**	**9.86**	**9.85**	**10.88**	**10.84**	**10.72**
Electricity Related Losses	7.91	9.33	9.21	9.29	10.02	9.90	9.90	10.56	10.50	9.89
Total	**15.46**	**18.48**	**18.34**	**18.44**	**19.90**	**19.77**	**19.75**	**21.44**	**21.35**	**20.61**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.22	1.21	1.30	1.30	1.30	1.49	1.49	1.49
Liquefied Petroleum Gas	2.32	2.44	2.45	2.43	2.51	2.53	2.52	2.85	2.85	2.85
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.27	0.27	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.25	0.25	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.41	4.45	4.42	4.68	4.70	4.68	5.00	5.03	5.02
Petroleum Subtotal	9.45	9.81	9.87	9.81	10.51	10.56	10.52	11.58	11.62	11.61
Natural Gas[6]	9.80	10.42	10.43	10.42	11.27	11.26	11.26	12.71	12.72	12.85
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.80	1.80	1.80	1.82	1.80	1.80	1.86	1.82	1.81
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.58	2.58	2.56	2.56	2.59	2.55	2.54
Renewable Energy[7]	2.15	2.40	2.42	2.40	2.63	2.64	2.63	3.07	3.08	3.08
Electricity	3.61	3.88	3.89	3.87	4.16	4.17	4.15	4.76	4.76	4.62
Delivered Energy	**27.56**	**29.10**	**29.21**	**29.09**	**31.14**	**31.19**	**31.13**	**34.72**	**34.72**	**34.68**
Electricity Related Losses	7.80	8.21	8.18	8.18	8.47	8.40	8.38	8.91	8.89	8.35
Total	**35.36**	**37.31**	**37.39**	**37.27**	**39.61**	**39.60**	**39.51**	**43.63**	**43.61**	**43.03**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Transportation										
Distillate Fuel	5.13	6.25	6.27	6.24	6.98	6.99	6.96	8.21	8.21	8.17
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Motor Gasoline[2]	15.92	17.64	17.68	17.64	18.94	18.97	18.94	21.25	21.27	21.23
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86
Liquefied Petroleum Gas	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	28.95	29.03	28.94	31.62	31.68	31.61	36.70	36.73	36.65
Pipeline Fuel Natural Gas	0.66	0.82	0.83	0.83	0.90	0.91	0.92	1.10	1.10	1.11
Compressed Natural Gas	0.02	0.05	0.06	0.05	0.09	0.09	0.09	0.16	0.16	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.09	0.09	0.09	0.12	0.12	0.12	0.17	0.17	0.17
Delivered Energy	**26.28**	**29.94**	**30.03**	**29.94**	**32.77**	**32.84**	**32.77**	**38.16**	**38.20**	**38.12**
Electricity Related Losses	0.13	0.19	0.19	0.19	0.24	0.24	0.24	0.31	0.31	0.30
Total	**26.41**	**30.12**	**30.21**	**30.12**	**33.01**	**33.07**	**33.01**	**38.47**	**38.51**	**38.42**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.70	8.74	8.70	9.46	9.47	9.44	10.82	10.83	10.79
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.03	3.01	3.07	3.09	3.08	3.41	3.41	3.42
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.25	19.22	21.56	21.58	21.54
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.23	1.23	1.24
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.97	5.33	5.36	5.35
Petroleum Subtotal	37.01	40.77	40.92	40.77	44.05	44.16	44.05	50.13	50.20	50.12
Natural Gas[6]	18.50	20.84	20.85	20.84	21.99	21.98	21.96	24.52	24.49	24.64
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.94	1.92	1.93	1.99	1.95	1.94
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.70	2.71	2.70	2.70	2.69	2.68	2.71	2.67	2.66
Renewable Energy[13]	2.65	2.93	2.94	2.93	3.17	3.18	3.17	3.64	3.64	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.24	12.93	12.92	12.92	14.10	14.11	14.07	16.25	16.20	15.75
Delivered Energy	**72.05**	**80.17**	**80.35**	**80.16**	**86.01**	**86.12**	**85.94**	**97.25**	**97.21**	**96.80**
Electricity Related Losses	24.28	27.39	27.14	27.27	28.73	28.43	28.37	30.43	30.29	28.48
Total	**96.33**	**107.56**	**107.49**	**107.43**	**114.74**	**114.55**	**114.31**	**127.68**	**127.49**	**125.28**
Electric Generators[14]										
Distillate Fuel	0.05	0.06	0.05	0.05	0.06	0.05	0.05	0.06	0.04	0.02
Residual Fuel	0.86	0.37	0.31	0.32	0.20	0.14	0.14	0.17	0.13	0.12
Petroleum Subtotal	0.91	0.43	0.36	0.37	0.25	0.19	0.19	0.23	0.17	0.14
Natural Gas	3.83	5.54	5.54	5.57	6.96	7.23	7.73	11.36	11.63	11.81
Steam Coal	18.75	21.67	21.41	21.38	22.87	22.25	21.34	23.59	23.03	19.55
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.81
Renewable Energy[15]	3.88	4.17	4.24	4.35	4.70	4.77	5.02	4.75	4.87	5.67
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**35.52**	**40.32**	**40.07**	**40.19**	**42.83**	**42.54**	**42.44**	**46.68**	**46.49**	**44.22**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Total Energy Consumption										
Distillate Fuel	7.53	8.77	8.79	8.75	9.51	9.52	9.49	10.88	10.87	10.81
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.03	3.01	3.07	3.09	3.08	3.41	3.41	3.42
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.25	19.22	21.56	21.58	21.54
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.92	1.48	1.41	1.42	1.39	1.34	1.34	1.41	1.36	1.36
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.97	5.33	5.36	5.35
Petroleum Subtotal	37.92	41.21	41.29	41.14	44.30	44.35	44.24	50.36	50.37	50.26
Natural Gas	22.32	26.38	26.40	26.41	28.94	29.21	29.69	35.88	36.12	36.45
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.59	23.59	23.33	23.30	24.81	24.17	23.26	25.58	24.98	21.48
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	21.40	24.37	24.12	24.08	25.57	24.93	24.02	26.30	25.70	22.21
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.81
Renewable Energy[17]	6.53	7.10	7.18	7.28	7.87	7.94	8.19	8.38	8.51	9.31
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**96.33**	**107.56**	**107.49**	**107.43**	**114.74**	**114.56**	**114.31**	**127.68**	**127.50**	**125.28**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.17	80.35	80.16	86.01	86.12	85.94	97.25	97.21	96.80
Total Energy Use	96.33	107.56	107.49	107.43	114.74	114.56	114.31	127.68	127.50	125.28
Population (millions)	273.13	288.02	288.02	288.02	300.17	300.17	300.17	325.24	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10908	10960	10906	12634	12667	12634	16509	16515	16511
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1701.4	1695.8	1692.6	1820.6	1807.9	1789.9	2043.8	2031.2	1944.5

[1]Includes wood used for residential heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass.
[4]Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1999 electric utility fuel consumption: Energy Information Administration, (EIA) *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Residential	**13.18**	**13.33**	**13.40**	**13.37**	**13.41**	**13.49**	**13.58**	**13.62**	**13.82**	**14.75**
Primary Energy[1]	6.71	7.50	7.53	7.51	7.17	7.19	7.25	7.01	7.09	7.14
Petroleum Products[2]	7.55	9.17	9.17	9.17	9.37	9.39	9.37	9.47	9.51	9.44
Distillate Fuel	6.27	7.37	7.38	7.38	7.57	7.57	7.57	7.76	7.79	7.74
Liquefied Petroleum Gas	10.36	12.61	12.61	12.61	12.82	12.86	12.83	12.71	12.78	12.65
Natural Gas	6.52	7.13	7.17	7.14	6.70	6.73	6.80	6.56	6.65	6.72
Electricity	23.69	22.29	22.44	22.37	22.19	22.34	22.49	22.16	22.54	24.92
Commercial	**13.28**	**12.71**	**12.78**	**12.76**	**12.23**	**12.20**	**12.36**	**12.55**	**12.70**	**14.10**
Primary Energy[1]	5.22	5.58	5.60	5.58	5.65	5.68	5.73	5.69	5.77	5.82
Petroleum Products[2]	4.99	6.08	6.08	6.08	6.27	6.27	6.26	6.37	6.40	6.35
Distillate Fuel	4.37	5.17	5.17	5.17	5.35	5.35	5.34	5.51	5.54	5.49
Residual Fuel	2.63	3.64	3.64	3.64	3.70	3.70	3.70	3.85	3.85	3.85
Natural Gas[3]	5.34	5.57	5.60	5.57	5.63	5.66	5.72	5.67	5.76	5.82
Electricity	21.64	20.28	20.42	20.37	18.76	18.66	18.92	18.83	19.04	21.93
Industrial[4]	**5.29**	**5.75**	**5.77**	**5.76**	**5.62**	**5.65**	**5.68**	**5.82**	**5.91**	**6.21**
Primary Energy	3.91	4.46	4.48	4.47	4.45	4.48	4.49	4.61	4.68	4.66
Petroleum Products[2]	5.54	5.97	5.97	5.97	6.07	6.11	6.08	6.12	6.15	6.07
Distillate Fuel	4.65	5.33	5.33	5.33	5.53	5.54	5.53	5.71	5.73	5.69
Liquefied Petroleum Gas	8.50	7.75	7.75	7.74	7.77	7.84	7.78	7.68	7.74	7.63
Residual Fuel	2.78	3.37	3.37	3.37	3.43	3.42	3.42	3.58	3.58	3.58
Natural Gas[5]	2.79	3.66	3.70	3.67	3.46	3.49	3.55	3.73	3.82	3.90
Metallurgical Coal	1.66	1.58	1.58	1.58	1.54	1.55	1.54	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.35	1.30	1.31	1.30	1.21	1.21	1.17
Electricity	13.12	12.81	12.87	12.87	12.04	12.00	12.17	12.07	12.31	14.56
Transportation	**8.30**	**9.33**	**9.34**	**9.34**	**9.63**	**9.63**	**9.65**	**9.20**	**9.20**	**9.23**
Primary Energy	8.29	9.32	9.32	9.32	9.61	9.61	9.64	9.18	9.18	9.20
Petroleum Products[2]	8.28	9.32	9.32	9.32	9.61	9.61	9.64	9.18	9.17	9.20
Distillate Fuel[6]	8.22	8.89	8.90	8.90	8.94	8.95	8.94	8.83	8.83	8.84
Jet Fuel[7]	4.70	5.22	5.24	5.23	5.49	5.49	5.49	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.21	11.25	10.60	10.59	10.63
Residual Fuel	2.46	3.11	3.10	3.11	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.08	14.07	14.00	14.05	14.02	13.64	13.70	13.57
Natural Gas[10]	7.02	7.30	7.33	7.31	7.17	7.20	7.28	7.30	7.38	7.45
Ethanol (E85)[11]	14.42	19.20	19.20	19.20	19.13	19.13	19.15	19.34	19.35	19.38
Methanol (M85)[12]	10.38	13.13	13.17	13.14	13.80	13.81	13.81	14.35	14.35	14.37
Electricity	15.64	14.61	14.64	14.56	13.73	13.69	13.94	13.18	13.39	14.49
Average End-Use Energy	**8.52**	**9.16**	**9.18**	**9.17**	**9.16**	**9.18**	**9.23**	**9.13**	**9.21**	**9.61**
Primary Energy	6.31	7.16	7.18	7.17	7.30	7.32	7.34	7.20	7.23	7.24
Electricity	19.58	18.71	18.81	18.79	17.93	17.93	18.13	17.96	18.23	20.74
Electric Generators[13]										
Fossil Fuel Average	1.48	1.63	1.65	1.64	1.59	1.62	1.70	1.85	1.91	2.07
Petroleum Products	2.48	3.60	3.64	3.62	3.96	4.09	4.09	4.20	4.36	4.29
Distillate Fuel	4.07	4.65	4.68	4.67	4.85	4.86	4.85	5.05	5.09	5.14
Residual Fuel	2.39	3.43	3.46	3.45	3.70	3.84	3.85	3.92	4.11	4.13
Natural Gas	2.57	3.42	3.49	3.46	3.23	3.31	3.39	3.62	3.72	3.88
Steam Coal	1.21	1.13	1.13	1.13	1.06	1.05	1.06	0.98	0.98	0.96

Table B3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Average Price to All Users[14]										
Petroleum Products[2]	7.46	8.48	8.49	8.49	8.75	8.77	8.78	8.49	8.50	8.50
Distillate Fuel	7.25	8.06	8.07	8.07	8.20	8.20	8.20	8.20	8.20	8.20
Jet Fuel	4.70	5.22	5.24	5.23	5.49	5.49	5.49	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.65	8.65	8.64	8.66	8.72	8.67	8.48	8.54	8.43
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.21	11.25	10.60	10.59	10.63
Residual Fuel	2.47	3.25	3.25	3.25	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.04	4.73	4.77	4.74	4.43	4.46	4.51	4.50	4.58	4.68
Coal	1.23	1.15	1.15	1.15	1.08	1.07	1.08	0.99	0.99	0.98
Ethanol (E85)[11]	14.42	19.20	19.20	19.20	19.13	19.13	19.15	19.34	19.35	19.38
Methanol (M85)[12]	10.38	13.13	13.17	13.14	13.80	13.81	13.81	14.35	14.35	14.37
Electricity	19.58	18.71	18.81	18.79	17.93	17.93	18.13	17.96	18.23	20.74
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	135.11	154.23	154.97	154.52	158.26	159.25	159.73	177.68	179.72	189.44
Commercial	99.11	115.32	115.67	115.64	119.82	119.33	120.75	135.53	136.67	150.03
Industrial	112.11	126.41	127.42	126.55	131.84	132.61	133.11	152.08	154.42	163.07
Transportation	212.64	271.38	272.23	271.35	306.12	306.82	306.91	340.13	340.36	340.73
Total Non-Renewable Expenditures	558.97	667.34	670.30	668.06	716.05	718.02	720.49	805.42	811.18	843.27
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.62	0.63	0.63	0.85	0.85	0.85
Total Expenditures	**559.11**	**667.75**	**670.72**	**668.48**	**716.67**	**718.65**	**721.11**	**806.27**	**812.03**	**844.12**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
NO_x = Nitrogen oxide.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2005 Reference	2005 50 Percent	2005 50 Percent with CO_2 Cap	2010 Reference	2010 50 Percent	2010 50 Percent with CO_2 Cap	2020 Reference	2020 50 Percent	2020 50 Percent with CO_2 Cap
Generation by Fuel Type										
Electric Generators[1]										
Coal	1830	2105	2080	2074	2238	2162	2066	2302	2221	1894
Petroleum	85	42	36	37	25	19	19	23	17	15
Natural Gas[2]	370	582	606	604	826	903	975	1488	1551	1653
Nuclear Power	730	740	740	740	720	725	729	610	613	637
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	372	377	381	396	399	407	399	407	468
Total	**3369**	**3839**	**3838**	**3836**	**4204**	**4207**	**4195**	**4821**	**4809**	**4666**
Non-Utility Generation for Own Use	16	17	17	17	17	16	16	16	16	23
Distributed Generation	0	0	0	0	1	1	1	5	5	4
Cogenerators[4]										
Coal	47	53	52	52	51	51	51	52	49	47
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	236	237	237	259	258	258	317	317	361
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	9
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	6	5	6
Total	**303**	**344**	**345**	**345**	**372**	**370**	**370**	**440**	**438**	**479**
Other End-Use Generators	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	172	171	171	179	177	177	208	205	212
Generation for Own Use	156	177	179	178	197	198	198	237	238	272
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1337	1335	1335	1438	1438	1432	1668	1659	1611
Commercial	1073	1291	1286	1289	1442	1440	1439	1653	1647	1603
Industrial	1058	1137	1141	1135	1219	1222	1217	1394	1394	1353
Transportation	17	26	26	26	34	35	34	49	49	49
Total	**3294**	**3790**	**3788**	**3785**	**4133**	**4135**	**4123**	**4763**	**4749**	**4615**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.1	7.6	7.7	7.6	7.6	7.6	7.7	7.6	7.7	8.5
Commercial	7.4	6.9	7.0	6.9	6.4	6.4	6.5	6.4	6.5	7.5
Industrial	4.5	4.4	4.4	4.4	4.1	4.1	4.2	4.1	4.2	5.0
Transportation	5.3	5.0	5.0	5.0	4.7	4.7	4.8	4.5	4.6	4.9
All Sectors Average	**6.7**	**6.4**	**6.4**	**6.4**	**6.1**	**6.1**	**6.2**	**6.1**	**6.2**	**7.1**
Prices by Service Category[9] (1999 cents/kwh)										
Generation	4.1	3.8	3.9	3.9	3.4	3.4	3.5	3.5	3.6	4.4
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.49	10.39	8.77	8.76	9.70	6.90	6.90	8.95	4.47	4.48
Nitrogen Oxide	5.43	4.30	4.56	4.57	4.34	3.63	3.65	4.48	3.17	2.90

Columns 2005, 2010 and 2020 are Projections.

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2]Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.8	302.8	317.8	312.0	297.6	317.3	310.0	291.9
Other Fossil Steam[3]	137.4	124.9	121.2	119.0	117.4	108.0	106.7	114.9	107.4	105.0
Combined Cycle	21.0	52.4	67.8	62.8	107.3	133.2	139.4	199.0	215.4	224.5
Combustion Turbine/Diesel	86.8	126.4	119.3	123.6	149.8	142.5	148.6	197.4	195.8	179.4
Nuclear Power	97.4	97.5	97.5	97.5	93.7	94.8	95.3	76.3	76.3	80.7
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	88.8	94.7	94.9	95.4	97.9	98.3	99.4	99.4	99.8	101.2
Distributed Generation[5]	0.0	0.8	0.4	0.4	2.5	2.3	2.5	11.0	10.6	8.9
Total	**755.9**	**820.0**	**824.3**	**820.9**	**906.0**	**910.7**	**909.2**	**1035.1**	**1035.1**	**1011.4**
Cumulative Planned Additions[6]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Combustion Turbine/Diesel	0.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	5.1	5.1	5.1	6.7	6.7	6.7	8.1	8.1	8.1
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**32.0**	**32.0**	**32.0**	**33.7**	**33.7**	**33.7**	**35.3**	**35.3**	**35.3**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	1.1	1.0	0.0	18.2	14.2	0.0	19.5	14.5	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	18.6	34.0	29.0	73.6	99.5	105.8	165.4	181.8	190.9
Combustion Turbine/Diesel	0.0	30.9	19.7	24.2	55.4	44.1	50.3	103.1	97.5	81.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	0.6	1.1	1.9	2.3	3.4	1.9	2.4	3.7
Distributed Generation[5]	0.0	0.8	0.4	0.4	2.5	2.3	2.5	11.0	10.6	8.9
Total	**0.0**	**51.7**	**55.6**	**54.7**	**151.5**	**162.5**	**161.9**	**300.8**	**306.7**	**285.0**
Cumulative Total Additions	**0.0**	**83.7**	**87.6**	**86.7**	**185.2**	**196.1**	**195.6**	**336.1**	**342.0**	**320.3**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.5	7.3	7.5	7.3	9.6	13.2
Other Fossil Steam[3]	0.0	12.7	16.5	18.7	20.2	29.7	31.0	22.7	30.2	32.6
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2
Combustion Turbine/Diesel	0.0	5.5	5.7	5.9	6.6	7.0	7.0	6.7	7.1	7.4
Nuclear Power	0.0	0.0	0.0	0.0	3.7	2.6	2.2	21.2	21.2	16.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	0.0	20.6	24.7	27.1	36.4	46.9	47.9	58.1	68.4	70.4
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	8.1	8.1	8.6	7.7	7.5
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Natural Gas	34.6	39.7	40.0	39.9	43.1	43.2	43.2	51.2	51.4	57.3
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.1	1.1
Renewable Sources[4]	5.4	5.9	5.9	5.9	6.8	6.8	6.8	8.3	8.2	8.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.1**	**59.3**	**59.3**	**63.1**	**62.7**	**62.8**	**73.0**	**72.2**	**78.1**
Cumulative Additions[6]	**0.0**	**6.7**	**6.9**	**6.9**	**10.7**	**10.3**	**10.3**	**20.5**	**19.8**	**25.6**

Table B5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Other End-Use Generators[9]										
Renewable Sources	1.0	1.1	1.1	1.1	1.3	1.3	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on EIA-860B: "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	182.2	125.3	125.3	125.3	102.9	102.9	102.9	0.0	0.0	0.0
Gross Domestic Economy Trade	152.1	199.1	208.5	202.7	154.6	128.4	135.6	146.4	118.0	98.3
Gross Domestic Trade	**334.3**	**324.4**	**333.8**	**328.0**	**257.5**	**231.3**	**238.6**	**146.4**	**118.0**	**98.3**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.8	5905.8	5905.8	4851.2	4851.2	4851.2	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4204.3	6352.8	6771.8	6596.1	4407.4	3726.7	4032.8	4448.7	3776.2	4002.7
Gross Domestic Sales (million 1999 dollars)	**12792.4**	**12258.6**	**12677.6**	**12501.9**	**9258.7**	**8578.0**	**8884.0**	**4448.7**	**3776.2**	**4002.7**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	10.7	5.8	5.8	5.8	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	21.9	63.5	63.5	63.5	45.9	45.9	45.9	30.6	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**74.1**	**74.1**	**74.1**	**51.7**	**51.7**	**51.7**	**30.6**	**30.6**	**30.6**
Firm Power Exports To Canada and Mexico	9.2	9.7	9.7	9.7	8.7	8.7	8.7	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.0	7.0	7.0	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.7**	**16.7**	**16.7**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Production										
Dry Gas Production[1]	18.67	21.32	21.35	21.37	23.36	23.60	24.04	29.34	29.56	29.83
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.70**	**4.70**	**4.69**	**5.01**	**5.04**	**5.06**	**5.78**	**5.81**	**5.87**
Canada	3.29	4.49	4.48	4.48	4.72	4.75	4.78	5.39	5.42	5.47
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	-0.25	-0.25	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	0.53	0.53	0.79	0.79	0.80
Total Supply	**22.15**	**26.14**	**26.16**	**26.18**	**28.42**	**28.70**	**29.16**	**35.17**	**35.43**	**35.75**
Consumption by Sector										
Residential	4.75	5.40	5.40	5.40	5.39	5.40	5.37	5.92	5.90	5.89
Commercial	3.06	3.89	3.88	3.89	4.08	4.07	4.06	4.36	4.33	4.36
Industrial[3]	8.31	8.78	8.80	8.78	9.48	9.46	9.44	10.52	10.51	10.63
Electric Generators[4]	3.76	5.44	5.44	5.47	6.83	7.09	7.58	11.15	11.41	11.59
Lease and Plant Fuel[5]	1.23	1.36	1.36	1.36	1.50	1.51	1.53	1.86	1.87	1.88
Pipeline Fuel	0.64	0.80	0.81	0.81	0.88	0.89	0.90	1.07	1.08	1.08
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.77**	**25.73**	**25.75**	**25.76**	**28.24**	**28.50**	**28.97**	**35.03**	**35.26**	**35.58**
Discrepancy[7]	**0.38**	**0.41**	**0.41**	**0.41**	**0.19**	**0.20**	**0.19**	**0.15**	**0.17**	**0.17**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B8. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.99	3.02	2.99	2.82	2.85	2.92	3.10	3.19	3.28
Average Import Price	2.29	2.99	2.99	2.98	2.66	2.67	2.68	2.71	2.73	2.75
Average[2]	**2.11**	**2.99**	**3.02**	**2.99**	**2.79**	**2.82**	**2.88**	**3.03**	**3.11**	**3.18**
Delivered Prices										
Residential	6.69	7.33	7.36	7.33	6.88	6.91	6.98	6.74	6.83	6.90
Commercial	5.49	5.72	5.75	5.72	5.78	5.81	5.88	5.82	5.91	5.98
Industrial[3]	2.87	3.76	3.79	3.77	3.55	3.58	3.65	3.84	3.93	4.00
Electric Generators[4]	2.62	3.49	3.56	3.52	3.30	3.37	3.45	3.68	3.79	3.95
Transportation[5]	7.21	7.50	7.53	7.51	7.36	7.40	7.47	7.50	7.58	7.65
Average[6]	**4.14**	**4.85**	**4.89**	**4.86**	**4.55**	**4.58**	**4.63**	**4.61**	**4.70**	**4.80**
Transmission & Distribution Margins[7]										
Residential	4.58	4.34	4.34	4.34	4.09	4.10	4.11	3.71	3.72	3.72
Commercial	3.37	2.73	2.73	2.73	2.99	3.00	3.00	2.79	2.80	2.80
Industrial[3]	0.76	0.78	0.78	0.78	0.76	0.76	0.77	0.81	0.82	0.82
Electric Generators[4]	0.51	0.50	0.54	0.53	0.51	0.56	0.58	0.66	0.68	0.77
Transportation[5]	5.10	4.52	4.51	4.52	4.57	4.58	4.60	4.47	4.48	4.47
Average[6]	**2.03**	**1.87**	**1.88**	**1.87**	**1.76**	**1.76**	**1.75**	**1.59**	**1.59**	**1.62**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.45	23.48	23.47	22.07	22.11	22.07	21.95	21.99	21.92
Commercial	10.32	10.62	10.61	10.63	12.19	12.19	12.17	12.16	12.15	12.19
Industrial[3]	6.28	6.82	6.86	6.85	7.20	7.23	7.27	8.50	8.61	8.72
Electric Generators[4]	1.90	2.74	2.95	2.92	3.46	3.95	4.36	7.33	7.81	8.93
Transportation[5]	0.08	0.24	0.24	0.24	0.40	0.41	0.41	0.68	0.68	0.67
Total	**40.35**	**43.87**	**44.15**	**44.10**	**45.33**	**45.89**	**46.27**	**50.61**	**51.23**	**52.44**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1999 values, and projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.48**	**21.41**	**21.43**	**20.80**	**20.78**	**20.81**	**21.50**	**21.48**	**21.45**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.69**	**5.68**	**5.68**	**5.30**	**5.34**	**5.32**	**5.22**	**5.24**	**5.25**
Lower 48 Onshore	3.27	2.80	2.81	2.80	2.50	2.51	2.50	2.71	2.74	2.74
Conventional	2.59	2.18	2.18	2.18	1.81	1.81	1.81	1.96	1.97	1.98
Enhanced Oil Recovery	0.68	0.62	0.63	0.62	0.69	0.70	0.69	0.74	0.77	0.76
Lower 48 Offshore	1.56	2.09	2.09	2.09	2.16	2.18	2.18	1.88	1.86	1.87
Alaska	1.05	0.79	0.79	0.79	0.65	0.65	0.65	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.76**	**15.78**	**15.76**	**14.43**	**14.54**	**14.49**	**14.01**	**14.10**	**14.11**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.99**	**3.02**	**2.99**	**2.82**	**2.85**	**2.92**	**3.10**	**3.19**	**3.28**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.32**	**21.35**	**21.37**	**23.36**	**23.60**	**24.04**	**29.34**	**29.56**	**29.83**
Lower 48 Onshore	12.83	14.37	14.40	14.42	16.42	16.62	17.02	21.10	21.42	21.56
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.32	1.32	1.38	1.39	1.39
Non-Associated	11.03	12.86	12.89	12.90	15.10	15.29	15.70	19.72	20.03	20.17
Conventional	6.64	7.62	7.63	7.63	7.79	7.85	8.11	11.05	11.13	11.12
Unconventional	4.39	5.24	5.26	5.27	7.30	7.44	7.59	8.66	8.91	9.05
Lower 48 Offshore	5.43	6.49	6.48	6.49	6.44	6.48	6.51	7.66	7.57	7.70
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.04	1.04
Non-Associated	4.50	5.42	5.42	5.43	5.35	5.39	5.42	6.63	6.54	6.66
Alaska	0.42	0.47	0.47	0.47	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**169.38**	**168.97**	**169.20**	**184.15**	**187.08**	**186.35**	**199.35**	**199.42**	**199.67**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.93**	**29.02**	**29.07**	**29.00**	**29.30**	**29.92**	**30.33**	**38.07**	**38.57**	**39.89**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC. June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Production[1]										
Appalachia	434	432	425	435	425	427	415	396	398	358
Interior	182	185	178	182	183	186	169	164	160	132
West	486	612	610	589	681	625	613	775	726	625
East of the Mississippi	558	569	560	574	564	574	548	526	534	464
West of the Mississippi	544	659	653	632	725	664	649	810	749	650
Total	**1102**	**1228**	**1213**	**1206**	**1289**	**1238**	**1197**	**1336**	**1284**	**1115**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	58	58	56	56	58
Total	**-49**	**-44**	**-45**	**-45**	**-40**	**-40**	**-40**	**-36**	**-36**	**-38**
Total Supply[2]	**1053**	**1184**	**1168**	**1162**	**1249**	**1197**	**1157**	**1300**	**1247**	**1077**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	82	82	85	83	83
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	920	1073	1057	1050	1139	1088	1046	1190	1142	972
Total	**1031**	**1185**	**1169**	**1162**	**1250**	**1198**	**1156**	**1299**	**1249**	**1079**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-0**	**-1**	**-1**	**1**	**1**	**-2**	**-3**
Average Minemouth Price										
(1999 dollars per short ton)	17.13	15.22	15.27	15.61	14.19	14.97	14.76	12.93	13.41	13.17
(1999 dollars per million Btu)	0.82	0.74	0.74	0.75	0.69	0.72	0.71	0.64	0.65	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.37	29.65	29.58	29.67	28.56	28.79	28.51	26.49	26.35	25.63
Coke Plants	44.38	42.40	42.41	42.42	41.25	41.45	41.36	38.50	38.64	38.55
Electric Generators										
(1999 dollars per short ton)	24.69	22.92	22.98	23.10	21.26	21.53	21.72	19.34	19.69	19.33
(1999 dollars per million Btu)	1.21	1.13	1.13	1.13	1.06	1.05	1.06	0.98	0.98	0.96
Average	**25.74**	**23.80**	**23.87**	**23.98**	**22.11**	**22.41**	**22.59**	**20.09**	**20.42**	**20.15**
Exports[7]	37.50	36.41	36.31	36.26	35.57	35.81	35.67	33.07	33.07	32.63

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data based on Energy Information Administration (EIA), *Quarterly Coal Report* , DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap	Reference	50 Percent	50 Percent with CO_2 Cap
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.26	79.26	79.38	79.38	79.38	79.38	79.38	79.38
Geothermal[2]	2.87	3.36	3.45	3.84	4.81	5.03	6.08	4.83	5.05	6.10
Municipal Solid Waste[3]	2.61	2.96	3.11	3.20	3.42	3.65	3.65	3.93	4.16	4.18
Wood and Other Biomass[4]	1.57	1.75	1.75	1.75	2.12	2.12	2.12	2.45	2.45	2.60
Solar Thermal	0.33	0.35	0.35	0.35	0.40	0.40	0.40	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.66	6.92	6.92	6.92	7.52	7.52	7.52	7.74	7.76	7.89
Total	**88.83**	**94.68**	**94.92**	**95.40**	**97.85**	**98.30**	**99.35**	**99.35**	**99.82**	**101.17**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.20	301.20	301.13	301.13	301.12	300.06	300.06	300.03
Geothermal[2]	13.21	17.71	18.50	21.71	29.92	31.71	40.42	30.13	31.95	40.61
Municipal Solid Waste[3]	18.12	20.68	21.85	22.58	23.88	25.68	25.69	27.76	29.56	29.68
Wood and Other Biomass[4]	8.76	14.92	18.23	18.24	21.22	20.23	19.63	19.29	23.59	75.39
Dedicated Plants	7.73	9.17	9.17	9.17	11.36	11.36	11.36	13.82	13.82	14.90
Cofiring	1.03	5.75	9.06	9.07	9.86	8.87	8.26	5.47	9.77	60.50
Solar Thermal	0.89	0.96	0.96	0.96	1.11	1.11	1.11	1.37	1.37	1.37
Solar Photovoltaic	0.03	0.20	0.20	0.20	0.51	0.51	0.51	1.36	1.36	1.36
Wind	4.61	16.30	16.30	16.30	18.16	18.16	18.16	18.77	18.83	19.25
Total	**355.16**	**371.97**	**377.23**	**381.18**	**395.92**	**398.53**	**406.64**	**398.74**	**406.72**	**467.69**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.19	5.17	5.19	6.09	6.06	6.10	7.59	7.54	7.59
Total	**5.35**	**5.89**	**5.87**	**5.89**	**6.79**	**6.76**	**6.80**	**8.29**	**8.24**	**8.29**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04
Biomass	27.08	30.04	29.92	30.04	35.20	35.01	35.20	43.82	43.52	43.83
Total	**31.12**	**34.08**	**33.97**	**34.08**	**39.24**	**39.05**	**39.25**	**47.87**	**47.57**	**47.88**
Other End-Use Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.10	0.10	0.10	0.35	0.35	0.35	0.35	0.35	0.35
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.44	4.44	4.44	4.43	4.43	4.43	4.41	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.20	0.20	0.20	0.75	0.75	0.75	0.75	0.75	0.75
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.17**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	2005 Reference	2005 50 Percent	2005 50 Percent with CO_2 Cap	2010 Reference	2010 50 Percent	2010 50 Percent with CO_2 Cap	2020 Reference	2020 50 Percent	2020 50 Percent with CO_2 Cap
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.43**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.40**	**2.42**	**2.40**	**2.63**	**2.64**	**2.63**	**3.07**	**3.08**	**3.08**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.22	2.23	2.22	2.44	2.45	2.44	2.89	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.21	0.21	0.21
Electric Generators[5]	**3.88**	**4.17**	**4.24**	**4.35**	**4.70**	**4.77**	**5.02**	**4.75**	**4.87**	**5.67**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.10	3.10	3.10	3.08	3.08	3.08
Geothermal	0.28	0.42	0.45	0.55	0.82	0.87	1.13	0.82	0.88	1.14
Municipal Solid Waste[6]	0.25	0.28	0.30	0.31	0.32	0.35	0.35	0.38	0.40	0.40
Biomass	0.11	0.18	0.21	0.21	0.25	0.24	0.24	0.24	0.29	0.82
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.14	0.14	0.17	0.17	0.16
Cofiring	0.01	0.07	0.11	0.11	0.12	0.11	0.10	0.07	0.12	0.66
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.17	0.17	0.17	0.19	0.19	0.19	0.19	0.19	0.20
Total Marketed Renewable Energy	**6.64**	**7.27**	**7.36**	**7.46**	**8.05**	**8.12**	**8.37**	**8.58**	**8.71**	**9.50**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol										
From Corn	0.12	0.19	0.19	0.19	0.19	0.19	0.19	0.17	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility," and EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A

Table B13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections 2005 Reference	2005 50 Percent	2005 50 Percent with CO_2 Cap	2010 Reference	2010 50 Percent	2010 50 Percent with CO_2 Cap	2020 Reference	2020 50 Percent	2020 50 Percent with CO_2 Cap
Residential										
Petroleum	26.0	26.6	26.6	26.6	24.6	24.6	24.6	23.3	23.3	23.4
Natural Gas	69.5	79.9	79.9	79.9	79.8	79.8	79.5	87.5	87.3	87.2
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	226.8	223.8	223.8	240.3	235.3	229.5	270.7	265.8	235.1
Total	**290.1**	**334.5**	**331.5**	**331.5**	**346.0**	**341.0**	**334.9**	**382.7**	**377.7**	**346.9**
Commercial										
Petroleum	13.7	11.9	11.9	11.9	12.1	12.1	12.1	12.0	12.1	12.1
Natural Gas	45.4	57.5	57.4	57.5	60.3	60.2	60.0	64.4	64.1	64.5
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	219.0	215.5	216.1	241.0	235.6	230.7	268.3	263.8	233.9
Total	**242.1**	**290.1**	**286.5**	**287.2**	**315.1**	**309.7**	**304.6**	**346.6**	**341.9**	**312.4**
Industrial[1]										
Petroleum	104.2	98.8	99.4	98.7	104.6	105.2	104.8	113.0	113.3	113.3
Natural Gas[2]	141.6	147.7	148.0	147.8	159.5	159.5	159.5	180.1	180.4	182.3
Coal	55.9	65.6	65.7	65.5	65.4	65.0	65.0	65.6	64.6	64.3
Electricity	178.8	192.9	191.3	190.2	203.7	200.0	195.1	226.3	223.3	197.4
Total	**480.4**	**505.0**	**504.4**	**502.3**	**533.2**	**529.7**	**524.4**	**585.0**	**581.6**	**557.4**
Transportation										
Petroleum[3]	485.8	554.7	556.3	554.6	606.2	607.3	605.9	703.5	704.1	702.5
Natural Gas[4]	9.5	12.6	12.7	12.7	14.3	14.4	14.6	18.0	18.1	18.1
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.3	4.3	5.8	5.7	5.5	7.9	7.8	7.1
Total[3]	**498.2**	**571.8**	**573.4**	**571.7**	**626.3**	**627.5**	**626.1**	**729.5**	**730.1**	**727.8**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	692.0	694.2	691.8	747.4	749.2	747.4	851.8	852.7	851.3
Natural Gas	266.0	297.8	298.0	297.9	313.9	313.9	313.6	350.0	350.0	352.1
Coal	58.8	68.5	68.7	68.5	68.6	68.1	68.1	68.8	67.7	67.5
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	643.1	634.9	634.4	690.7	676.5	660.8	773.1	760.7	673.5
Total[3]	**1510.8**	**1701.4**	**1695.8**	**1692.6**	**1820.6**	**1807.9**	**1789.9**	**2043.8**	**2031.2**	**1944.5**
Electric Generators[6]										
Petroleum	20.0	9.1	7.6	7.9	5.3	3.9	4.0	4.8	3.5	3.0
Natural Gas	45.8	79.8	79.8	80.2	100.2	104.0	111.3	163.6	167.5	170.1
Coal	490.5	554.2	547.4	546.3	585.3	568.6	545.5	604.7	589.8	500.4
Total	**556.3**	**643.1**	**634.9**	**634.4**	**690.7**	**676.5**	**660.8**	**773.1**	**760.7**	**673.5**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	701.1	701.9	699.7	752.6	753.1	751.3	856.5	856.2	854.3
Natural Gas	311.8	377.5	377.8	378.1	414.0	418.0	424.9	513.6	517.4	522.2
Coal	549.3	622.7	616.1	614.8	653.8	636.7	613.7	673.5	657.5	567.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1701.4**	**1695.8**	**1692.6**	**1820.6**	**1807.9**	**1789.9**	**2043.8**	**2031.2**	**1944.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.0**	**6.0**	**6.3**	**6.2**	**6.0**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99), (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Table B14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	2005 Reference	2005 50 Percent	2005 50 Percent with CO_2 Cap	2010 Reference	2010 50 Percent	2010 50 Percent with CO_2 Cap	2020 Reference	2020 50 Percent	2020 50 Percent with CO_2 Cap
		Projections								
Emissions										
Nitrogen Oxide (million tons)	5.43	4.30	4.56	4.57	4.34	3.63	3.65	4.48	3.17	2.90
Sulfur Dioxide (million tons)	13.49	10.39	8.77	8.76	9.70	6.90	6.90	8.95	4.47	4.48
Mercury (tons)	43.35	45.02	37.90	37.90	45.53	25.80	25.80	45.23	21.50	21.50
Carbon Dioxide (million metric tons carbon equivalent)	556.3	643.1	634.9	634.4	690.7	676.5	660.8	773.1	760.7	673.5
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)										
Summer Seasonal	0	4370	0	0	4404	0	0	5087	0	0
National Annual	0	0	772	807	0	1208	1162	0	1108	0
Sulfur Dioxide (1999 dollars per ton)	0	184	201	197	180	210	260	200	719	527
Mercury (million 1999 dollars per ton)	0	0	57	57	0	29	25	0	42	15
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	54
Retrofits (gigawatts, cumulative from 1999)										
Scrubber [1]	0.0	8.9	21.3	25.6	8.9	47.8	40.2	17.5	90.0	60.4
Combustion	0.0	40.4	31.5	31.8	42.5	47.2	48.5	46.6	53.8	52.4
SCR Post-combustion	0.0	90.8	0.1	0.9	90.9	46.6	43.1	91.1	98.0	84.4
SNCR Post-combustion	0.0	28.5	0.9	0.4	28.5	2.7	4.1	46.0	14.6	17.8
Mercury Spray Cooler	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0
Mercury Fabric Filter	0.0	0.0	0.0	0.0	0.0	45.5	47.2	0.0	45.5	47.2
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	473	582	591	568	633	588	585	714	684	599
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433	456	442	445	465	455	429	442	410	352
High Sulfur (> 1.67 lbs. S/mmBtu)	196	190	180	193	191	195	184	180	189	164

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
CO_2 = Carbon dioxide.
lbs. S/mmBtu = Pounds sulfur per million British thermal units.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC5012.D081701B, REWC5012.D081701A.

Appendix C

Tables for the 65-Percent Reduction Case

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Production										
Crude Oil and Lease Condensate	12.45	12.04	12.04	12.03	11.23	11.29	11.22	11.06	11.15	11.10
Natural Gas Plant Liquids	2.62	3.11	3.12	3.12	3.36	3.46	3.49	4.14	4.22	4.30
Dry Natural Gas	19.16	21.88	21.99	21.97	23.97	24.74	24.90	30.10	30.67	31.23
Coal	23.06	25.43	25.01	24.84	26.49	24.85	24.37	27.10	25.64	22.40
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.74
Renewable Energy[1]	6.52	7.09	7.18	7.25	7.86	7.97	8.23	8.37	8.54	9.01
Other[2]	1.65	0.35	0.35	0.35	0.30	0.30	0.30	0.33	0.33	0.33
Total	**73.26**	**77.79**	**77.60**	**77.47**	**80.90**	**80.36**	**80.30**	**87.61**	**87.09**	**85.11**
Imports										
Crude Oil[3]	18.96	21.42	21.43	21.40	22.49	22.42	22.46	25.91	25.86	25.89
Petroleum Products[4]	4.14	6.11	6.10	6.00	8.52	8.37	8.28	10.70	10.59	10.45
Natural Gas	3.63	5.14	5.15	5.15	5.55	5.65	5.64	6.55	6.64	6.74
Other Imports[5]	0.64	1.11	1.11	1.11	0.96	0.96	0.96	0.96	0.96	0.96
Total	**27.37**	**33.78**	**33.79**	**33.66**	**37.52**	**37.40**	**37.34**	**44.11**	**44.05**	**44.03**
Exports										
Petroleum[6]	1.98	1.73	1.73	1.73	1.73	1.71	1.70	1.82	1.87	1.89
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.43	0.43	0.63	0.63	0.63
Coal	1.48	1.51	1.51	1.52	1.45	1.53	1.53	1.41	1.38	1.41
Total	**3.62**	**3.56**	**3.57**	**3.58**	**3.61**	**3.67**	**3.66**	**3.87**	**3.89**	**3.93**
Discrepancy[7]	**0.67**	**0.44**	**0.42**	**0.45**	**0.06**	**0.01**	**-0.00**	**0.18**	**0.14**	**0.09**
Consumption										
Petroleum Products[8]	37.92	41.21	41.24	41.08	44.30	44.30	44.20	50.36	50.35	50.26
Natural Gas	22.32	26.38	26.50	26.48	28.94	29.77	29.95	35.88	36.51	37.16
Coal	21.40	24.37	23.96	23.78	25.57	23.90	23.44	26.30	24.92	21.70
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.74
Renewable Energy[1]	6.53	7.10	7.19	7.25	7.87	7.97	8.23	8.38	8.55	9.02
Other[9]	0.35	0.61	0.61	0.61	0.38	0.38	0.38	0.25	0.25	0.25
Total	**96.33**	**107.5**	**107.4**	**107.1**	**114.7**	**114.0**	**113.9**	**127.6**	**127.1**	**125.1**
Net Imports - Petroleum	**21.12**	**25.80**	**25.79**	**25.67**	**29.28**	**29.08**	**29.05**	**34.78**	**34.58**	**34.46**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.22	20.83	20.83	20.83	21.37	21.37	21.37	22.41	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.99	3.03	3.01	2.82	2.95	2.94	3.10	3.35	3.43
Coal Minemouth Price (dollars per ton)	17.13	15.22	15.78	15.21	14.19	14.69	14.62	12.93	12.87	12.35
Average Electric Price (cents per Kwh)	6.7	6.4	6.4	6.4	6.1	6.2	6.2	6.1	6.3	7.0

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.80	0.80	0.76	0.76	0.76
Kerosene	0.10	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.46	0.46	0.46	0.43	0.43	0.43	0.41	0.41	0.42
Petroleum Subtotal	1.42	1.41	1.41	1.41	1.30	1.31	1.30	1.23	1.24	1.25
Natural Gas	4.88	5.55	5.55	5.55	5.54	5.52	5.52	6.08	6.03	6.02
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Electricity	3.91	4.56	4.56	4.55	4.91	4.88	4.88	5.69	5.63	5.50
Delivered Energy	**10.66**	**11.99**	**11.98**	**11.97**	**12.22**	**12.18**	**12.17**	**13.48**	**13.38**	**13.25**
Electricity Related Losses	8.44	9.66	9.53	9.51	10.00	9.71	9.74	10.65	10.47	9.88
Total	**19.10**	**21.65**	**21.52**	**21.49**	**22.22**	**21.89**	**21.91**	**24.14**	**23.85**	**23.13**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.37	0.37	0.37
Residual Fuel	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.60	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62
Natural Gas	3.14	3.99	3.99	3.99	4.19	4.16	4.16	4.47	4.42	4.44
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.66	4.40	4.39	4.39	4.92	4.90	4.91	5.64	5.61	5.49
Delivered Energy	**7.55**	**9.15**	**9.13**	**9.14**	**9.88**	**9.84**	**9.85**	**10.88**	**10.80**	**10.70**
Electricity Related Losses	7.91	9.33	9.19	9.19	10.02	9.76	9.81	10.56	10.42	9.86
Total	**15.46**	**18.48**	**18.32**	**18.33**	**19.90**	**19.59**	**19.66**	**21.44**	**21.22**	**20.56**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.22	1.21	1.30	1.30	1.30	1.49	1.49	1.49
Liquefied Petroleum Gas	2.32	2.44	2.46	2.44	2.51	2.51	2.52	2.85	2.85	2.85
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.27	0.28	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.25	0.25	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.41	4.45	4.42	4.68	4.71	4.68	5.00	5.02	5.03
Petroleum Subtotal	9.45	9.81	9.88	9.82	10.51	10.55	10.53	11.58	11.63	11.63
Natural Gas[6]	9.80	10.42	10.43	10.40	11.27	11.31	11.27	12.71	12.73	12.81
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.80	1.80	1.80	1.82	1.79	1.77	1.86	1.80	1.76
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.58	2.58	2.55	2.53	2.59	2.52	2.48
Renewable Energy[7]	2.15	2.40	2.42	2.40	2.63	2.64	2.63	3.07	3.08	3.08
Electricity	3.61	3.88	3.89	3.87	4.16	4.17	4.15	4.76	4.75	4.65
Delivered Energy	**27.56**	**29.10**	**29.20**	**29.08**	**31.14**	**31.22**	**31.11**	**34.72**	**34.70**	**34.65**
Electricity Related Losses	7.80	8.21	8.15	8.09	8.47	8.29	8.30	8.91	8.83	8.35
Total	**35.36**	**37.31**	**37.35**	**37.17**	**39.61**	**39.51**	**39.41**	**43.63**	**43.53**	**43.00**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Transportation										
Distillate Fuel	5.13	6.25	6.27	6.24	6.98	6.98	6.96	8.21	8.21	8.17
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Motor Gasoline[2]	15.92	17.64	17.68	17.64	18.94	18.97	18.95	21.25	21.27	21.23
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86
Liquefied Petroleum Gas	0.02	0.03	0.03	0.03	0.04	0.05	0.04	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.30	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	28.95	29.03	28.94	31.62	31.67	31.60	36.70	36.72	36.65
Pipeline Fuel Natural Gas	0.66	0.82	0.83	0.83	0.90	0.93	0.93	1.10	1.12	1.13
Compressed Natural Gas	0.02	0.05	0.06	0.05	0.09	0.09	0.09	0.16	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.09	0.09	0.09	0.12	0.12	0.12	0.17	0.17	0.17
Delivered Energy	**26.28**	**29.94**	**30.03**	**29.93**	**32.77**	**32.85**	**32.78**	**38.16**	**38.21**	**38.15**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.23	0.24	0.31	0.31	0.30
Total	**26.41**	**30.12**	**30.21**	**30.12**	**33.01**	**33.08**	**33.02**	**38.47**	**38.51**	**38.44**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.70	8.73	8.70	9.46	9.47	9.44	10.82	10.83	10.79
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.04	3.02	3.07	3.08	3.08	3.41	3.42	3.43
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.24	19.22	21.56	21.58	21.54
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.23	1.24	1.24
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.97	5.33	5.35	5.36
Petroleum Subtotal	37.01	40.77	40.92	40.77	44.05	44.14	44.05	50.13	50.21	50.14
Natural Gas[6]	18.50	20.84	20.85	20.82	21.99	22.02	21.97	24.52	24.44	24.55
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.94	1.91	1.90	1.99	1.92	1.89
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.70	2.71	2.70	2.70	2.67	2.66	2.71	2.64	2.61
Renewable Energy[13]	2.65	2.93	2.94	2.93	3.17	3.18	3.17	3.64	3.64	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.24	12.93	12.93	12.90	14.10	14.06	14.06	16.25	16.16	15.80
Delivered Energy	**72.05**	**80.17**	**80.35**	**80.12**	**86.01**	**86.08**	**85.91**	**97.25**	**97.09**	**96.74**
Electricity Related Losses	24.28	27.39	27.05	26.98	28.73	27.99	28.08	30.43	30.02	28.38
Total	**96.33**	**107.5**	**107.4**	**107.1**	**114.7**	**114.0**	**113.9**	**127.6**	**127.1**	**125.1**
Electric Generators[14]										
Distillate Fuel	0.05	0.06	0.05	0.05	0.06	0.04	0.04	0.06	0.04	0.02
Residual Fuel	0.86	0.37	0.27	0.26	0.20	0.12	0.12	0.17	0.10	0.09
Petroleum Subtotal	0.91	0.43	0.32	0.31	0.25	0.16	0.16	0.23	0.14	0.11
Natural Gas	3.83	5.54	5.65	5.66	6.96	7.76	7.98	11.36	12.07	12.61
Steam Coal	18.75	21.67	21.25	21.08	22.87	21.23	20.78	23.59	22.28	19.09
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.74
Renewable Energy[15]	3.88	4.17	4.25	4.32	4.70	4.80	5.06	4.75	4.91	5.39
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**35.52**	**40.32**	**39.98**	**39.88**	**42.83**	**42.06**	**42.14**	**46.68**	**46.18**	**44.19**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Total Energy Consumption										
Distillate Fuel	7.53	8.77	8.78	8.75	9.51	9.50	9.48	10.88	10.87	10.82
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.04	3.02	3.07	3.08	3.08	3.41	3.42	3.43
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.24	19.22	21.56	21.58	21.54
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.92	1.48	1.38	1.36	1.39	1.32	1.32	1.41	1.34	1.33
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.97	5.33	5.35	5.36
Petroleum Subtotal	37.92	41.21	41.24	41.08	44.30	44.30	44.20	50.36	50.35	50.26
Natural Gas	22.32	26.38	26.50	26.48	28.94	29.77	29.95	35.88	36.51	37.16
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.59	23.59	23.17	22.99	24.81	23.14	22.68	25.58	24.20	20.98
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	21.40	24.37	23.96	23.78	25.57	23.90	23.44	26.30	24.92	21.70
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.74	7.79	6.51	6.54	6.74
Renewable Energy[17]	6.53	7.10	7.19	7.25	7.87	7.97	8.23	8.38	8.55	9.02
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**96.33**	**107.56**	**107.40**	**107.11**	**114.74**	**114.07**	**113.99**	**127.68**	**127.12**	**125.13**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.17	80.35	80.12	86.01	86.08	85.91	97.25	97.09	96.74
Total Energy Use	96.33	107.56	107.40	107.11	114.74	114.07	113.99	127.68	127.12	125.13
Population (millions)	273.13	288.02	288.02	288.02	300.17	300.17	300.17	325.24	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10908	10960	10905	12634	12667	12634	16509	16515	16512
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1701.4	1691.8	1684.9	1820.6	1789.0	1777.9	2043.8	2016.8	1942.4

[1]Includes wood used for residential heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass.
[4]Fuel consumption includes consumption for cogeneration, which provides electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1999 electric utility fuel consumption: Energy Information Administration, (EIA) *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2005 Reference	2005 65 Percent	2005 65 Percent with CO_2 Cap	2010 Reference	2010 65 Percent	2010 65 Percent with CO_2 Cap	2020 Reference	2020 65 Percent	2020 65 Percent with CO_2 Cap
Residential	**13.18**	**13.33**	**13.42**	**13.41**	**13.41**	**13.70**	**13.64**	**13.62**	**14.04**	**14.79**
Primary Energy[1]	6.71	7.50	7.54	7.52	7.17	7.27	7.27	7.01	7.21	7.25
Petroleum Products[2]	7.55	9.17	9.17	9.17	9.37	9.37	9.37	9.47	9.45	9.38
Distillate Fuel	6.27	7.37	7.38	7.37	7.57	7.57	7.56	7.76	7.75	7.74
Liquefied Petroleum Gas	10.36	12.61	12.61	12.61	12.82	12.81	12.82	12.71	12.66	12.45
Natural Gas	6.52	7.13	7.18	7.16	6.70	6.83	6.82	6.56	6.79	6.85
Electricity	23.69	22.29	22.46	22.46	22.19	22.77	22.63	22.16	22.92	24.81
Commercial	**13.28**	**12.71**	**12.81**	**12.80**	**12.23**	**12.42**	**12.36**	**12.55**	**12.97**	**14.08**
Primary Energy[1]	5.22	5.58	5.61	5.59	5.65	5.75	5.75	5.69	5.88	5.93
Petroleum Products[2]	4.99	6.08	6.08	6.08	6.27	6.26	6.26	6.37	6.35	6.31
Distillate Fuel	4.37	5.17	5.17	5.17	5.35	5.35	5.34	5.51	5.50	5.49
Residual Fuel	2.63	3.64	3.63	3.63	3.70	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.57	5.61	5.59	5.63	5.75	5.75	5.67	5.90	5.96
Electricity	21.64	20.28	20.45	20.45	18.76	19.01	18.89	18.83	19.43	21.71
Industrial[4]	**5.29**	**5.75**	**5.78**	**5.77**	**5.62**	**5.71**	**5.69**	**5.82**	**6.00**	**6.23**
Primary Energy	3.91	4.46	4.49	4.48	4.45	4.50	4.50	4.61	4.72	4.69
Petroleum Products[2]	5.54	5.97	5.97	5.97	6.07	6.07	6.07	6.12	6.09	5.96
Distillate Fuel	4.65	5.33	5.33	5.33	5.53	5.54	5.52	5.71	5.70	5.69
Liquefied Petroleum Gas	8.50	7.75	7.76	7.76	7.77	7.75	7.79	7.68	7.64	7.42
Residual Fuel	2.78	3.37	3.36	3.36	3.43	3.42	3.42	3.58	3.58	3.57
Natural Gas[5]	2.79	3.66	3.71	3.69	3.46	3.58	3.57	3.73	3.98	4.04
Metallurgical Coal	1.66	1.58	1.59	1.58	1.54	1.55	1.54	1.44	1.43	1.44
Steam Coal	1.43	1.35	1.36	1.34	1.30	1.30	1.29	1.21	1.18	1.15
Electricity	13.12	12.81	12.89	12.90	12.04	12.26	12.16	12.07	12.67	14.42
Transportation	**8.30**	**9.33**	**9.34**	**9.34**	**9.63**	**9.66**	**9.65**	**9.20**	**9.20**	**9.22**
Primary Energy	8.29	9.32	9.32	9.32	9.61	9.65	9.63	9.18	9.18	9.20
Petroleum Products[2]	8.28	9.32	9.32	9.32	9.61	9.64	9.63	9.18	9.18	9.19
Distillate Fuel[6]	8.22	8.89	8.90	8.89	8.94	8.95	8.94	8.83	8.82	8.83
Jet Fuel[7]	4.70	5.22	5.23	5.23	5.49	5.49	5.49	5.72	5.72	5.71
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.26	11.24	10.60	10.60	10.63
Residual Fuel	2.46	3.11	3.10	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.08	14.07	14.00	13.98	14.02	13.64	13.59	13.41
Natural Gas[10]	7.02	7.30	7.34	7.33	7.17	7.30	7.30	7.30	7.52	7.59
Ethanol (E85)[11]	14.42	19.20	19.20	19.21	19.13	19.16	19.15	19.34	19.37	19.38
Methanol (M85)[12]	10.38	13.13	13.18	13.15	13.80	13.82	13.81	14.35	14.36	14.37
Electricity	15.64	14.61	14.64	14.64	13.73	14.16	14.07	13.18	13.67	14.51
Average End-Use Energy	**8.52**	**9.16**	**9.19**	**9.19**	**9.16**	**9.26**	**9.24**	**9.13**	**9.30**	**9.61**
Primary Energy	6.31	7.16	7.18	7.17	7.30	7.35	7.35	7.20	7.27	7.27
Electricity	19.58	18.71	18.84	18.86	17.93	18.27	18.16	17.96	18.60	20.57
Electric Generators[13]										
Fossil Fuel Average	1.48	1.63	1.66	1.66	1.59	1.71	1.73	1.85	2.00	2.19
Petroleum Products	2.48	3.60	3.66	3.68	3.96	4.17	4.18	4.20	4.48	4.51
Distillate Fuel	4.07	4.65	4.68	4.67	4.85	4.88	4.86	5.05	5.06	5.12
Residual Fuel	2.39	3.43	3.48	3.49	3.70	3.96	3.96	3.92	4.28	4.35
Natural Gas	2.57	3.42	3.52	3.51	3.23	3.46	3.45	3.62	3.90	4.04
Steam Coal	1.21	1.13	1.13	1.13	1.06	1.05	1.05	0.98	0.96	0.95

Table C3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Average Price to All Users[14]										
Petroleum Products[2]	7.46	8.48	8.49	8.50	8.75	8.79	8.78	8.49	8.49	8.47
Distillate Fuel	7.25	8.06	8.07	8.06	8.20	8.20	8.20	8.20	8.19	8.20
Jet Fuel	4.70	5.22	5.23	5.23	5.49	5.49	5.49	5.72	5.72	5.71
Liquefied Petroleum Gas	8.84	8.65	8.65	8.66	8.66	8.65	8.67	8.48	8.44	8.23
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.26	11.24	10.60	10.60	10.63
Residual Fuel	2.47	3.25	3.24	3.24	3.33	3.33	3.33	3.49	3.48	3.48
Natural Gas	4.04	4.73	4.78	4.76	4.43	4.55	4.53	4.50	4.73	4.80
Coal	1.23	1.15	1.15	1.15	1.08	1.08	1.07	0.99	0.97	0.97
Ethanol (E85)[11]	14.42	19.20	19.20	19.21	19.13	19.16	19.15	19.34	19.37	19.38
Methanol (M85)[12]	10.38	13.13	13.18	13.15	13.80	13.82	13.81	14.35	14.36	14.37
Electricity	19.58	18.71	18.84	18.86	17.93	18.27	18.16	17.96	18.60	20.57
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	135.11	154.2	155.1	154.8	158.2	161.0	160.2	177.6	181.8	189.5
Commercial	99.11	115.3	115.9	115.9	119.8	121.1	120.6	135.5	139.0	149.5
Industrial	112.11	126.4	127.6	126.7	131.8	134.0	133.1	152.0	156.8	163.1
Transportation	212.64	271.3	272.1	271.3	306.1	307.7	306.6	340.1	340.4	340.5
Total Non-Renewable Expenditures	558.97	667.3	670.8	668.9	716.0	723.9	720.6	805.4	818.2	842.7
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.62	0.63	0.63	0.85	0.85	0.85
Total Expenditures	**559.11**	**667.7**	**671.2**	**669.3**	**716.6**	**724.5**	**721.2**	**806.2**	**819.1**	**843.6**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Generation by Fuel Type										
Electric Generators[1]										
Coal	1830	2105	2062	2049	2238	2064	2014	2302	2135	1842
Petroleum	85	42	32	31	25	16	16	23	14	12
Natural Gas[2]	370	582	629	632	826	989	1026	1488	1626	1767
Nuclear Power	730	740	740	740	720	725	729	610	613	631
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	372	378	381	396	401	409	399	409	438
Total	**3369**	**3839**	**3840**	**3831**	**4204**	**4194**	**4194**	**4821**	**4796**	**4690**
Non-Utility Generation for Own Use	16	17	17	17	17	16	16	16	16	23
Distributed Generation	0	0	0	0	1	1	1	5	4	4
Cogenerators[4]										
Coal	47	53	52	52	51	50	49	52	47	42
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	236	237	237	259	259	258	317	320	350
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	9
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	6	6	6
Total	**303**	**344**	**344**	**345**	**372**	**370**	**368**	**440**	**438**	**464**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	170	170	179	177	175	208	203	207
Generation for Own Use	156	177	179	179	197	198	198	237	240	262
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1337	1335	1333	1438	1429	1429	1668	1651	1613
Commercial	1073	1291	1287	1288	1442	1437	1439	1653	1643	1608
Industrial	1058	1137	1141	1134	1219	1221	1217	1394	1392	1362
Transportation	17	26	26	26	34	35	34	49	49	49
Total	**3294**	**3790**	**3789**	**3781**	**4133**	**4122**	**4120**	**4763**	**4736**	**4631**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.1	7.6	7.7	7.7	7.6	7.8	7.7	7.6	7.8	8.5
Commercial	7.4	6.9	7.0	7.0	6.4	6.5	6.4	6.4	6.6	7.4
Industrial	4.5	4.4	4.4	4.4	4.1	4.2	4.1	4.1	4.3	4.9
Transportation	5.3	5.0	5.0	5.0	4.7	4.8	4.8	4.5	4.7	5.0
All Sectors Average	**6.7**	**6.4**	**6.4**	**6.4**	**6.1**	**6.2**	**6.2**	**6.1**	**6.3**	**7.0**
Prices by Service Category[9] **(1999 cents per kwh)**										
Generation	4.1	3.8	3.9	3.9	3.4	3.5	3.5	3.5	3.7	4.4
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.49	10.39	8.37	8.37	9.70	6.07	6.07	8.95	3.13	3.13
Nitrogen Oxide	5.43	4.30	4.32	4.32	4.34	2.85	2.86	4.48	2.24	1.99

[1] Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2] Includes electricity generation by fuel cells.
[3] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4] Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5] Other gaseous fuels include refinery and still gas.
[6] Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8] In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9] Prices represent average revenue per kilowatthour.

Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.4	302.8	317.8	304.8	295.8	317.3	302.6	291.0
Other Fossil Steam[3]	137.4	124.9	120.4	119.5	117.4	104.8	104.3	114.9	104.3	103.7
Combined Cycle	21.0	52.4	77.4	77.4	107.3	149.8	157.1	199.0	229.4	238.3
Combustion Turbine/Diesel	86.8	126.4	125.1	126.9	149.8	140.1	141.5	197.4	192.1	176.3
Nuclear Power	97.4	97.5	97.5	97.5	93.7	94.8	95.3	76.3	76.3	78.8
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	88.8	94.7	94.9	95.3	97.9	98.3	99.4	99.4	99.9	101.0
Distributed Generation[5]	0.0	0.8	0.3	0.3	2.5	2.0	2.2	11.0	9.8	9.1
Total	**755.9**	**820.0**	**838.3**	**839.2**	**906.0**	**914.2**	**915.2**	**1035.**	**1034.**	**1018.**
Cumulative Planned Additions[6]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Combustion Turbine/Diesel	0.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	5.1	5.1	5.1	6.7	6.7	6.7	8.1	8.1	8.1
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**32.0**	**32.0**	**32.0**	**33.7**	**33.7**	**33.7**	**35.3**	**35.3**	**35.3**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	1.1	0.6	0.0	18.2	8.6	0.0	19.5	8.9	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	18.6	43.6	43.7	73.6	116.1	123.4	165.4	195.7	204.6
Combustion Turbine/Diesel	0.0	30.9	20.5	22.2	55.4	38.4	39.7	103.1	90.5	75.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	0.6	1.0	1.9	2.4	3.4	1.9	2.4	3.5
Distributed Generation[5]	0.0	0.8	0.3	0.3	2.5	2.0	2.2	11.0	9.8	9.1
Total	**0.0**	**51.7**	**65.6**	**67.1**	**151.5**	**167.4**	**168.8**	**300.8**	**307.4**	**292.4**
Cumulative Total Additions	**0.0**	**83.7**	**97.6**	**99.1**	**185.2**	**201.1**	**202.4**	**336.1**	**342.7**	**327.7**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.5	9.0	9.3	7.3	11.4	14.1
Other Fossil Steam[3]	0.0	12.7	17.3	18.1	20.2	32.8	33.4	22.7	33.4	33.9
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.1	0.1	0.2	0.1	0.1
Combustion Turbine/Diesel	0.0	5.5	3.4	3.3	6.6	6.3	6.2	6.7	6.4	6.7
Nuclear Power	0.0	0.0	0.0	0.0	3.7	2.6	2.2	21.2	21.2	18.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**20.6**	**23.2**	**23.9**	**36.4**	**51.0**	**51.3**	**58.1**	**72.6**	**73.8**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.9	7.8	8.6	7.5	7.0
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Natural Gas	34.6	39.7	40.0	40.0	43.1	43.3	43.2	51.2	51.8	55.7
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.1	1.1
Renewable Sources[4]	5.4	5.9	5.9	5.9	6.8	6.8	6.8	8.3	8.2	8.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.1**	**59.3**	**59.4**	**63.1**	**62.7**	**62.5**	**73.0**	**72.4**	**76.0**
Cumulative Additions[6]	**0.0**	**6.7**	**6.9**	**6.9**	**10.7**	**10.2**	**10.1**	**20.5**	**20.0**	**23.6**

Table C5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Other End-Use Generators[9]										
Renewable Sources	1.0	1.1	1.1	1.1	1.3	1.3	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[6]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31,1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	182.2	125.3	125.3	125.3	102.9	102.9	102.9	0.0	0.0	0.0
Gross Domestic Economy Trade	152.1	199.1	215.8	215.6	154.6	133.2	137.9	146.4	126.0	114.7
Gross Domestic Trade	**334.3**	**324.4**	**341.1**	**340.9**	**257.5**	**236.1**	**240.8**	**146.4**	**126.0**	**114.7**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.	5905.	5905.	4851.	4851.	4851.	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4204.3	6352.	6978.	6918.	4407.	4001.	4126.	4448.	4228.	4595.
Gross Domestic Sales (million 1999 dollars)	**12792.4**	**1225**	**1288**	**1282**	**9258.**	**8852.**	**8977.**	**4448.**	**4228.**	**4595.**
International Electricity Trade										
Firm Power Imports From Canada and	27.0	10.7	10.7	10.7	5.8	5.8	5.8	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	21.9	63.5	63.5	63.5	45.9	45.9	45.9	30.6	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**74.1**	**74.1**	**74.1**	**51.7**	**51.7**	**51.7**	**30.6**	**30.6**	**30.6**
Firm Power Exports To Canada and Mexico	9.2	9.7	9.7	9.7	8.7	8.7	8.7	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.0	7.0	7.0	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.7**	**16.7**	**16.7**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.

CO_2 = Carbon dioxide.

Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Production										
Dry Gas Production[1]	18.67	21.32	21.43	21.42	23.36	24.11	24.27	29.34	29.89	30.44
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.70**	**4.72**	**4.72**	**5.01**	**5.10**	**5.09**	**5.78**	**5.87**	**5.96**
Canada	3.29	4.49	4.50	4.50	4.72	4.81	4.80	5.39	5.47	5.56
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	-0.25	-0.25	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	0.54	0.54	0.79	0.80	0.80
Total Supply	**22.15**	**26.14**	**26.26**	**26.25**	**28.42**	**29.26**	**29.41**	**35.17**	**35.82**	**36.46**
Consumption by Sector										
Residential	4.75	5.40	5.40	5.40	5.39	5.38	5.37	5.92	5.87	5.86
Commercial	3.06	3.89	3.88	3.88	4.08	4.05	4.05	4.36	4.30	4.32
Industrial[3]	8.31	8.78	8.79	8.76	9.48	9.48	9.43	10.52	10.50	10.56
Electric Generators[4]	3.76	5.44	5.55	5.56	6.83	7.61	7.83	11.15	11.85	12.37
Lease and Plant Fuel[5]	1.23	1.36	1.37	1.37	1.50	1.53	1.54	1.86	1.89	1.92
Pipeline Fuel	0.64	0.80	0.81	0.81	0.88	0.91	0.91	1.07	1.09	1.10
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.77**	**25.73**	**25.85**	**25.83**	**28.24**	**29.05**	**29.22**	**35.03**	**35.65**	**36.28**
Discrepancy[7]	**0.38**	**0.41**	**0.41**	**0.41**	**0.19**	**0.21**	**0.19**	**0.15**	**0.17**	**0.17**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C8. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.99	3.03	3.01	2.82	2.95	2.94	3.10	3.35	3.43
Average Import Price	2.29	2.99	3.00	3.00	2.66	2.70	2.69	2.71	2.77	2.79
Average[2]	**2.11**	**2.99**	**3.03**	**3.01**	**2.79**	**2.90**	**2.90**	**3.03**	**3.25**	**3.31**
Delivered Prices										
Residential	6.69	7.33	7.37	7.35	6.88	7.01	7.01	6.74	6.98	7.04
Commercial	5.49	5.72	5.76	5.74	5.78	5.91	5.90	5.82	6.05	6.12
Industrial[3]	2.87	3.76	3.81	3.79	3.55	3.68	3.67	3.84	4.08	4.15
Electric Generators[4]	2.62	3.49	3.59	3.57	3.30	3.52	3.52	3.68	3.98	4.12
Transportation[5]	7.21	7.50	7.54	7.52	7.36	7.49	7.49	7.50	7.73	7.79
Average[6]	**4.14**	**4.85**	**4.90**	**4.88**	**4.55**	**4.67**	**4.65**	**4.61**	**4.85**	**4.93**
Transmission & Distribution Margins[7]										
Residential	4.58	4.34	4.35	4.34	4.09	4.11	4.11	3.71	3.72	3.73
Commercial	3.37	2.73	2.74	2.73	2.99	3.00	3.01	2.79	2.80	2.80
Industrial[3]	0.76	0.78	0.78	0.78	0.76	0.78	0.77	0.81	0.83	0.84
Electric Generators[4]	0.51	0.50	0.56	0.57	0.51	0.62	0.62	0.66	0.73	0.81
Transportation[5]	5.10	4.52	4.52	4.52	4.57	4.59	4.60	4.47	4.48	4.48
Average[6]	**2.03**	**1.87**	**1.88**	**1.88**	**1.76**	**1.76**	**1.76**	**1.59**	**1.60**	**1.62**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.45	23.48	23.46	22.07	22.09	22.08	21.95	21.86	21.83
Commercial	10.32	10.62	10.61	10.62	12.19	12.17	12.18	12.16	12.06	12.11
Industrial[3]	6.28	6.82	6.86	6.83	7.20	7.36	7.30	8.50	8.75	8.83
Electric Generators[4]	1.90	2.74	3.13	3.16	3.46	4.70	4.88	7.33	8.61	9.98
Transportation[5]	0.08	0.24	0.24	0.24	0.40	0.41	0.41	0.68	0.67	0.67
Total	**40.35**	**43.87**	**44.33**	**44.31**	**45.33**	**46.74**	**46.85**	**50.61**	**51.95**	**53.42**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1999 values, and projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C9. Oil and Gas Supply

Production and Supply	1999	Projections 2005 Reference	2005 65 Percent	2005 65 Percent with CO_2 Cap	2010 Reference	2010 65 Percent	2010 65 Percent with CO_2 Cap	2020 Reference	2020 65 Percent	2020 65 Percent with CO_2 Cap
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.48**	**21.17**	**21.11**	**20.80**	**20.80**	**20.81**	**21.50**	**21.50**	**21.48**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.69**	**5.69**	**5.68**	**5.30**	**5.33**	**5.30**	**5.22**	**5.26**	**5.24**
Lower 48 Onshore	3.27	2.80	2.81	2.80	2.50	2.51	2.50	2.71	2.75	2.74
Conventional	2.59	2.18	2.18	2.18	1.81	1.81	1.81	1.96	1.99	1.98
Enhanced Oil Recovery	0.68	0.62	0.62	0.62	0.69	0.70	0.69	0.74	0.76	0.76
Lower 48 Offshore	1.56	2.09	2.09	2.09	2.16	2.17	2.16	1.88	1.87	1.87
Alaska	1.05	0.79	0.79	0.79	0.65	0.65	0.65	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.76**	**15.76**	**15.76**	**14.43**	**14.57**	**14.49**	**14.01**	**14.16**	**14.08**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.99**	**3.03**	**3.01**	**2.82**	**2.95**	**2.94**	**3.10**	**3.35**	**3.43**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.32**	**21.43**	**21.42**	**23.36**	**24.11**	**24.27**	**29.34**	**29.89**	**30.44**
Lower 48 Onshore	12.83	14.37	14.47	14.45	16.42	17.08	17.25	21.10	21.58	22.00
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.32	1.32	1.38	1.40	1.39
Non-Associated	11.03	12.86	12.95	12.93	15.10	15.76	15.93	19.72	20.19	20.61
Conventional	6.64	7.62	7.69	7.66	7.79	8.13	8.24	11.05	11.12	11.44
Unconventional	4.39	5.24	5.26	5.28	7.30	7.63	7.68	8.66	9.07	9.16
Lower 48 Offshore	5.43	6.49	6.50	6.50	6.44	6.52	6.51	7.66	7.74	7.87
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.04	1.04
Non-Associated	4.50	5.42	5.44	5.44	5.35	5.43	5.43	6.63	6.70	6.84
Alaska	0.42	0.47	0.47	0.47	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**169.38**	**168.96**	**169.10**	**184.15**	**186.89**	**186.42**	**199.35**	**200.83**	**197.65**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.93**	**29.02**	**29.18**	**29.06**	**29.30**	**30.29**	**30.34**	**38.07**	**40.97**	**41.02**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC. June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Production[1]										
Appalachia	434	432	438	421	425	408	406	396	367	330
Interior	182	185	188	175	183	167	161	164	157	117
West	486	612	570	600	681	617	600	775	725	644
East of the Mississippi	558	569	583	554	564	539	533	526	505	435
West of the Mississippi	544	659	613	642	725	652	634	810	744	656
Total	**1102**	**1228**	**1196**	**1196**	**1289**	**1191**	**1167**	**1336**	**1249**	**1091**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	61	61	56	55	56
Total	**-49**	**-44**	**-44**	**-45**	**-40**	**-43**	**-43**	**-36**	**-36**	**-36**
Total Supply[2]	**1053**	**1184**	**1152**	**1151**	**1249**	**1148**	**1123**	**1300**	**1213**	**1054**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	82	81	85	82	81
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	920	1073	1040	1040	1139	1042	1019	1190	1109	954
Total	**1031**	**1185**	**1153**	**1152**	**1250**	**1151**	**1128**	**1299**	**1215**	**1058**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-1**	**-3**	**-4**	**1**	**-2**	**-4**
Average Minemouth Price										
(1999 dollars per short ton)	17.13	15.22	15.78	15.21	14.19	14.69	14.62	12.93	12.87	12.35
(1999 dollars per million Btu)	0.82	0.74	0.75	0.73	0.69	0.70	0.70	0.64	0.63	0.60
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.37	29.65	29.75	29.38	28.56	28.42	28.18	26.49	25.86	25.12
Coke Plants	44.38	42.40	42.49	42.34	41.25	41.55	41.23	38.50	38.42	38.62
Electric Generators										
(1999 dollars per short ton)	24.69	22.92	23.11	22.91	21.26	21.49	21.50	19.34	19.21	18.99
(1999 dollars per million Btu)	1.21	1.13	1.13	1.13	1.06	1.05	1.05	0.98	0.96	0.95
Average	**25.74**	**23.80**	**24.01**	**23.80**	**22.11**	**22.38**	**22.38**	**20.09**	**19.96**	**19.81**
Exports[7]	37.50	36.41	36.35	36.12	35.57	35.41	35.12	33.07	32.50	32.53

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000..
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data based on Energy Information Administration (EIA), *Quarterly Coal Report* , DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.26	79.26	79.38	79.38	79.38	79.38	79.38	79.38
Geothermal[2]	2.87	3.36	3.46	3.72	4.81	5.07	6.15	4.83	5.12	6.15
Municipal Solid Waste[3]	2.61	2.96	3.11	3.20	3.42	3.65	3.66	3.93	4.16	4.17
Wood and Other Biomass[4]	1.57	1.75	1.75	1.75	2.12	2.12	2.12	2.45	2.45	2.48
Solar Thermal	0.33	0.35	0.35	0.35	0.40	0.40	0.40	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.66	6.92	6.92	6.92	7.52	7.52	7.52	7.74	7.77	7.78
Total	**88.83**	**94.68**	**94.93**	**95.28**	**97.85**	**98.35**	**99.43**	**99.35**	**99.89**	**100.9**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.2	301.2	301.2	301.1	301.1	301.1	300.0	300.0	300.0
Geothermal[2]	13.21	17.71	18.52	20.70	29.92	32.10	41.05	30.13	32.51	41.10
Municipal Solid Waste[3]	18.12	20.68	21.85	22.59	23.88	25.68	25.70	27.76	29.56	29.64
Wood and Other Biomass[4]	8.76	14.92	18.60	18.59	21.22	22.18	21.30	19.29	25.38	45.74
Dedicated Plants	7.73	9.17	9.17	9.16	11.36	11.37	11.37	13.82	13.84	14.09
Cofiring	1.03	5.75	9.43	9.43	9.86	10.80	9.93	5.47	11.54	31.65
Solar Thermal	0.89	0.96	0.96	0.96	1.11	1.11	1.11	1.37	1.37	1.37
Solar Photovoltaic	0.03	0.20	0.20	0.20	0.51	0.51	0.51	1.36	1.36	1.36
Wind	4.61	16.30	16.30	16.30	18.16	18.16	18.16	18.77	18.85	18.90
Total	**355.16**	**371.9**	**377.6**	**380.5**	**395.9**	**400.8**	**408.9**	**398.7**	**409.0**	**438.1**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.19	5.17	5.19	6.09	6.06	6.10	7.59	7.54	7.59
Total	**5.35**	**5.89**	**5.87**	**5.89**	**6.79**	**6.76**	**6.80**	**8.29**	**8.24**	**8.29**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04
Biomass	27.08	30.04	29.92	30.03	35.20	35.01	35.20	43.82	43.52	43.83
Total	**31.12**	**34.08**	**33.97**	**34.08**	**39.24**	**39.05**	**39.25**	**47.87**	**47.57**	**47.88**
Other End-Use Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.10	0.10	0.10	0.35	0.35	0.35	0.35	0.35	0.35
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.44	4.44	4.44	4.43	4.43	4.43	4.41	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.20	0.20	0.20	0.75	0.75	0.75	0.75	0.75	0.75
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.17**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.43**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.40**	**2.42**	**2.40**	**2.63**	**2.64**	**2.63**	**3.07**	**3.08**	**3.08**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.22	2.23	2.22	2.44	2.45	2.44	2.89	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.21	0.21	0.21
Electric Generators[5]	**3.88**	**4.17**	**4.25**	**4.32**	**4.70**	**4.80**	**5.06**	**4.75**	**4.91**	**5.39**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.10	3.10	3.10	3.08	3.08	3.08
Geothermal	0.28	0.42	0.45	0.52	0.82	0.88	1.16	0.82	0.90	1.16
Municipal Solid Waste[6]	0.25	0.28	0.30	0.31	0.32	0.35	0.35	0.38	0.40	0.40
Biomass	0.11	0.18	0.22	0.22	0.25	0.26	0.25	0.24	0.31	0.52
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.13	0.14	0.17	0.17	0.16
Cofiring	0.01	0.07	0.11	0.11	0.12	0.13	0.12	0.07	0.14	0.36
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.17	0.17	0.17	0.19	0.19	0.19	0.19	0.19	0.19
Total Marketed Renewable Energy	**6.64**	**7.27**	**7.36**	**7.43**	**8.05**	**8.15**	**8.41**	**8.58**	**8.75**	**9.22**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol										
From Corn	0.12	0.19	0.19	0.19	0.19	0.19	0.19	0.17	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility," and EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Residential										
Petroleum	26.0	26.6	26.6	26.6	24.6	24.6	24.6	23.3	23.4	23.5
Natural Gas	69.5	79.9	79.9	79.9	79.8	79.5	79.4	87.5	86.8	86.7
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	226.8	222.4	221.1	240.3	228.1	225.2	270.7	260.6	234.5
Total	**290.1**	**334.5**	**330.1**	**328.8**	**346.0**	**333.6**	**330.6**	**382.7**	**372.1**	**345.9**
Commercial										
Petroleum	13.7	11.9	11.9	11.9	12.1	12.1	12.1	12.0	12.1	12.1
Natural Gas	45.4	57.5	57.4	57.4	60.3	59.9	59.9	64.4	63.6	63.9
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	219.0	214.3	213.5	241.0	229.2	226.9	268.3	259.4	233.9
Total	**242.1**	**290.1**	**285.3**	**284.6**	**315.1**	**303.1**	**300.7**	**346.6**	**337.0**	**311.8**
Industrial[1]										
Petroleum	104.2	98.8	99.5	98.9	104.6	104.9	104.8	113.0	113.5	113.7
Natural Gas[2]	141.6	147.7	147.9	147.5	159.5	160.4	159.6	180.1	180.5	181.8
Coal	55.9	65.6	65.7	65.5	65.4	64.7	64.2	65.6	63.9	63.0
Electricity	178.8	192.9	190.0	188.0	203.7	194.9	191.9	226.3	219.7	198.0
Total	**480.4**	**505.0**	**503.1**	**500.0**	**533.2**	**524.9**	**520.5**	**585.0**	**577.7**	**556.5**
Transportation										
Petroleum[3]	485.8	554.7	556.2	554.5	606.2	607.1	605.8	703.5	703.9	702.6
Natural Gas[4]	9.5	12.6	12.8	12.7	14.3	14.7	14.7	18.0	18.3	18.5
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.3	4.3	5.8	5.5	5.4	7.9	7.7	7.1
Total[3]	**498.2**	**571.8**	**573.3**	**571.6**	**626.3**	**627.4**	**626.1**	**729.5**	**730.0**	**728.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	692.0	694.2	691.8	747.4	748.7	747.3	851.8	853.0	851.8
Natural Gas	266.0	297.8	297.9	297.6	313.9	314.6	313.7	350.0	349.2	350.8
Coal	58.8	68.5	68.6	68.5	68.6	67.8	67.4	68.8	67.1	66.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	643.1	631.0	626.9	690.7	657.7	649.4	773.1	747.4	673.5
Total[3]	**1510.8**	**1701**	**1691**	**1684**	**1820**	**1789**	**1777**	**2043**	**2016**	**1942**
Electric Generators[6]										
Petroleum	20.0	9.1	6.8	6.5	5.3	3.2	3.3	4.8	2.8	2.4
Natural Gas	45.8	79.8	81.4	81.5	100.2	111.7	114.9	163.6	173.8	181.6
Coal	490.5	554.2	542.8	538.8	585.3	542.8	531.3	604.7	570.8	489.5
Total	**556.3**	**643.1**	**631.0**	**626.9**	**690.7**	**657.7**	**649.4**	**773.1**	**747.4**	**673.5**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	701.1	701.0	698.4	752.6	751.9	750.6	856.5	855.8	854.2
Natural Gas	311.8	377.5	379.3	379.1	414.0	426.3	428.5	513.6	523.1	532.4
Coal	549.3	622.7	611.4	607.3	653.8	610.6	598.7	673.5	637.8	555.7
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1701**	**1691**	**1684**	**1820**	**1789**	**1777**	**2043**	**2016**	**1942**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.8**	**6.1**	**6.0**	**5.9**	**6.3**	**6.2**	**6.0**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99), (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Table C14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap	Reference	65 Percent	65 Percent with CO_2 Cap
Emissions										
Nitrogen Oxides (million tons)	5.43	4.30	4.32	4.32	4.34	2.85	2.86	4.48	2.24	1.99
Sulfur Dioxide (million tons)	13.49	10.39	8.37	8.37	9.70	6.07	6.07	8.95	3.13	3.13
Mercury (tons)	43.35	45.02	36.30	36.30	45.53	20.60	20.60	45.23	15.10	15.10
Carbon Dioxide (million metric tons carbon equivalent)	556.3	643.1	631.0	626.9	690.7	657.7	649.4	773.1	747.4	673.5
Allowance Prices										
Nitrogen Oxides (1999 dollars per ton)										
Summer Seasonal	0	4370	0	0	4404	0	0	5087	0	0
National Annual	0	0	1123	1077	0	1491	1475	0	1457	931
Sulfur Dioxide (1999 dollars per ton)	0	184	149	219	180	415	409	200	1390	2009
Mercury (million 1999 dollars per ton)	0	0	57	55	0	40	38	0	82	53
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	37
Retrofits (gigawatts, cumulative from 1999)										
Scrubber[1]	0.0	8.9	33.3	22.4	8.9	42.9	44.4	17.5	127.3	85.9
Combustion	0.0	40.4	34.2	35.5	42.5	50.0	54.4	46.6	57.9	57.3
SCR Post-combustion	0.0	90.8	4.4	3.3	90.9	93.8	92.0	91.1	156.3	140.9
SNCR Post-combustion	0.0	28.5	0.8	0.6	28.5	15.2	14.9	46.0	55.5	58.2
Mercury Spray Cooler	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	3.8	5.3
Mercury Fabric Filter	0.0	0.0	0.0	0.0	0.0	60.5	60.0	0.0	60.5	60.0
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	473	582	547	580	633	593	579	714	633	606
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433	456	449	437	465	422	412	442	442	352
High Sulfur (> 1.67 lbs. S/mmBtu)	196	190	199	179	191	177	176	180	174	133

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
CO_2 = Carbon dioxide.
lbs. S/mmBtu = Pounds sulfur per million British thermal units.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC6512.D081701B, REWC6512.D082001A.

Appendix D

Tables for the 75-Percent Reduction Case

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Production										
Crude Oil and Lease Condensate	12.45	12.04	12.01	12.02	11.23	11.26	11.22	11.06	11.16	11.15
Natural Gas Plant Liquids	2.62	3.11	3.15	3.14	3.36	3.44	3.47	4.14	4.23	4.32
Dry Natural Gas	19.16	21.88	22.15	22.11	23.97	24.57	24.77	30.10	30.78	31.43
Coal	23.06	25.43	24.62	24.63	26.49	24.93	24.51	27.10	25.12	21.83
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.79	7.79	6.51	6.54	6.74
Renewable Energy[1]	6.52	7.09	7.24	7.27	7.86	8.00	8.23	8.37	8.59	9.07
Other[2]	1.65	0.35	0.35	0.35	0.30	0.30	0.30	0.33	0.33	0.33
Total	**73.26**	**77.79**	**77.42**	**77.43**	**80.90**	**80.29**	**80.28**	**87.61**	**86.76**	**84.86**
Imports										
Crude Oil[3]	18.96	21.42	21.43	21.41	22.49	22.43	22.48	25.91	25.81	25.85
Petroleum Products[4]	4.14	6.11	6.09	5.97	8.52	8.42	8.33	10.70	10.60	10.43
Natural Gas	3.63	5.14	5.16	5.15	5.55	5.70	5.68	6.55	6.75	6.78
Other Imports[5]	0.64	1.11	1.11	1.11	0.96	0.96	0.96	0.96	0.96	0.96
Total	**27.37**	**33.78**	**33.79**	**33.64**	**37.52**	**37.51**	**37.45**	**44.11**	**44.12**	**44.02**
Exports										
Petroleum[6]	1.98	1.73	1.73	1.74	1.73	1.72	1.71	1.82	1.88	1.85
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.43	0.43	0.63	0.63	0.63
Coal	1.48	1.51	1.52	1.52	1.45	1.45	1.46	1.41	1.38	1.41
Total	**3.62**	**3.56**	**3.58**	**3.59**	**3.61**	**3.61**	**3.61**	**3.87**	**3.90**	**3.90**
Discrepancy[7]	**0.67**	**0.44**	**0.41**	**0.45**	**0.06**	**0.12**	**0.09**	**0.18**	**0.17**	**0.01**
Consumption										
Petroleum Products[8]	37.92	41.21	41.22	41.06	44.30	44.29	44.21	50.36	50.33	50.29
Natural Gas	22.32	26.38	26.67	26.62	28.94	29.66	29.85	35.88	36.74	37.40
Coal	21.40	24.37	23.57	23.56	25.57	23.94	23.57	26.30	24.35	21.22
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.79	7.79	6.51	6.54	6.74
Renewable Energy[1]	6.53	7.10	7.25	7.27	7.87	8.01	8.24	8.38	8.60	9.07
Other[9]	0.35	0.61	0.61	0.61	0.38	0.38	0.38	0.25	0.25	0.25
Total	**96.33**	**107.56**	**107.23**	**107.03**	**114.74**	**114.07**	**114.03**	**127.68**	**126.82**	**124.98**
Net Imports - Petroleum	**21.12**	**25.80**	**25.79**	**25.63**	**29.28**	**29.13**	**29.10**	**34.78**	**34.53**	**34.43**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.22	20.83	20.83	20.83	21.37	21.37	21.37	22.41	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.99	3.06	3.02	2.82	2.98	2.96	3.10	3.41	3.55
Coal Minemouth Price (dollars per ton)	17.13	15.22	15.00	15.21	14.19	15.03	15.25	12.93	13.38	12.75
Average Electric Price (cents per Kwh)	6.7	6.4	6.5	6.5	6.1	6.2	6.2	6.1	6.5	7.1

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 natural gas values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 petroleum values: EIA, *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC, June 2000). Other 1999 values: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000) and EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2005 Reference	2005 75 Percent	2005 75 Percent with CO_2 Cap	2010 Reference	2010 75 Percent	2010 75 Percent with CO_2 Cap	2020 Reference	2020 75 Percent	2020 75 Percent with CO_2 Cap
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.80	0.80	0.76	0.76	0.76
Kerosene	0.10	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.46	0.46	0.46	0.43	0.43	0.43	0.41	0.41	0.42
Petroleum Subtotal	1.42	1.41	1.41	1.41	1.30	1.31	1.30	1.23	1.24	1.25
Natural Gas	4.88	5.55	5.54	5.54	5.54	5.52	5.51	6.08	6.01	5.99
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Electricity	3.91	4.56	4.54	4.54	4.91	4.87	4.87	5.69	5.61	5.49
Delivered Energy	**10.66**	**11.99**	**11.97**	**11.97**	**12.22**	**12.17**	**12.16**	**13.48**	**13.35**	**13.20**
Electricity Related Losses	8.44	9.66	9.47	9.48	10.00	9.72	9.76	10.65	10.42	9.86
Total	**19.10**	**21.65**	**21.44**	**21.45**	**22.22**	**21.90**	**21.92**	**24.14**	**23.77**	**23.06**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.37	0.37	0.37
Residual Fuel	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Kerosene	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.60	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62
Natural Gas	3.14	3.99	3.98	3.99	4.19	4.16	4.16	4.47	4.41	4.40
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Electricity	3.66	4.40	4.38	4.39	4.92	4.90	4.91	5.64	5.58	5.48
Delivered Energy	**7.55**	**9.15**	**9.12**	**9.13**	**9.88**	**9.83**	**9.84**	**10.88**	**10.77**	**10.67**
Electricity Related Losses	7.91	9.33	9.13	9.16	10.02	9.78	9.84	10.56	10.36	9.84
Total	**15.46**	**18.48**	**18.25**	**18.30**	**19.90**	**19.61**	**19.68**	**21.44**	**21.13**	**20.51**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.22	1.21	1.30	1.30	1.30	1.49	1.49	1.49
Liquefied Petroleum Gas	2.32	2.44	2.46	2.44	2.51	2.51	2.52	2.85	2.86	2.87
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.27	0.28	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.25	0.25	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.41	4.45	4.42	4.68	4.71	4.68	5.00	5.03	5.04
Petroleum Subtotal	9.45	9.81	9.88	9.82	10.51	10.55	10.53	11.58	11.64	11.66
Natural Gas[6]	9.80	10.42	10.43	10.41	11.27	11.30	11.26	12.71	12.74	12.77
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.80	1.81	1.80	1.82	1.75	1.77	1.86	1.71	1.69
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.58	2.58	2.52	2.53	2.59	2.43	2.41
Renewable Energy[7]	2.15	2.40	2.42	2.40	2.63	2.64	2.63	3.07	3.08	3.08
Electricity	3.61	3.88	3.89	3.87	4.16	4.17	4.15	4.76	4.73	4.66
Delivered Energy	**27.56**	**29.10**	**29.21**	**29.08**	**31.14**	**31.17**	**31.10**	**34.72**	**34.63**	**34.58**
Electricity Related Losses	7.80	8.21	8.11	8.08	8.47	8.31	8.33	8.91	8.79	8.37
Total	**35.36**	**37.31**	**37.32**	**37.16**	**39.61**	**39.49**	**39.43**	**43.63**	**43.41**	**42.95**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Transportation										
Distillate Fuel	5.13	6.25	6.27	6.24	6.98	6.98	6.96	8.21	8.20	8.17
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Motor Gasoline[2]	15.92	17.64	17.68	17.64	18.94	18.97	18.94	21.25	21.26	21.24
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86
Liquefied Petroleum Gas	0.02	0.03	0.03	0.03	0.04	0.05	0.04	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.30	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	28.95	29.03	28.93	31.62	31.67	31.60	36.70	36.71	36.65
Pipeline Fuel Natural Gas	0.66	0.82	0.84	0.84	0.90	0.93	0.93	1.10	1.12	1.14
Compressed Natural Gas	0.02	0.05	0.06	0.05	0.09	0.09	0.09	0.16	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.09	0.09	0.09	0.12	0.12	0.12	0.17	0.17	0.17
Delivered Energy	**26.28**	**29.94**	**30.04**	**29.94**	**32.77**	**32.84**	**32.77**	**38.16**	**38.20**	**38.15**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.24	0.24	0.31	0.31	0.30
Total	**26.41**	**30.12**	**30.22**	**30.12**	**33.01**	**33.08**	**33.01**	**38.47**	**38.51**	**38.45**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.70	8.73	8.70	9.46	9.47	9.44	10.82	10.83	10.80
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.04	3.02	3.07	3.08	3.09	3.41	3.42	3.44
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.25	19.21	21.56	21.57	21.55
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.23	1.24	1.24
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.96	5.33	5.36	5.37
Petroleum Subtotal	37.01	40.77	40.92	40.77	44.05	44.14	44.05	50.13	50.21	50.18
Natural Gas[6]	18.50	20.84	20.85	20.83	21.99	21.99	21.95	24.52	24.45	24.46
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.94	1.88	1.89	1.99	1.83	1.81
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.70	2.71	2.70	2.70	2.64	2.65	2.71	2.56	2.53
Renewable Energy[13]	2.65	2.93	2.94	2.93	3.17	3.18	3.17	3.64	3.64	3.63
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.24	12.93	12.90	12.89	14.10	14.06	14.05	16.25	16.09	15.80
Delivered Energy	**72.05**	**80.17**	**80.33**	**80.12**	**86.01**	**86.01**	**85.87**	**97.25**	**96.95**	**96.60**
Electricity Related Losses	24.28	27.39	26.90	26.91	28.73	28.05	28.16	30.43	29.88	28.37
Total	**96.33**	**107.5**	**107.2**	**107.0**	**114.7**	**114.0**	**114.0**	**127.6**	**126.8**	**124.9**
Electric Generators[14]										
Distillate Fuel	0.05	0.06	0.05	0.05	0.06	0.03	0.04	0.06	0.03	0.03
Residual Fuel	0.86	0.37	0.25	0.25	0.20	0.11	0.13	0.17	0.09	0.09
Petroleum Subtotal	0.91	0.43	0.30	0.29	0.25	0.15	0.16	0.23	0.12	0.11
Natural Gas	3.83	5.54	5.82	5.79	6.96	7.67	7.89	11.36	12.30	12.94
Steam Coal	18.75	21.67	20.87	20.86	22.87	21.30	20.92	23.59	21.79	18.69
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.79	7.79	6.51	6.54	6.74
Renewable Energy[15]	3.88	4.17	4.31	4.35	4.70	4.83	5.07	4.75	4.96	5.44
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**35.52**	**40.32**	**39.80**	**39.80**	**42.83**	**42.11**	**42.21**	**46.68**	**45.97**	**44.17**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections 2005			Projections 2010			Projections 2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Total Energy Consumption										
Distillate Fuel	7.53	8.77	8.78	8.75	9.51	9.50	9.47	10.88	10.86	10.82
Kerosene	0.15	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.88	3.90	3.88	4.49	4.51	4.49	5.96	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.04	3.02	3.07	3.08	3.09	3.41	3.42	3.44
Motor Gasoline[2]	16.17	17.90	17.93	17.89	19.22	19.25	19.21	21.56	21.57	21.55
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.69	1.70	1.69
Residual Fuel	1.92	1.48	1.35	1.35	1.39	1.31	1.33	1.41	1.33	1.33
Other Petroleum[12]	4.53	4.68	4.72	4.69	4.96	4.99	4.96	5.33	5.36	5.37
Petroleum Subtotal	37.92	41.21	41.22	41.06	44.30	44.29	44.21	50.36	50.33	50.29
Natural Gas	22.32	26.38	26.67	26.62	28.94	29.66	29.85	35.88	36.74	37.40
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.59	23.59	22.79	22.78	24.81	23.18	22.81	25.58	23.63	20.50
Net Coal Coke Imports	0.06	0.11	0.12	0.11	0.15	0.16	0.15	0.22	0.22	0.22
Coal Subtotal	21.40	24.37	23.57	23.56	25.57	23.94	23.57	26.30	24.35	21.22
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.79	7.79	6.51	6.54	6.74
Renewable Energy[17]	6.53	7.10	7.25	7.28	7.87	8.01	8.24	8.38	8.60	9.08
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**96.33**	**107.56**	**107.23**	**107.03**	**114.74**	**114.07**	**114.03**	**127.68**	**126.82**	**124.98**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.17	80.33	80.12	86.01	86.01	85.87	97.25	96.95	96.60
Total Energy Use	96.33	107.56	107.23	107.03	114.74	114.07	114.03	127.68	126.82	124.98
Population (millions)	273.13	288.02	288.02	288.02	300.17	300.17	300.17	325.24	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10908	10960	10904	12634	12667	12634	16509	16515	16513
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1701.4	1684.7	1680.9	1820.6	1787.8	1779.4	2043.8	2004.5	1933.9

[1]Includes wood used for residential heating.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass.
[4]Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8]Includes only kerosene type.
[9]Includes aviation gas and lubricants.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11]M85 is 85 percent methanol and 15 percent motor gasoline.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 1999 electric utility fuel consumption: Energy Information Administration, (EIA) *Electric Power Annual 1998, Volume 1,* DOE/EIA-0348(98)/1 (Washington, DC, April 1999). 1999 nonutility consumption estimates: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999 values: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Residential	**13.18**	**13.33**	**13.51**	**13.44**	**13.41**	**13.73**	**13.69**	**13.62**	**14.21**	**14.93**
Primary Energy[1]	6.71	7.50	7.56	7.53	7.17	7.30	7.29	7.01	7.26	7.34
Petroleum Products[2]	7.55	9.17	9.17	9.16	9.37	9.38	9.38	9.47	9.48	9.38
Distillate Fuel	6.27	7.37	7.38	7.37	7.57	7.57	7.57	7.76	7.75	7.74
Liquefied Petroleum Gas	10.36	12.61	12.62	12.61	12.82	12.81	12.84	12.71	12.74	12.43
Natural Gas	6.52	7.13	7.20	7.17	6.70	6.86	6.85	6.56	6.86	6.96
Electricity	23.69	22.29	22.67	22.55	22.19	22.81	22.71	22.16	23.25	25.00
Commercial	**13.28**	**12.71**	**12.94**	**12.86**	**12.23**	**12.43**	**12.40**	**12.55**	**13.23**	**14.27**
Primary Energy[1]	5.22	5.58	5.63	5.60	5.65	5.78	5.77	5.69	5.94	6.02
Petroleum Products[2]	4.99	6.08	6.08	6.07	6.27	6.26	6.27	6.37	6.36	6.31
Distillate Fuel	4.37	5.17	5.17	5.16	5.35	5.35	5.35	5.51	5.50	5.49
Residual Fuel	2.63	3.64	3.63	3.63	3.70	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.57	5.63	5.60	5.63	5.78	5.77	5.67	5.96	6.06
Electricity	21.64	20.28	20.70	20.57	18.76	19.00	18.95	18.83	19.90	21.95
Industrial[4]	**5.29**	**5.75**	**5.82**	**5.78**	**5.62**	**5.72**	**5.71**	**5.82**	**6.10**	**6.33**
Primary Energy	3.91	4.46	4.50	4.48	4.45	4.52	4.52	4.61	4.77	4.76
Petroleum Products[2]	5.54	5.97	5.97	5.97	6.07	6.07	6.09	6.12	6.13	5.97
Distillate Fuel	4.65	5.33	5.33	5.32	5.53	5.54	5.53	5.71	5.70	5.69
Liquefied Petroleum Gas	8.50	7.75	7.76	7.76	7.77	7.75	7.80	7.68	7.72	7.42
Residual Fuel	2.78	3.37	3.36	3.36	3.43	3.42	3.42	3.58	3.57	3.57
Natural Gas[5]	2.79	3.66	3.73	3.70	3.46	3.62	3.59	3.73	4.03	4.16
Metallurgical Coal	1.66	1.58	1.58	1.58	1.54	1.54	1.54	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.34	1.34	1.30	1.30	1.30	1.21	1.19	1.26
Electricity	13.12	12.81	13.06	12.96	12.04	12.22	12.17	12.07	13.01	14.60
Transportation	**8.30**	**9.33**	**9.34**	**9.33**	**9.63**	**9.67**	**9.68**	**9.20**	**9.22**	**9.22**
Primary Energy	8.29	9.32	9.32	9.32	9.61	9.65	9.66	9.18	9.20	9.19
Petroleum Products[2]	8.28	9.32	9.32	9.31	9.61	9.65	9.66	9.18	9.20	9.19
Distillate Fuel[6]	8.22	8.89	8.90	8.89	8.94	8.95	8.94	8.83	8.82	8.83
Jet Fuel[7]	4.70	5.22	5.23	5.22	5.49	5.49	5.49	5.72	5.72	5.71
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.26	11.28	10.60	10.63	10.62
Residual Fuel	2.46	3.11	3.10	3.10	3.18	3.18	3.18	3.33	3.32	3.32
Liquid Petroleum Gas[9]	12.87	14.07	14.08	14.07	14.00	13.98	14.07	13.64	13.66	13.40
Natural Gas[10]	7.02	7.30	7.37	7.34	7.17	7.32	7.32	7.30	7.58	7.69
Ethanol (E85)[11]	14.42	19.20	19.21	19.21	19.13	19.16	19.17	19.34	19.39	19.40
Methanol (M85)[12]	10.38	13.13	13.20	13.16	13.80	13.82	13.82	14.35	14.36	14.36
Electricity	15.64	14.61	14.79	14.74	13.73	14.22	14.18	13.18	13.81	14.58
Average End-Use Energy	**8.52**	**9.16**	**9.23**	**9.20**	**9.16**	**9.28**	**9.27**	**9.13**	**9.39**	**9.68**
Primary Energy	6.31	7.16	7.19	7.17	7.30	7.37	7.37	7.20	7.31	7.31
Electricity	19.58	18.71	19.05	18.94	17.93	18.27	18.21	17.96	18.98	20.76
Electric Generators[13]										
Fossil Fuel Average	1.48	1.63	1.69	1.67	1.59	1.70	1.73	1.85	2.05	2.30
Petroleum Products	2.48	3.60	3.70	3.70	3.96	4.21	4.13	4.20	4.56	4.55
Distillate Fuel	4.07	4.65	4.68	4.67	4.85	4.88	4.87	5.05	5.06	5.08
Residual Fuel	2.39	3.43	3.50	3.51	3.70	4.00	3.92	3.92	4.37	4.39
Natural Gas	2.57	3.42	3.56	3.53	3.23	3.48	3.47	3.62	3.97	4.16
Steam Coal	1.21	1.13	1.13	1.13	1.06	1.04	1.05	0.98	0.96	0.99

Table D3. Energy Prices by Sector and Source (Continued)

(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Average Price to All Users[14]										
Petroleum Products[2]	7.46	8.48	8.50	8.50	8.75	8.79	8.80	8.49	8.51	8.46
Distillate Fuel	7.25	8.06	8.07	8.06	8.20	8.21	8.20	8.20	8.19	8.19
Jet Fuel	4.70	5.22	5.23	5.22	5.49	5.49	5.49	5.72	5.72	5.71
Liquefied Petroleum Gas	8.84	8.65	8.65	8.66	8.66	8.65	8.69	8.48	8.52	8.22
Motor Gasoline[8]	9.45	10.75	10.75	10.75	11.20	11.26	11.28	10.60	10.63	10.62
Residual Fuel	2.47	3.25	3.24	3.24	3.33	3.33	3.33	3.49	3.48	3.48
Natural Gas	4.04	4.73	4.80	4.77	4.43	4.58	4.56	4.50	4.78	4.91
Coal	1.23	1.15	1.15	1.15	1.08	1.07	1.07	0.99	0.98	1.01
Ethanol (E85)[11]	14.42	19.20	19.21	19.21	19.13	19.16	19.17	19.34	19.39	19.40
Methanol (M85)[12]	10.38	13.13	13.20	13.16	13.80	13.82	13.82	14.35	14.36	14.36
Electricity	19.58	18.71	19.05	18.94	17.93	18.27	18.21	17.96	18.98	20.76
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	135.11	154.2	155.9	155.1	158.2	161.3	160.6	177.6	183.5	190.7
Commercial	99.11	115.3	116.8	116.3	119.8	121.1	120.9	135.5	141.3	151.0
Industrial	112.11	126.4	128.3	127.0	131.8	134.1	133.5	152.0	159.1	165.4
Transportation	212.64	271.3	272.2	271.2	306.1	307.8	307.5	340.1	341.0	340.3
Total Non-Renewable Expenditures	558.97	667.3	673.4	669.7	716.0	724.4	722.6	805.4	825.1	847.5
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.62	0.63	0.63	0.85	0.85	0.85
Total Expenditures	**559.11**	**667.7**	**673.8**	**670.1**	**716.6**	**725.0**	**723.2**	**806.2**	**825.9**	**848.3**

[1]Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Excludes independent power producers.
[4]Includes cogenerators.
[5]Excludes uses for lease and plant fuel.
[6] Low sulfur diesel fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7]Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[8]Sales weighted-average price for all grades. Includes Federal and State taxes and excludes county and local taxes.
[9]Includes Federal and State taxes while excluding county and local taxes.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[12]M85 is 85 percent methanol and 15 percent motor gasoline.
[13]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[14]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 prices for gasoline, distillate, and jet fuel are based on prices in various issues of Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380 (99/03-2000/04) (Washington, DC, 1999-2000). 1999 prices for all other petroleum products are derived from the EIA, *State Energy Price and Expenditure Report 1997*, DOE/EIA-0376(97) (Washington, DC, July 2000). 1999 industrial gas delivered prices are based on EIA, *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 coal prices based on EIA, *Quarterly Coal Report*, DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Generation by Fuel Type										
Electric Generators[1]										
Coal	1830	2105	2029	2027	2238	2068	2022	2302	2083	1794
Petroleum	85	42	30	29	25	15	17	23	13	13
Natural Gas[2]	370	582	654	651	826	984	1016	1488	1661	1816
Nuclear Power	730	740	740	740	720	729	729	610	613	631
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	372	380	381	396	401	409	399	411	442
Total	**3369**	**3839**	**3832**	**3828**	**4204**	**4196**	**4191**	**4821**	**4781**	**4694**
Non-Utility Generation for Own Use	16	17	17	17	17	16	16	16	16	22
Distributed Generation	0	0	0	0	1	1	1	5	4	4
Cogenerators[4]										
Coal	47	53	52	52	51	47	48	52	38	36
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	236	237	237	259	259	258	317	327	344
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	9
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	6	6	6
Total	**303**	**344**	**345**	**345**	**372**	**367**	**368**	**440**	**437**	**452**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	170	170	179	174	175	208	198	200
Generation for Own Use	156	177	179	179	197	198	198	237	244	257
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1337	1332	1331	1438	1428	1427	1668	1645	1609
Commercial	1073	1291	1284	1286	1442	1436	1439	1653	1635	1607
Industrial	1058	1137	1140	1134	1219	1221	1217	1394	1387	1367
Transportation	17	26	26	26	34	35	34	49	49	49
Total	**3294**	**3790**	**3781**	**3777**	**4133**	**4120**	**4117**	**4763**	**4716**	**4631**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.1	7.6	7.7	7.7	7.6	7.8	7.7	7.6	7.9	8.5
Commercial	7.4	6.9	7.1	7.0	6.4	6.5	6.5	6.4	6.8	7.5
Industrial	4.5	4.4	4.5	4.4	4.1	4.2	4.2	4.1	4.4	5.0
Transportation	5.3	5.0	5.0	5.0	4.7	4.9	4.8	4.5	4.7	5.0
All Sectors Average	**6.7**	**6.4**	**6.5**	**6.5**	**6.1**	**6.2**	**6.2**	**6.1**	**6.5**	**7.1**
Prices by Service Category [9] (1999 cents per kwh)										
Generation	4.1	3.8	3.9	3.9	3.4	3.5	3.5	3.5	3.9	4.5
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.49	10.39	7.98	7.98	9.70	5.51	5.51	8.95	2.24	2.24
Nitrogen Oxide	5.43	4.30	4.18	4.18	4.34	2.34	2.41	4.48	1.64	1.42

[1]Includes grid-connected generation at all utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[2] Includes electricity generation by fuel cells.
[3]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[4]Cogenerators produce electricity and other useful thermal energy. Includes sales to utilities and generation for own use.
[5]Other gaseous fuels include refinery and still gas.
[6]Other includes hydrogen, sulfur, batteries, chemicals, fish oil, and spent sulfite liquor.
[7]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[9]Prices represent average revenue per kilowatthour.
Kwh = Kilowatthour.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.0	302.8	317.8	303.4	294.2	317.3	300.4	288.6
Other Fossil Steam[3]	137.4	124.9	120.6	120.9	117.4	107.7	109.2	114.9	106.7	107.5
Combined Cycle	21.0	52.4	78.9	78.6	107.3	154.5	159.0	199.0	233.0	246.3
Combustion Turbine/Diesel	86.8	126.4	125.6	126.5	149.8	138.2	139.5	197.4	185.7	171.2
Nuclear Power	97.4	97.5	97.5	97.5	93.7	95.3	95.3	76.3	76.3	78.8
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	88.8	94.7	95.1	95.4	97.9	98.5	99.5	99.4	100.1	101.3
Distributed Generation[5]	0.0	0.8	0.2	0.2	2.5	1.6	1.9	11.0	9.2	8.6
Total	755.9	820.0	840.4	841.3	906.0	918.9	918.2	1035.1	1031.2	1022.0
Cumulative Planned Additions[6]										
Coal Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	0.0	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Combustion Turbine/Diesel	0.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	5.1	5.1	5.1	6.7	6.7	6.7	8.1	8.1	8.1
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**32.0**	**32.0**	**32.0**	**33.7**	**33.7**	**33.7**	**35.3**	**35.3**	**35.3**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	1.1	0.2	0.0	18.2	9.2	0.0	19.5	9.2	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	18.6	45.1	44.9	73.6	120.8	125.3	165.4	199.3	212.6
Combustion Turbine/Diesel	0.0	30.9	23.1	23.9	55.4	38.1	39.1	103.1	85.7	70.9
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	0.8	1.1	1.9	2.6	3.5	1.9	2.7	3.9
Distributed Generation[5]	0.0	0.8	0.2	0.2	2.5	1.6	1.9	11.0	9.2	8.6
Total	**0.0**	**51.7**	**69.4**	**69.9**	**151.5**	**172.2**	**169.9**	**300.8**	**306.1**	**295.9**
Cumulative Total Additions	**0.0**	**83.7**	**101.4**	**101.9**	**185.2**	**205.9**	**203.6**	**336.1**	**341.4**	**331.2**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.5	11.0	10.9	7.3	14.0	16.5
Other Fossil Steam[3]	0.0	12.7	17.0	16.8	20.2	29.9	28.5	22.7	31.0	30.1
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.1	0.1	0.2	0.1	0.1
Combustion Turbine/Diesel	0.0	5.5	5.5	5.3	6.6	7.8	7.6	6.7	7.9	7.7
Nuclear Power	0.0	0.0	0.0	0.0	3.7	2.2	2.2	21.2	21.2	18.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**20.6**	**25.0**	**24.6**	**36.4**	**51.1**	**49.4**	**58.1**	**74.3**	**73.3**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.5	7.7	8.6	6.4	6.4
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Natural Gas	34.6	39.7	40.1	40.0	43.1	43.3	43.2	51.2	52.6	54.9
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.1	1.1
Renewable Sources[4]	5.4	5.9	5.9	5.9	6.8	6.8	6.8	8.3	8.2	8.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.1**	**59.4**	**59.4**	**63.1**	**62.3**	**62.4**	**73.0**	**72.2**	**74.6**
Cumulative Additions[6]	**0.0**	**6.7**	**7.0**	**7.0**	**10.7**	**9.8**	**9.9**	**20.5**	**19.8**	**22.2**

Table D5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Other End-Use Generators[9]										
Renewable Sources	1.0	1.1	1.1	1.1	1.3	1.3	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3

[1]Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes grid-connected utilities and nonutilities except for cogenerators. Includes small power producers and exempt wholesale generators.
[3]Includes oil-, gas-, and dual-fired capability.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar and wind power.
[5]Primarily peak-load capacity fueled by natural gas.
[6]Cumulative additions after December 31, 1999.
[7]Cumulative total retirements after December 31, 1999.
[8]Nameplate capacity is reported for nonutilities on Form EIA-860B, "Annual Electric Generator Report - Nonutility." Nameplate capacity is designated by the manufacturer. The nameplate capacity has been converted to the net summer capability based on historic relationships.
[9]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Interregional Electricity Trade										
Gross Domestic Firm Power Trade	182.2	125.3	125.3	125.3	102.9	102.9	102.9	0.0	0.0	0.0
Gross Domestic Economy Trade	152.1	199.1	207.8	209.1	154.6	154.0	154.8	146.4	132.0	120.4
Gross Domestic Trade	**334.3**	**324.4**	**333.1**	**334.4**	**257.5**	**256.9**	**257.7**	**146.4**	**132.0**	**120.4**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.8	5905.8	5905.8	4851.2	4851.2	4851.2	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4204.3	6352.8	6889.5	6864.0	4407.4	4610.3	4633.0	4448.7	4582.4	4886.1
Gross Domestic Sales (million 1999 dollars)	**12792.4**	**12258.**	**12795.**	**12769.**	**9258.7**	**9461.6**	**9484.3**	**4448.7**	**4582.4**	**4886.1**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	10.7	5.8	5.8	5.8	0.0	0.0	0.0
Economy Imports From Canada and Mexico[1]	21.9	63.5	63.5	63.5	45.9	45.9	45.9	30.6	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**74.1**	**74.1**	**74.1**	**51.7**	**51.7**	**51.7**	**30.6**	**30.6**	**30.6**
Firm Power Exports To Canada and Mexico	9.2	9.7	9.7	9.7	8.7	8.7	8.7	0.0	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.0	7.0	7.0	7.7	7.7	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.7**	**16.7**	**16.7**	**16.4**	**16.4**	**16.4**	**7.7**	**7.7**	**7.7**

[1]Historically electricity imports were primarily from renewable resources, principally hydroelectric.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Production										
Dry Gas Production[1]	18.67	21.32	21.59	21.55	23.36	23.95	24.14	29.34	30.00	30.64
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.11	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.70**	**4.73**	**4.71**	**5.01**	**5.15**	**5.12**	**5.78**	**5.97**	**6.00**
Canada	3.29	4.49	4.51	4.50	4.72	4.86	4.83	5.39	5.58	5.61
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	-0.25	-0.25	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	0.54	0.54	0.79	0.80	0.80
Total Supply	**22.15**	**26.14**	**26.43**	**26.38**	**28.42**	**29.15**	**29.32**	**35.17**	**36.03**	**36.70**
Consumption by Sector										
Residential	4.75	5.40	5.40	5.40	5.39	5.37	5.37	5.92	5.86	5.83
Commercial	3.06	3.89	3.88	3.88	4.08	4.05	4.05	4.36	4.29	4.29
Industrial[3]	8.31	8.78	8.79	8.76	9.48	9.48	9.43	10.52	10.51	10.51
Electric Generators[4]	3.76	5.44	5.71	5.68	6.83	7.53	7.75	11.15	12.07	12.70
Lease and Plant Fuel[5]	1.23	1.36	1.37	1.37	1.50	1.53	1.53	1.86	1.90	1.93
Pipeline Fuel	0.64	0.80	0.82	0.81	0.88	0.91	0.91	1.07	1.10	1.11
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.77**	**25.73**	**26.02**	**25.96**	**28.24**	**28.94**	**29.13**	**35.03**	**35.87**	**36.52**
Discrepancy[7]	**0.38**	**0.41**	**0.41**	**0.41**	**0.19**	**0.21**	**0.20**	**0.15**	**0.16**	**0.18**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Represents natural gas used in the field gathering and processing plant machinery.
[6]Compressed natural gas used as vehicle fuel.
[7]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 1999 values include net storage injections.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 supplemental natural gas: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). 1999 transportation sector consumption: EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B. Other 1999 consumption: EIA, *Short-Term Energy Outlook, April 2001,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr01.pdf with adjustments to end-use sector consumption levels for consumption of natural gas by electric wholesale generators based on EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D8. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.99	3.06	3.02	2.82	2.98	2.96	3.10	3.41	3.55
Average Import Price	2.29	2.99	3.01	3.00	2.66	2.71	2.70	2.71	2.81	2.82
Average[2]	**2.11**	**2.99**	**3.05**	**3.02**	**2.79**	**2.93**	**2.91**	**3.03**	**3.30**	**3.42**
Delivered Prices										
Residential	6.69	7.33	7.39	7.36	6.88	7.04	7.03	6.74	7.04	7.15
Commercial	5.49	5.72	5.79	5.75	5.78	5.94	5.92	5.82	6.12	6.23
Industrial[3]	2.87	3.76	3.83	3.80	3.55	3.71	3.69	3.84	4.14	4.27
Electric Generators[4]	2.62	3.49	3.63	3.59	3.30	3.55	3.54	3.68	4.04	4.24
Transportation[5]	7.21	7.50	7.57	7.53	7.36	7.52	7.52	7.50	7.79	7.90
Average[6]	**4.14**	**4.85**	**4.92**	**4.89**	**4.55**	**4.70**	**4.68**	**4.61**	**4.91**	**5.04**
Transmission & Distribution Margins[7]										
Residential	4.58	4.34	4.35	4.34	4.09	4.11	4.12	3.71	3.74	3.73
Commercial	3.37	2.73	2.74	2.74	2.99	3.01	3.01	2.79	2.81	2.81
Industrial[3]	0.76	0.78	0.79	0.78	0.76	0.78	0.78	0.81	0.84	0.85
Electric Generators[4]	0.51	0.50	0.58	0.58	0.51	0.61	0.62	0.66	0.74	0.82
Transportation[5]	5.10	4.52	4.52	4.52	4.57	4.59	4.60	4.47	4.48	4.48
Average[6]	**2.03**	**1.87**	**1.87**	**1.87**	**1.76**	**1.77**	**1.76**	**1.59**	**1.60**	**1.62**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.45	23.46	23.46	22.07	22.09	22.10	21.95	21.88	21.75
Commercial	10.32	10.62	10.61	10.62	12.19	12.17	12.19	12.16	12.08	12.04
Industrial[3]	6.28	6.82	6.90	6.86	7.20	7.40	7.33	8.50	8.82	8.93
Electric Generators[4]	1.90	2.74	3.32	3.28	3.46	4.62	4.81	7.33	8.93	10.46
Transportation[5]	0.08	0.24	0.24	0.24	0.40	0.41	0.41	0.68	0.67	0.67
Total	**40.35**	**43.87**	**44.53**	**44.45**	**45.33**	**46.69**	**46.82**	**50.61**	**52.38**	**53.86**

[1]Represents lower 48 onshore and offshore supplies.
[2]Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[6]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[7]Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1994*. 1999 residential and commercial delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). **Other 1999 values, and projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D9. Oil and Gas Supply

Production and Supply	1999	Projections 2005 Reference	2005 75 Percent	2005 75 Percent with CO_2 Cap	2010 Reference	2010 75 Percent	2010 75 Percent with CO_2 Cap	2020 Reference	2020 75 Percent	2020 75 Percent with CO_2 Cap
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	16.49	**20.48**	**21.14**	**20.45**	**20.80**	**20.80**	**20.80**	**21.50**	**21.50**	**21.46**
Production (million barrels per day)[2]										
U.S. Total	5.88	**5.69**	**5.67**	**5.68**	**5.30**	**5.32**	**5.30**	**5.22**	**5.27**	**5.27**
Lower 48 Onshore	3.27	2.80	2.80	2.80	2.50	2.51	2.50	2.71	2.76	2.76
Conventional	2.59	2.18	2.18	2.18	1.81	1.81	1.81	1.96	2.00	2.00
Enhanced Oil Recovery	0.68	0.62	0.62	0.62	0.69	0.70	0.69	0.74	0.76	0.76
Lower 48 Offshore	1.56	2.09	2.08	2.09	2.16	2.16	2.16	1.88	1.88	1.87
Alaska	1.05	0.79	0.79	0.79	0.65	0.65	0.65	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	18.33	**15.76**	**15.76**	**15.76**	**14.43**	**14.56**	**14.48**	**14.01**	**14.15**	**14.14**
Natural Gas										
Lower 48 Average Wellhead Price[3] (1999 dollars per thousand cubic feet)	2.08	**2.99**	**3.06**	**3.02**	**2.82**	**2.98**	**2.96**	**3.10**	**3.41**	**3.55**
Production (trillion cubic feet)[3]										
U.S. Total	18.67	**21.32**	**21.59**	**21.55**	**23.36**	**23.95**	**24.14**	**29.34**	**30.00**	**30.64**
Lower 48 Onshore	12.83	14.37	14.57	14.53	16.42	17.11	17.11	21.10	21.85	22.28
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.33	1.32	1.38	1.40	1.40
Non-Associated	11.03	12.86	13.05	13.02	15.10	15.79	15.79	19.72	20.45	20.88
Conventional	6.64	7.62	7.76	7.72	7.79	8.09	8.09	11.05	11.27	11.56
Unconventional	4.39	5.24	5.29	5.30	7.30	7.70	7.70	8.66	9.18	9.32
Lower 48 Offshore	5.43	6.49	6.56	6.55	6.44	6.33	6.53	7.66	7.58	7.79
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.04	1.04
Non-Associated	4.50	5.42	5.50	5.49	5.35	5.24	5.44	6.63	6.54	6.75
Alaska	0.42	0.47	0.47	0.47	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves (trillion cubic feet)	157.41	**169.38**	**168.78**	**168.99**	**184.15**	**187.65**	**186.76**	**199.35**	**203.04**	**198.70**
Supplemental Gas Supplies (trillion cubic feet)[5]	0.10	**0.11**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	17.93	**29.02**	**29.31**	**29.07**	**29.30**	**30.35**	**30.39**	**38.07**	**41.64**	**41.81**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Market production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 1999,* DOE/EIA-0340(99/1) (Washington, DC. June 2000). 1999 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2000/06) (Washington, DC, June 2000). Other 1999 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Production[1]										
Appalachia	434	432	411	417	425	422	422	396	371	329
Interior	182	185	162	168	183	169	173	164	152	133
West	486	612	615	600	681	597	568	775	686	596
East of the Mississippi	558	569	533	544	564	558	563	526	513	444
West of the Mississippi	544	659	656	641	725	630	600	810	696	615
Total	**1102**	**1228**	**1188**	**1185**	**1289**	**1188**	**1163**	**1336**	**1209**	**1059**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	58	58	56	55	56
Total	**-49**	**-44**	**-45**	**-45**	**-40**	**-40**	**-41**	**-36**	**-36**	**-37**
Total Supply[2]	**1053**	**1184**	**1144**	**1140**	**1249**	**1148**	**1122**	**1300**	**1173**	**1022**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	80	81	85	78	77
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	920	1073	1033	1029	1139	1038	1014	1190	1070	930
Total	**1031**	**1185**	**1146**	**1141**	**1250**	**1146**	**1123**	**1299**	**1173**	**1031**
Discrepancy and Stock Change[5]	**21**	**-1**	**-2**	**-1**	**-1**	**2**	**-1**	**1**	**1**	**-9**
Average Minemouth Price										
(1999 dollars per short ton)	17.13	15.22	15.00	15.21	14.19	15.03	15.25	12.93	13.38	12.75
(1999 dollars per million Btu)	0.82	0.74	0.72	0.73	0.69	0.72	0.72	0.64	0.64	0.62
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.37	29.65	29.29	29.32	28.56	28.54	28.47	26.49	25.95	27.47
Coke Plants	44.38	42.40	42.39	42.32	41.25	41.32	41.25	38.50	38.60	38.50
Electric Generators										
(1999 dollars per short ton)	24.69	22.92	22.88	22.90	21.26	21.45	21.62	19.34	19.53	19.90
(1999 dollars per million Btu)	1.21	1.13	1.13	1.13	1.06	1.04	1.05	0.98	0.96	0.99
Average	**25.74**	**23.80**	**23.77**	**23.79**	**22.11**	**22.34**	**22.51**	**20.09**	**20.27**	**20.81**
Exports[7]	37.50	36.41	36.12	36.08	35.57	35.50	35.42	33.07	32.75	32.28

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 8.5 million tons in 1995, 8.8 million tons in 1996, 8.1 million tons in 1997, 8.6 million tons in 1998, and are projected to reach 9.6 million tons in 1999, and 12.2 million tons in 2000.
[2]Production plus net imports and net storage withdrawals.
[3]Includes consumption by cogenerators.
[4]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[5]Balancing item: the sum of production, net imports, and net storage minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 data based on Energy Information Administration (EIA), *Quarterly Coal Report* , DOE/EIA-0121(2000/1Q) (Washington, DC, August 2000), and EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B. **Projections:** EIA, AEO2001 National Energy Modeling System runsSCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.26	79.26	79.38	79.38	79.38	79.38	79.38	79.38
Geothermal[2]	2.87	3.36	3.67	3.81	4.81	5.30	6.22	4.83	5.34	6.30
Municipal Solid Waste[3]	2.61	2.96	3.11	3.20	3.42	3.63	3.66	3.93	4.14	4.17
Wood and Other Biomass[4]	1.57	1.75	1.75	1.75	2.12	2.12	2.12	2.45	2.45	2.59
Solar Thermal	0.33	0.35	0.35	0.35	0.40	0.40	0.40	0.48	0.48	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.08	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.66	6.92	6.92	6.92	7.52	7.52	7.52	7.74	7.79	7.87
Total	**88.83**	**94.68**	**95.14**	**95.38**	**97.85**	**98.55**	**99.50**	**99.35**	**100.1**	**101.3**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.2	301.2	301.2	301.1	301.1	301.1	300.0	300.0	300.0
Geothermal[2]	13.21	17.71	20.30	21.48	29.92	33.96	41.62	30.13	34.34	42.28
Municipal Solid Waste[3]	18.12	20.68	21.85	22.59	23.88	25.51	25.71	27.76	29.39	29.62
Wood and Other Biomass[4]	8.76	14.92	18.88	18.39	21.22	20.31	20.68	19.29	25.33	47.90
Dedicated Plants	7.73	9.17	9.17	9.17	11.36	11.38	11.37	13.82	13.84	14.83
Cofiring	1.03	5.75	9.71	9.21	9.86	8.94	9.30	5.47	11.49	33.07
Solar Thermal	0.89	0.96	0.96	0.96	1.11	1.11	1.11	1.37	1.37	1.37
Solar Photovoltaic	0.03	0.20	0.20	0.20	0.51	0.51	0.51	1.36	1.36	1.36
Wind	4.61	16.30	16.30	16.30	18.16	18.16	18.16	18.77	18.94	19.19
Total	**355.16**	**371.9**	**379.6**	**381.1**	**395.9**	**400.6**	**408.9**	**398.7**	**410.7**	**441.7**
Cogenerators[5]										
Net Summer Capability										
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.19	5.17	5.19	6.09	6.06	6.10	7.59	7.54	7.59
Total	**5.35**	**5.89**	**5.87**	**5.89**	**6.79**	**6.76**	**6.80**	**8.29**	**8.24**	**8.29**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04
Biomass	27.08	30.04	29.92	30.03	35.20	35.01	35.20	43.82	43.52	43.83
Total	**31.12**	**34.08**	**33.97**	**34.07**	**39.24**	**39.05**	**39.25**	**47.87**	**47.57**	**47.88**
Other End-Use Generators[6]										
Net Summer Capability										
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.10	0.10	0.10	0.35	0.35	0.35	0.35	0.35	0.35
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.44	4.44	4.44	4.43	4.43	4.43	4.41	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.20	0.20	0.20	0.75	0.75	0.75	0.75	0.75	0.75
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.17**

[1]Includes grid-connected utilities and nonutilities other than cogenerators. These nonutility facilities include small power producers and exempt wholesale generators.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Includes projections for energy crops after 2010.
[5]Cogenerators produce electricity and other useful thermal energy.
[6]Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[7]Represents own-use industrial hydroelectric power.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports. Net summer capability has been estimated for nonutility generators for AEO2001. Net summer capability is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 1999 electric utility capability: Energy Information Administration (EIA), Form EIA-860A: "Annual Electric Generator Report - Utility." 1999 nonutility and cogenerator capability: EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." 1999 generation: EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.43**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.43	0.43
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.40**	**2.42**	**2.40**	**2.63**	**2.64**	**2.63**	**3.07**	**3.08**	**3.08**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.22	2.23	2.22	2.44	2.45	2.44	2.89	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.21	0.20	0.21
Electric Generators[5]	**3.88**	**4.17**	**4.31**	**4.35**	**4.70**	**4.83**	**5.07**	**4.75**	**4.96**	**5.44**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.10	3.10	3.10	3.08	3.08	3.08
Geothermal	0.28	0.42	0.51	0.54	0.82	0.94	1.17	0.82	0.95	1.19
Municipal Solid Waste[6]	0.25	0.28	0.30	0.31	0.32	0.35	0.35	0.38	0.40	0.40
Biomass	0.11	0.18	0.22	0.22	0.25	0.24	0.25	0.24	0.31	0.54
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.14	0.14	0.17	0.17	0.17
Cofiring	0.01	0.07	0.11	0.11	0.12	0.11	0.11	0.07	0.14	0.37
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.17	0.17	0.17	0.19	0.19	0.19	0.19	0.19	0.20
Total Marketed Renewable Energy	**6.64**	**7.27**	**7.42**	**7.45**	**8.05**	**8.19**	**8.42**	**8.58**	**8.79**	**9.27**
Non-Marketed Renewable Energy[7] Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**
Solar Hot Water Heating	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol										
From Corn	0.12	0.19	0.19	0.19	0.19	0.19	0.19	0.17	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.24**	**0.24**	**0.24**

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports.
[3]Includes all electricity production by industrial and other cogenerators for the grid and for own use.
[4]Excludes motor gasoline component of E85.
[5]Includes renewable energy delivered to the grid from electric utilities and nonutilities. Renewable energy used in generating electricity for own use is included in the individual sectoral electricity energy consumption values.
[6]Includes landfill gas.
[7]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
Btu = British thermal unit.
CO_2 = Carbon dioxide.
Notes: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 ethanol: Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). 1999 electric generators: EIA, Form EIA-860A: "Annual Electric Generator Report - Utility," and EIA, Form EIA-860B: "Annual Electric Generator Report - Nonutility." Other 1999: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Residential										
Petroleum	26.0	26.6	26.6	26.6	24.6	24.6	24.6	23.3	23.4	23.5
Natural Gas	69.5	79.9	79.8	79.8	79.8	79.5	79.4	87.5	86.6	86.2
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	226.8	219.6	219.5	240.3	228.0	225.7	270.7	257.2	232.0
Total	**290.1**	**334.5**	**327.3**	**327.2**	**346.0**	**333.4**	**331.0**	**382.7**	**368.5**	**343.0**
Commercial										
Petroleum	13.7	11.9	11.9	11.9	12.1	12.1	12.1	12.0	12.1	12.1
Natural Gas	45.4	57.5	57.3	57.4	60.3	59.9	59.9	64.4	63.5	63.4
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	219.0	211.7	212.1	241.0	229.3	227.6	268.3	255.6	231.7
Total	**242.1**	**290.1**	**282.7**	**283.1**	**315.1**	**303.1**	**301.4**	**346.6**	**333.2**	**309.2**
Industrial[1]										
Petroleum	104.2	98.8	99.5	98.9	104.6	104.9	104.8	113.0	113.8	114.2
Natural Gas[2]	141.6	147.7	148.0	147.6	159.5	160.3	159.6	180.1	180.6	181.2
Coal	55.9	65.6	65.7	65.5	65.4	63.8	64.0	65.6	61.7	61.1
Electricity	178.8	192.9	188.1	186.9	203.7	195.0	192.6	226.3	216.9	197.0
Total	**480.4**	**505.0**	**501.3**	**499.0**	**533.2**	**523.9**	**521.0**	**585.0**	**573.0**	**553.5**
Transportation										
Petroleum[3]	485.8	554.7	556.3	554.5	606.2	607.1	605.7	703.5	703.8	702.5
Natural Gas[4]	9.5	12.6	12.9	12.8	14.3	14.7	14.7	18.0	18.4	18.6
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.3	4.3	5.8	5.5	5.5	7.9	7.6	7.0
Total[3]	**498.2**	**571.8**	**573.5**	**571.6**	**626.3**	**627.4**	**626.0**	**729.5**	**729.9**	**728.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	692.0	694.2	691.8	747.4	748.7	747.2	851.8	853.1	852.4
Natural Gas	266.0	297.8	298.0	297.7	313.9	314.3	313.5	350.0	349.2	349.4
Coal	58.8	68.5	68.7	68.5	68.6	66.9	67.2	68.8	64.9	64.3
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	643.1	623.7	622.8	690.7	657.8	651.3	773.1	737.3	667.7
Total[3]	**1510.8**	**1701.4**	**1684.7**	**1680.9**	**1820.6**	**1787.8**	**1779.4**	**2043.8**	**2004.5**	**1933.9**
Electric Generators[6]										
Petroleum	20.0	9.1	6.3	6.2	5.3	3.1	3.4	4.8	2.6	2.4
Natural Gas	45.8	79.8	83.8	83.3	100.2	110.4	113.7	163.6	177.1	186.4
Coal	490.5	554.2	533.6	533.3	585.3	544.3	534.2	604.7	557.6	478.9
Total	**556.3**	**643.1**	**623.7**	**622.8**	**690.7**	**657.8**	**651.3**	**773.1**	**737.3**	**667.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	701.1	700.5	698.0	752.6	751.8	750.7	856.5	855.7	854.8
Natural Gas	311.8	377.5	381.8	381.0	414.0	424.7	427.2	513.6	526.2	535.8
Coal	549.3	622.7	602.3	601.7	653.8	611.2	601.4	673.5	622.5	543.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1701.4**	**1684.7**	**1680.9**	**1820.6**	**1787.8**	**1779.4**	**2043.8**	**2004.5**	**1933.9**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.8**	**5.8**	**6.1**	**6.0**	**5.9**	**6.3**	**6.2**	**5.9**

[1]Includes consumption by cogenerators.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel which, by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 1998, international bunker fuels accounted for 25 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
CO_2 = Carbon dioxide.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Sources: 1999 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99), (Washington, DC, October 2000). **Projections:** EIA, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.

Table D14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap	Reference	75 Percent	75 Percent with CO_2 Cap
Emissions										
Nitrogen Oxides (million tons)	5.43	4.30	4.18	4.18	4.34	2.34	2.41	4.48	1.64	1.42
Sulfur Dioxide (million tons)	13.49	10.39	7.98	7.98	9.70	5.51	5.51	8.95	2.24	2.24
Mercury (tons)	43.35	45.02	35.30	35.30	45.53	17.20	17.20	45.23	10.80	10.80
Carbon Dioxide										
(million metric tons carbon equivalent)	556.3	643.1	623.7	622.8	690.7	657.8	651.3	773.1	737.3	667.7
Allowance Prices										
Nitrogen Oxides (1999 dollars per ton)										
Summer Seasonal	0	4370	0	0	4404	0	0	5087	0	0
National Annual	0	0	1190	1180	0	2072	1891	0	2825	432
Sulfur Dioxide (1999 dollars per ton)	0	184	376	323	180	296	195	200	1737	2812
Mercury (million 1999 dollars per ton)	0	0	60	58	0	64	69	0	170	98
Carbon Dioxide										
(1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	33
Retrofits (gigawatts, cumulative from 1999)										
Scrubber [1]	0.0	8.9	19.4	23.8	8.9	61.7	66.2	17.5	151.5	115.2
Combustion	0.0	40.4	35.0	34.4	42.5	51.4	52.7	46.6	65.6	63.7
SCR Post-combustion	0.0	90.8	6.3	6.2	90.9	141.7	136.5	91.1	218.1	211.4
SNCR Post-combustion	0.0	28.5	0.8	0.8	28.5	10.3	10.5	46.0	43.8	45.3
Mercury Spray Cooler	0.0	0.0	0.0	0.0	0.0	11.9	1.6	0.0	29.3	18.8
Mercury Fabric Filter	0.0	0.0	0.0	0.0	0.0	57.7	58.1	0.0	66.9	65.1
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	473	582	601	583	633	568	536	714	627	517
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433	456	420	427	465	427	427	442	422	391
High Sulfur (> 1.67 lbs. S/mmBtu)	196	190	167	175	191	194	200	180	160	151

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
CO_2 = Carbon dioxide.
lbs. S/mmBtu = Pounds sulfur per million British thermal units.
Note: Totals may not equal sum of components due to independent rounding. Data for 1999 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2001 National Energy Modeling System runs SCENABS.D080301A, RENC7512.D081701B, REWC7512.D081701B.