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

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Energy Information Administration
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U.S. Department of Energy
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Contacts

This report was prepared by the Office of Integrated Analysis and Forecasting, Energy Information Administration. General questions concerning the report may be directed to Mary J. Hutzler (202/586-2222, mhutzler@eia.doe.gov), Director of the Office of Integrated Analysis and Forecasting, Scott B. Sitzer (202/586-2308, ssitzer@eia.doe.gov), Director of the Coal and Electric Power Division of the Office of Integrated Analysis and Forecasting, and Andy S. Kydes, Senior Adviser to the Director, Office of Integrated Analysis and Forecasting (akydes@eia.doe.gov, 202/586-2222). Specific questions about the report may be directed to the following analysts:

Electricity

J. Alan Beamon	202/586-2025	jbeamon@eia.doe.gov
Jeff Jones	202/586-2038	jjones@eia.doe.gov
Laura Martin	202/586-1494	laura.martin@eia.doe.gov

Renewables

Tom Petersik	202/586-6582	tpetersi@eia.doe.gov
Zia Haq	202/586-2869	zia.haq@eia.doe.gov
Christopher Namovicz	202/586-7120	cnamovicz@eia.doe.gov

Natural Gas

Joe Benneche	202/586-6132	jbennech@eia.doe.gov
Jim Lockhart	202/586-2854	james.lockhart@eia.doe.gov
Dana Van Wagener	202/586-4725	dana.van-wagener@hq.doe.gov

Coal

Mike Mellish	202/586-2136	mmellish@eia.doe.gov
Edward Flynn	202/586-5748	eflynn@eia.doe.gov
Diane Kearney	202/586-2415	diane.kearney@eia.doe.gov

Macroeconomic Impacts

Ron Earley	202/586-1398	rearley@eia.doe.gov

Comparisons

Tom Leckey	202/586-9413	tleckey@eia.doe.gov

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 current regulations. They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) 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 the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform[1] to examine the costs of such multi-emission reduction strategies (see Appendix A for the requesting letters). In its request the Subcommittee asked the Energy Information Administration (EIA) to "analyze the potential costs of various multi-pollutant strategies to reduce the air emissions from electric power plants." The Subcommittee requested that EIA examine the impacts of cases incorporating requirements for reductions of NO_x, SO_2, CO_2, and Hg emissions and for a renewable portfolio standard (RPS).

At the request of the Subcommittee, EIA prepared an initial report that focused on the impacts of reducing power sector NO_x, SO_2, and CO_2 emissions.[2] The current report extends the earlier analysis to add the impacts of reducing power sector Hg emissions and introducing RPS requirements.

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 submodules that represent the demand (residential, commercial, industrial, and transportation sectors), supply (coal, renewables, oil, and natural gas supply and natural gas transmission and distribution), and conversion (refinery and electricity sectors) of energy, together with a macroeconomic module that links energy prices to economic activity, and a representation of international oil markets.

Chapter 1 of this report provides a brief introduction. Chapter 2 describes the analysis cases and methodology. Chapter 3 provides electricity market results, and Chapter 4 examines projections for coal, natural gas, and renewable fuels markets and for the U.S. macroeconomy. Chapter 5 compares the results of this analysis with those of other analyses. For those familiar with the earlier report, the background material in Chapter 1 and the basic modeling methodology in Chapter 2 relating to NO_x, SO_2, and CO_2 have only minor changes. As a result, those readers may wish to focus on the discussion of the modeling of Hg emissions and the RPS, which were not addressed in the first report.

Within 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. The reviewers provided comments on a draft version of the report, after an earlier meeting with EIA to discuss the methodology and preliminary results. 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:

Dallas Burtraw
Resources for the Future

Steve Clemmer
Union of Concerned Scientists

Deborah Donovan
Union of Concerned Scientists

Alex Farrell
Carnegie Mellon University

Howard Gruenspecht
Resources for the Future

Gordon Hester
Electric Power Research Institute

[1]In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

[2]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide,* SR / OIAF / 2005 (Washington, DC, December 2000).

Henry Lee
Harvard University

Karen Palmer
Resources for the Future

John Weyant
Energy Modeling Forum.

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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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Highlights

This analysis responds to a request from the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform[1] to examine the costs of power sector multi-emission reduction strategies (see Appendix A for the requesting letters). The Subcommittee asked the Energy Information Administration (EIA) to examine the impacts of imposing caps on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2), with and without a renewable portfolio standard (RPS). Specifically, the Subcommittee requested "that EIA analyze the cost implications—the likely impacts on both consumers and energy markets" of various multi-pollutant strategies. EIA's analysis examines the effects of each of the emission caps and the RPS, both alone and in various combinations.

The analysis was prepared using EIA's National Energy Modeling System (NEMS). The reference case incorporates the NO_x and SO_2 regulations established in the Clean Air Act Amendments of 1990 but does not include limitations on either Hg or CO_2 emissions. The key results—assuming a cap and trade system except where noted—are summarized below.[2]

Reducing Power Sector NO_x and SO_2 Emissions

- Reducing power sector NO_x and SO_2 emissions to 75 percent below their 1997 level is projected to lead to the installation of a large amount of pollution control equipment, with little change in fuel use for electricity generation.
- Power suppliers are projected to incur significant expenditures in order to comply with NO_x and SO_2 caps, but electricity prices are expected to be only slightly higher as a result—generally within 1 percent of the reference case level.

Reducing Power Sector Hg Emissions

- Reducing power sector Hg emissions to 90 percent below their 1997 level is also projected to lead to the installation of a large amount of pollution control equipment. A shift in fuel use from coal to natural gas (7 percent in 2020) is also projected, because some coal-fired plants would not be operated as intensively if their generating costs were higher.
- The cost and price impacts of reducing power sector Hg emissions are projected to be larger than those of reducing NO_x or SO_2 emissions, with national average electricity prices projected to be 3 to 4 percent above reference case levels, on average, between 2010 and 2020.
- Although research on the measurement and removal of power sector Hg emissions has been carried out in recent years, the factors that contribute to the emissions and the capabilities of the technologies available for reducing them are not fully understood. There is considerable uncertainty about the cost and performance of Hg removal technologies, because full-scale demonstrations have not been carried out. The actual costs and performance of the available technologies (and others yet to be tested) may turn out to be different from those assumed for this analysis. A sensitivity case is analyzed to examine the potential impacts of technological improvements, assuming substantial (but not infeasible, given ongoing research) performance improvements in Hg removal technology. The price impacts are similar to those for reducing NO_x and SO_2 emissions.
- When Hg emissions are assumed to be reduced by using a maximum achievable control technology (MACT) approach requiring 90 percent removal, rather than an emissions cap and trade system capping Hg emissions at 90 percent below the 1997 level, the projected Hg emissions total 8 tons annually, 3 tons above the total in the cap and trade case. Electricity prices, while higher than in the reference case, are somewhat lower than in the cap and trade case.

[1]In the 107th Congress this Subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

[2]All the results presented in this report are based on the assumption that electric power generators must meet the specified emissions caps fully, without trading with other domestic sectors or internationally and without credits for offsets, such as reductions in other greenhouse gas emissions or changes in forestry practices. Allowing trading with other sectors and offset credits could produce different results.

Reducing Power Sector CO_2 Emissions

- When a cap on power sector CO_2 emissions is assumed, it is projected to have significant impacts on all aspects of the electricity production business. The key CO_2 compliance strategy is expected to be retirement of coal-fired capacity in favor of natural gas and, to a lesser extent, renewables, as well as the continued operation of more existing nuclear power plants.[3] Consumers are also expected to reduce their use of electricity in response to higher electricity prices.

- The electricity price impacts of meeting a CO_2 cap are much larger than those of meeting NO_x, SO_2, or Hg caps. When a cap on power sector CO_2 emissions at 7 percent below the 1990 level is assumed, average retail electricity prices are projected to be 43 percent above reference case levels in 2010.

Establishing a 20-Percent RPS

- A requirement that 10 percent of all power sales must come from nonhydroelectric renewable fuels by 2010 and 20 percent by 2020 is projected to cause power suppliers to slow the expected increase in their use of natural gas and, to a lesser extent, coal.

- Biomass, wind, and geothermal resources are projected to provide most of the required increase in renewable generation.

- The imposition of the RPS is projected to lead to slight reductions in power sector NO_x, SO_2, and Hg emissions and a larger reduction in CO_2 emissions. CO_2 emissions in 2020 are projected to be 18 percent lower when a 20-percent RPS is assumed than in the reference case forecast—still 35 percent above the 1990 level.

- The renewable credit price, or subsidy for nonhydroelectric renewables, is projected be between 4 and 5 cents per kilowatthour. The development of renewable generating facilities to comply with a 20-percent RPS is projected to lead to a 4-percent increase in electricity prices by 2020 relative to the reference case, because of the need to deploy higher cost renewable resources to meet the target.

- Lower use of natural gas in the electricity sector when a 20-percent RPS is assumed is projected to cause average wellhead prices for natural gas to be 7 percent lower in 2010 and 17 percent lower in 2020 than projected in the reference case.

Reducing Power Sector NO_x, SO_2, CO_2, and Hg Emissions

- The projected impacts of a power sector cap on CO_2 emissions dominate those of caps on other emissions. The key compliance strategy is a shift from coal to natural gas and, to a lesser extent, renewables, requiring costly capital additions. Consumers are also expected to reduce their use of electricity in response to higher electricity prices.

- Higher natural gas prices and CO_2 allowance prices for electricity producers are projected to result in higher electricity prices for consumers—37 percent higher than projected in the reference case in 2010—when NO_x, SO_2, and Hg emissions caps are imposed together with a CO_2 emissions cap set to 7 percent below the 1990 level.

- When the reference case technology assumptions for natural gas discovery and production are replaced with assumptions of less robust technology development, the projected price of electricity in 2020 with combined NO_x, SO_2, Hg, and CO_2 emission caps is 8 percent above the projection based on reference case natural gas technology assumptions.

- The price impacts of the emission caps are sensitive to assumptions about how electricity will be priced in the future and the policy instrument used to reduce emissions. If suppliers do not pass on the opportunity costs of CO_2 allowances in regulated regions, the price impacts of imposing the emission caps could be smaller—25 percent higher than the reference case level in 2010 rather than 37 percent higher; however, because consumers would have less incentive to conserve and power suppliers would need to develop renewable fuel facilities to meet the higher level of demand, the compliance costs for power suppliers are projected to be higher. Similarly, an earlier analysis showed that if emissions allowances were allocated using a dynamic generation performance standard, the price impacts would be lower but the impacts on resource costs would be higher.[4]

[3]At the request of the Subcommittee, it was assumed that no new nuclear units would be constructed.

[4]See J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/gpsstudy.html.

Reducing Power Sector NO_x, SO_2, CO_2, and Hg Emissions With an RPS

- Combining a 20-percent RPS requirement in 2020 with caps on NO_x, SO_2, Hg, and CO_2 emissions is projected to reduce the shift to natural gas as a fuel for electricity generation and increase the use of renewable fuels. The renewable credit price, or subsidy for nonhydroelectric renewables, is projected to be approximately 3 cents per kilowatthour.

- The switch to renewables instead of natural gas is expected to lead to lower natural gas prices than would otherwise be expected. For example, when power sector caps on NO_x, SO_2, Hg, and CO_2 emissions (at 7 percent below the 1990 level) are combined, the projected wellhead price of natural gas in 2020 is 16 percent higher than projected in the reference case; but when a 20-percent RPS by 2020 is also assumed, the projected wellhead natural gas price in 2020 is only 3 percent higher than in the reference case. The lower natural gas price would benefit both electricity consumers and natural gas users in other sectors of the economy.

- The addition of the RPS to caps on NO_x, SO_2, CO_2, and Hg emissions is projected to increase the resource costs of compliance faced by power suppliers by $21 billion over the 2000 to 2020 time period from what it would be without the RPS requirement. In 2010, electricity prices are projected to be 40 percent above the reference case level when a 20-percent RPS is combined with caps on NO_x, SO_2, Hg, and CO_2 (at 7 percent below the 1990 level), as compared with 37 percent when the RPS is not included. However, because the RPS leads to lower natural gas prices and, in turn, lower CO_2 allowance prices, electricity prices are projected to be lower in 2020 when the RPS is included than when it is not.

Uncertainties

- The changes required to comply with the power sector emission caps analyzed in this report, especially the caps on CO_2 emissions, are projected to cause significant shifts in the generating capacity and fuels used to produce electricity. There is substantial uncertainty about how the various fuel markets—for coal, natural gas, and renewables—might respond to the projected changes, as well as the degree to which consumers might respond to the projected increases in electricity prices. History does not offer clear guidance as to how the various markets might respond to changes as large as those required by the proposed emissions targets.

- As with any 20-year projection, the role that new technologies might play is uncertain. Although this analysis incorporates assumed improvements in technology costs and performance over time, the true evolution of new technological development is unpredictable. Costs and performance could be lower or higher than those assumed in this analysis, particularly for technologies that reduce Hg and for renewable energy technologies.

Executive Summary

Background

This analysis responds to a request from the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform[1] to examine the costs of power sector multi-emission reduction strategies (see Appendix A for the requesting letters). The Subcommittee asked the Energy Information Administration (EIA) to examine the impacts of imposing caps on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2), with and without a renewable portfolio standard (RPS).[2] Specifically, the Subcommittee requested "that EIA analyze the cost implications—the likely impacts on both consumers and energy markets" of various multi-pollutant strategies.

At the request of the Subcommittee, an initial analysis of emissions caps on NO_x, SO_2, and CO_2 was released in December 2000.[3] The current report extends the earlier analysis to add the impacts of reducing power sector Hg emissions and introducing RPS requirements. This report also incorporates the impacts of the higher natural gas prices seen in 2000 and early 2001. The emission caps on NO_x and SO_2 analyzed in this report are assumed to be phased in over the 2002 to 2008 time period. When the 1990-7% cap on CO_2 emissions is incorporated, it is assumed to be achieved over the 2008 to 2012 time period. The cap on Hg emissions is assumed to be fully effective in 2008.

Analysis Approach

The analysis in this report was prepared using the National Energy Modeling System (NEMS). NEMS simulates the energy investment and utilization decisions of the various sectors of the U.S. economy—i.e., households, commercial establishments, industrial facilities, and energy suppliers. When power sector emission caps are imposed, NEMS simulates the decision process in each economic sector to determine an appropriate compliance strategy. Unless otherwise specified, each of the emission caps imposed is assumed to be implemented under a "cap and trade" system patterned after the SO_2 allowance program created in the Clean Air Act Amendments of 1990 (CAAA90).[4] All electricity generators, excluding cogenerators, are assumed to be covered by the emissions caps. Electricity generators are assumed to behave competitively, incorporating the costs of emissions allowances in their electricity bid prices.[5] Because of the uncertainty inherent in any forecast, sensitivity cases are used to illustrate the importance of key assumptions in the analysis; however, numerous uncertainties remain, as discussed at the end of this Executive Summary.

Electricity Market Impacts

Reference Case

Over the next 20 years coal is expected to remain the most important fuel for electricity generation (Figure ES1). Its share of generation is expected to decline, however, because natural-gas-fired generating plants are expected to account for more than 90 percent of new power plant additions. The reference case for this analysis incorporates the CAAA90 NO_x and SO_2 regulations but does not include limitations on either Hg or CO_2 emissions.

After declining in 2000 and 2004 in response to current regulatory actions, NO_x emissions in the reference case are expected to rise slowly through 2020 (Figure ES2), but they are expected to remain below the 2000 level in 2020.

SO_2 emissions are also expected to decline as the second phase of the CAAA90 SO_2 allowance program takes

[1]In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

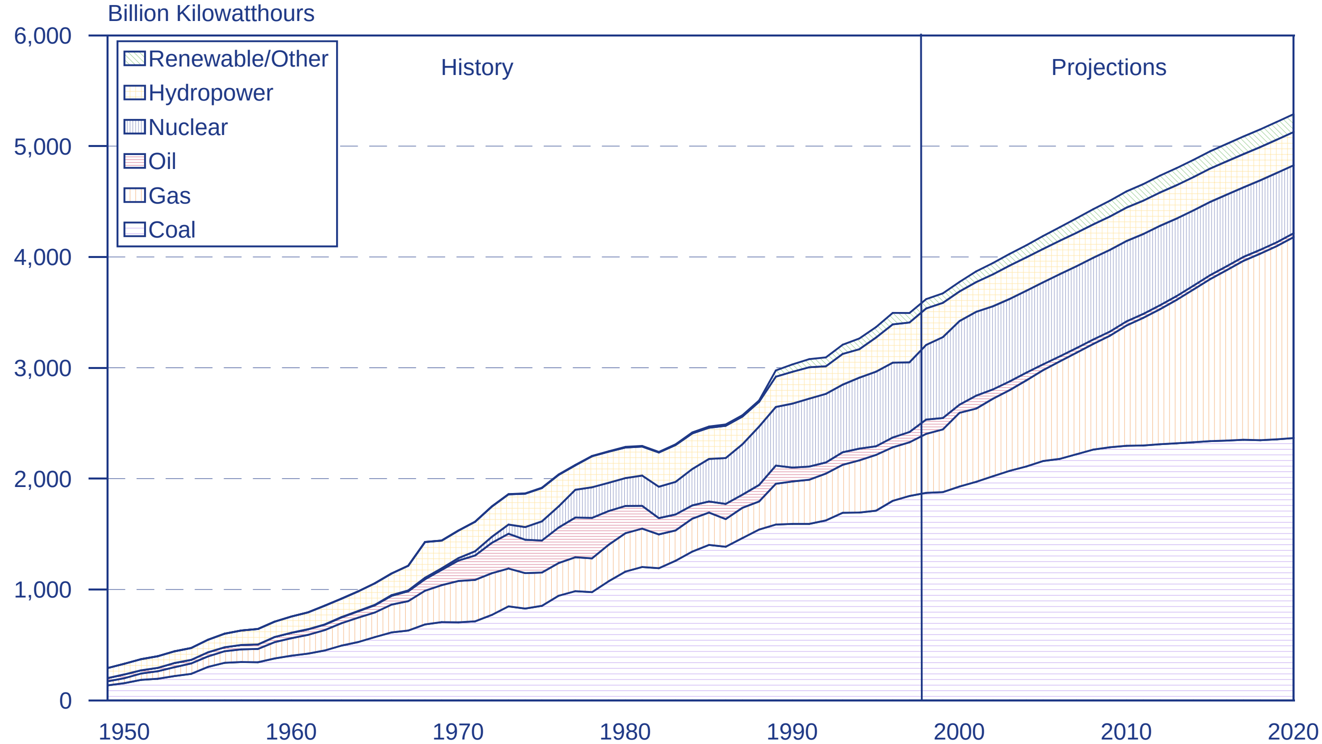
[2]A renewable portfolio standard (RPS) requires that qualifying renewable facilities generate a specified share of power sold. Qualifying renewable generators are issued credits for each kilowatthour they generate, which they can keep for their own use or sell to others who need them to meet the RPS requirement.

[3]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Nitrogen Oxides, Sulfur Dioxide, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000).

[4]The reader should be aware that numerous policy instruments—e.g., taxes, Maximum Achivable Control technology (MACT), no-cost allowance allocation with cap and trade, allowance auction with cap and trade, Generation Performance Standard (GPS) allowance allocation with cap and trade—are available. Each of the options would have different price and cost impacts.

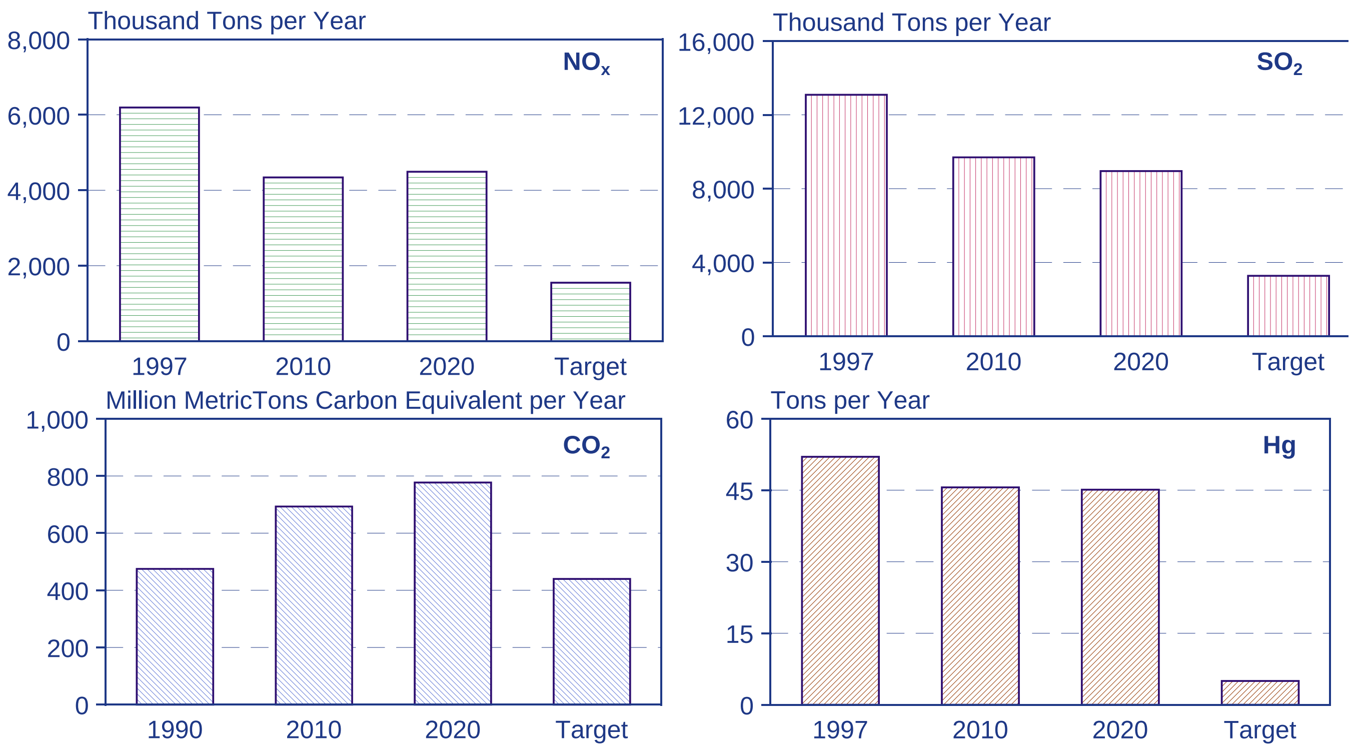
[5]One case prepared for this analysis assumed that emissions allowances would be treated as having zero value in regions where electricity prices continue to be based on cost of service rather than competitive pricing.

Figure ES1. 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 M2BASE.D060801A.

Figure ES2. Historical Emissions, Reference Case Projections for 2010 and 2020, and Target Caps for Electricity Generators, Excluding Cogenerators



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

effect. Because power companies have accumulated (banked) allowances for later use, the 8.95 million ton SO_2 emission cap is not expected to be reached until well after the 2000 compliance date. Once the cap is reached, SO_2 emissions are expected to remain at that level through 2020.

Power sector Hg emissions are expected to remain fairly steady in the reference case over the next 20 years, at about 45 tons per year. Although coal use is expected to grow, the projected switch to lower sulfur—and lower Hg—coal and the addition of equipment to reduce SO_2 emissions reduces the increase in Hg emissions that might otherwise be expected.

Power sector CO_2 emissions are expected to increase steadily through 2020. The increased use of existing coal-fired power plants, the addition of a small number of new coal-fired plants, and growing dependence on natural gas to meet growth in the demand for electricity are the key factors in the increase.

Reducing NO_x and SO_2 Emissions

When it is assumed that NO_x and SO_2 emissions must be capped at 75 percent below their 1997 levels by 2008, power suppliers are projected to add emissions control equipment to meet the caps—scrubbers to reduce SO_2 emissions and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) equipment to reduce NO_x emissions. They are also expected to shift toward lower sulfur coal to reduce SO_2. The mix of fuels used to generate electricity is expected to change very little from the reference case, with only a small shift from coal-fired to natural-gas-fired generation.

Although scrubbers, SNCRs, and SCRs can be expensive, they generally are not costly enough to make existing coal-fired plants uneconomical. Adding both NO_x and SO_2 control equipment would likely cost between $150 to $250 per kilowatt of generating capacity, as compared with the $500 to $1,000 per kilowatt that a new plant might cost. As a result, the average national price impacts of reducing NO_x and SO_2 are expected to be small, generally within 1 percent of the projections without the more stringent emission caps. The addition of SO_2 control equipment to meet the lower SO_2 cap also leads to a reduction in Hg emissions—lowering the annual total in 2020 by 13 tons (28 percent) from the level expected without the more stringent SO_2 cap.

Reducing Hg Emissions

As in the case of NO_x and SO_2 emissions, the key compliance strategy for reducing Hg emissions is projected to be the addition of emissions control equipment. The technology represented in this analysis is the use of activated carbon injection (ACI) with and without spray cooling and / or a supplemental fabric filter. This technology has been demonstrated in pilot-scale tests; however, there is substantial uncertainty about the ultimate cost and performance characteristics of ACI, because full-scale tests of the technology at high removal levels have not been completed. Other technologies, including advanced coal washing approaches, the use of alternative absorbents, systems to recycle activated carbon for repeated use, and systems to control NO_x, SO_2, and Hg emissions together, are in various stages of research and development. In addition, there is uncertainty about the role that SCRs may play in reducing Hg emissions. Although it is possible that some of these technologies will prove economical, it may be difficult or nearly impossible to remove 90 percent of the Hg from certain coal types in some power plant configurations.

When it is assumed that power suppliers must meet a 5-ton national cap (90 percent below the 1997 level) on annual Hg emissions by 2008, they are projected to switch to lower Hg coal, add scrubbers that reduce both SO_2 and Hg emissions, and add ACI equipment. In addition, electricity producers are expected to reduce their use of coal slightly and increase their use of natural gas. The average Hg content of coal used for electricity generation is projected to fall by 15 percent between 2000 and 2020 as generators reduce their emissions to meet the targets, assuming that a cap and trade program is implemented for controlling Hg emissions. They are also projected to add scrubbers to 52 gigawatts of capacity to reduce Hg and SO_2 emissions, as compared with about 15 gigawatts when the CAAA90 SO_2 cap (8.95 million tons per year) is assumed. The additional scrubbers are projected to reduce SO_2 emissions to 19 percent below the CAAA90 cap. Power suppliers are also projected to add ACI equipment to the vast majority of coal-fired plants and to reduce their overall coal-fired generation by 7 percent in 2010 and 2020 to meet the 5-ton Hg cap.

The actions needed to meet a 5-ton Hg emission cap are projected to have a larger price impact than those needed to meet the NO_x and SO_2 emission caps (Figure ES3). In this case, electricity prices are projected to be between 3 and 4 percent higher in 2010 and 2020. The price increases expected to result from the 5-ton Hg cap are projected to increase the Nation's total electricity bill by $8.4 billion in 2010 and $6.1 billion in 2020 relative to the reference case projections. When a less stringent 20-ton Hg cap is assumed, the electricity price impact is projected to be similar to that for controlling NO_x or SO_2 emissions, generally within 1 to 2 percent of the price expected without a cap. Similarly, if engineers are successful in developing more economical Hg control systems, such as ACI systems that allow large-scale recycling of activated carbon, the electricity price impact of meeting a 5-ton cap is also projected to be within 1 to 2 percent of the price expected without a cap.[6]

One important question with respect to reducing Hg emissions is whether they would be controlled with a cap and trade program, or whether maximum achievable control technology (MACT) standards would be set for each plant type. Because Hg is classified as a hazardous air pollutant (HAP), a MACT approach may be implemented. A cap and trade program would give power suppliers flexibility to reduce emissions at the lowest possible cost, but reductions under such an approach may not be uniform across the country.

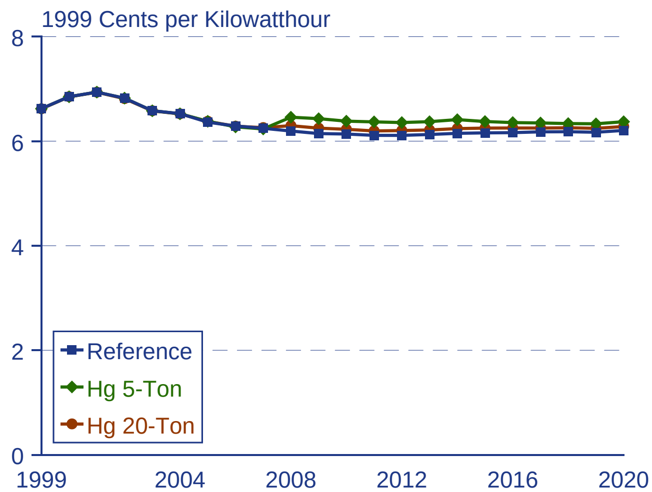
In an analysis assuming that all coal-fired power plants would be required to reduce the Hg in the coal they use by 90 percent, the results generally are similar to those of the 5-ton cap and trade case; however, there are several key differences. First, requiring all plants to reduce the amount of Hg in the coal they use by 90 percent would not achieve a 90-percent reduction in overall Hg emissions. Because the coal used annually in power plants is estimated to contain roughly 74 tons of Hg, a 5-ton cap actually represents a 93-percent reduction from the Hg content of the coal. Thus, a 90-percent MACT would force Hg emissions to 7.4 tons if there were no change in coal use. However, because coal use is expected to increase, Hg emissions in a 90-percent MACT case are expected to exceed this level. Projected power sector Hg emissions in 2020 when a 90-percent MACT standard is assumed are just over 8 tons—a reduction of approximately 84 percent from the 1997 level and more than 3 tons (60 percent) above the emission target assumed in the 5-ton cap and trade case.

The electricity price impacts under a MACT approach are projected to be lower than under a cap and trade system, because no Hg allowance prices would be reflected in power plant operating costs,[7] and the effective limit on Hg emissions would not be as stringent. The projections for regional Hg emissions in 2020 under the two regulatory approaches show only slight variations (Figure ES4). The results suggest that if large reductions—on the order of 90 percent—are required under either regulatory approach, there is likely to be little opportunity for overcompliance in some areas and undercompliance in others. In the Hg 20-ton case, however, the burden of reducing emissions is not projected to be spread as evenly, with the percentage reduction in most regions ranging from 47 to 75 percent in 2010.

Reducing CO_2 Emissions

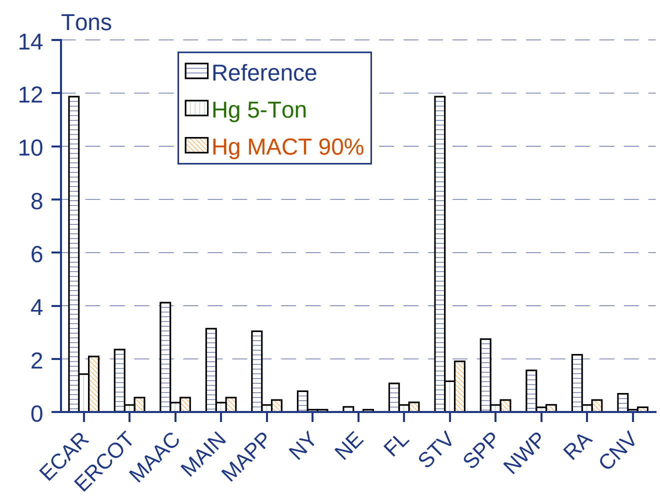
Unlike for NO_x, SO_2, and Hg, the primary compliance strategy for an assumed reduction in power sector CO_2 emissions to 7 percent below their 1990 level is projected to be a major shift in the fuels used to produce electricity (Figure ES5). To reduce CO_2 emissions, power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce their use of electricity in response to

Figure ES3. Projected Electricity Prices in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M6008.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES4. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg MACT 90% Cases, 2010

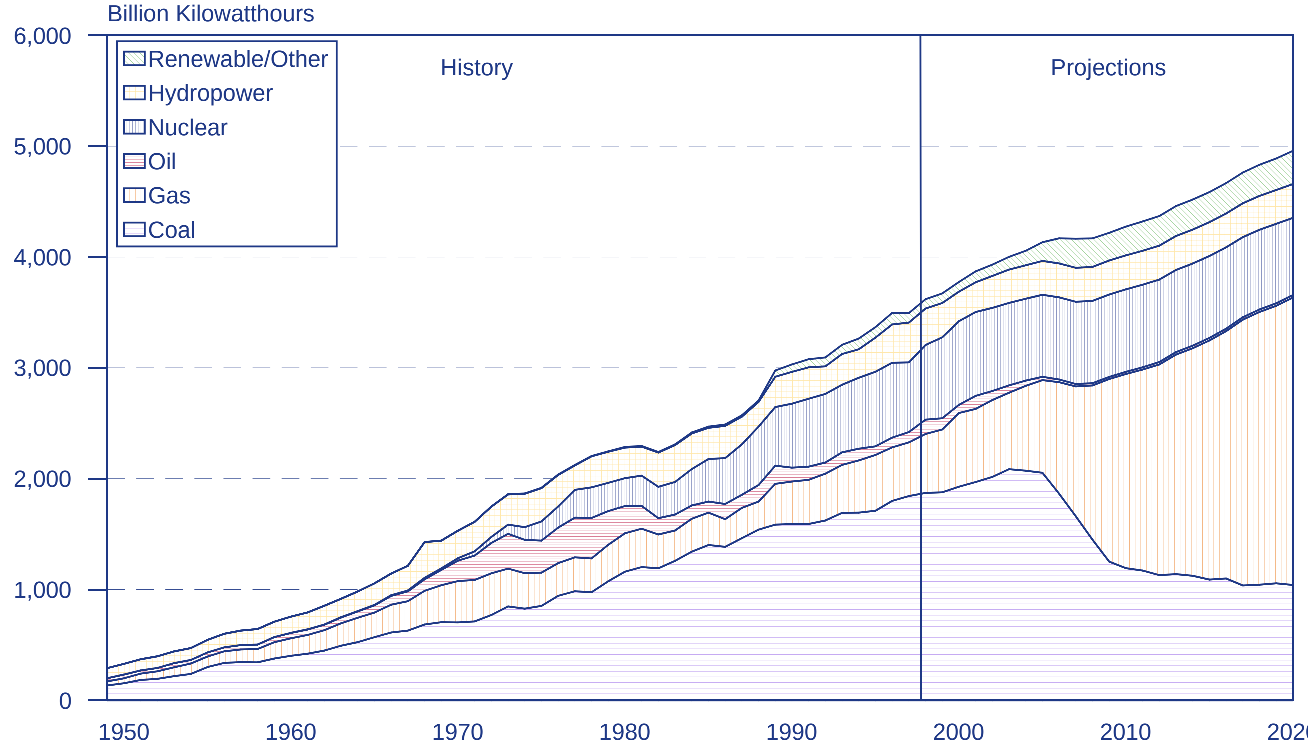


Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M9008M.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions. See Figure 26 in Chapter 4 for a map of electricity supply regions.

[6]The ACI recycling technology is meant to be representative of several Hg removal technologies that are now in various stages of development. It is impossible to predict at this time which technology might prove to be the most economical.

[7]Although coal-fired plants usually do not set market clearing prices, they do set them in some regions during periods of relatively low demand.

Figure ES5. Electricity Generation by Fuel, 1949-1999, and Projections for the CO_2 1990-7% 2008 Case, 2000-2020



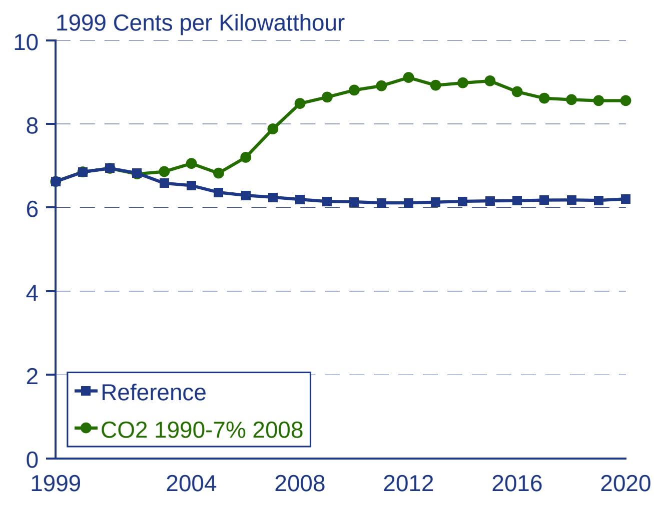
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run M2C7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

higher electricity prices, and cogeneration capacity is expected to grow to avoid higher grid-based electricity prices. In the later years of the projections, technologies for the capture and storage of carbon from fossil-fired power plants may emerge, but they are not expected to be economical in the time frame of this analysis.

Coal-fired electricity generation is projected to be 48 percent lower in 2010 and 56 percent lower than in the reference case in 2020 when a CO_2 cap at 7 percent below the 1990 level is assumed. Conversely, natural-gas-fired generation is projected to be 61 percent higher in 2010 and 43 percent higher in 2020. Similarly, renewable generation is expected to be 27 percent higher in 2010 and 32 percent higher in 2020. In addition, because nuclear capacity retirements are expected to be 14 gigawatts lower, electricity generation from nuclear power plants is expected to be 3 percent higher in 2010 and 14 percent higher in 2020 than projected in the reference case.

As a result of higher natural gas prices and the costs of CO_2 allowances purchased by power producers, electricity prices are projected to be much higher when CO_2 emissions are capped than when NO_x, SO_2, or Hg emissions are capped—43 percent higher in 2010 and 38 percent higher in 2020 than projected in the reference case (Figure ES6). Consumers are expected to reduce their electricity consumption by 8 percent in 2010 and 12 percent in 2020 when faced with higher electricity prices.

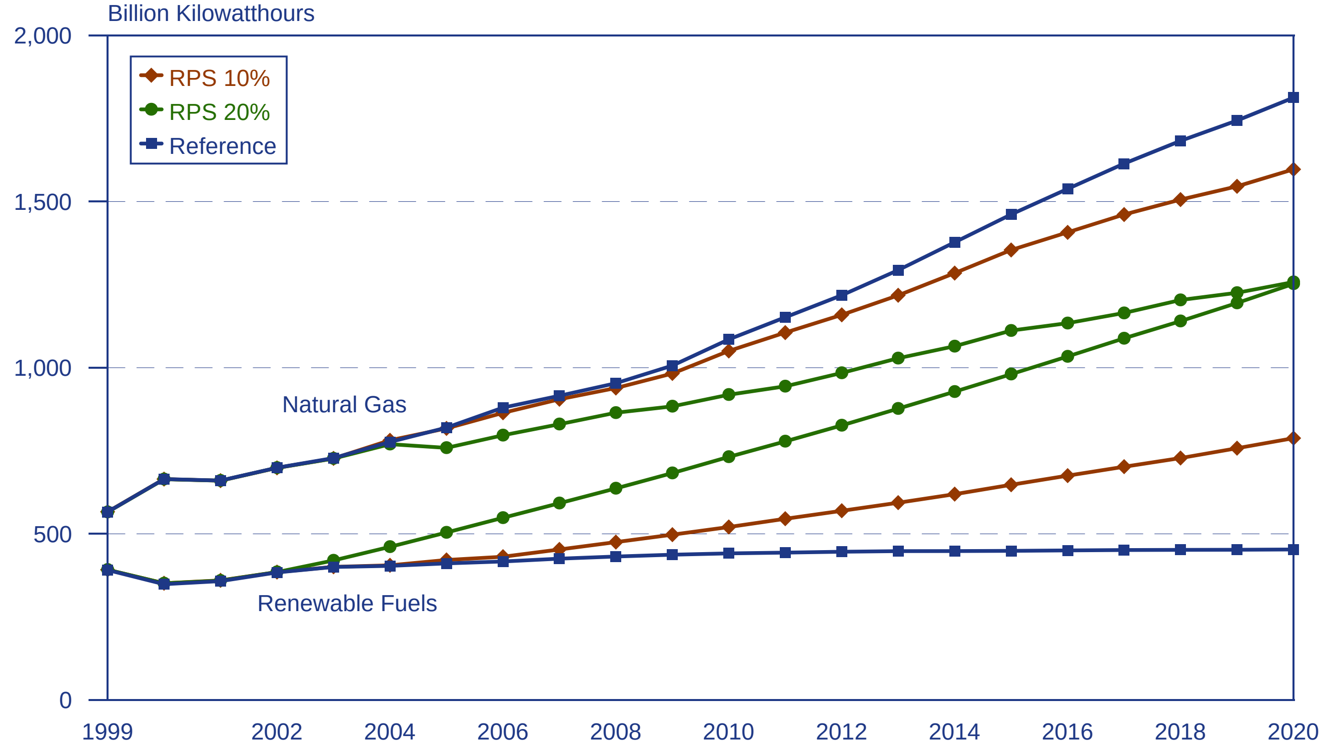
Figure ES6. Projected Electricity Prices in the Reference and CO_2 1990-7% 2008 Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

For the average household, annual electricity bills are projected to be $218 (23 percent) higher in 2010 and $173 (17 percent) higher in 2020 than in the reference case. Consequently, the Nation's total electricity bill is projected to be $80 billion higher in 2010 and $63 billion higher in 2020.

Figure ES7. Projected Electricity Generation from Natural Gas and Renewable Fuels in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Note: Conventional hydroelectric generation, included in the projections shown in this figure, does not qualify under the RPS.

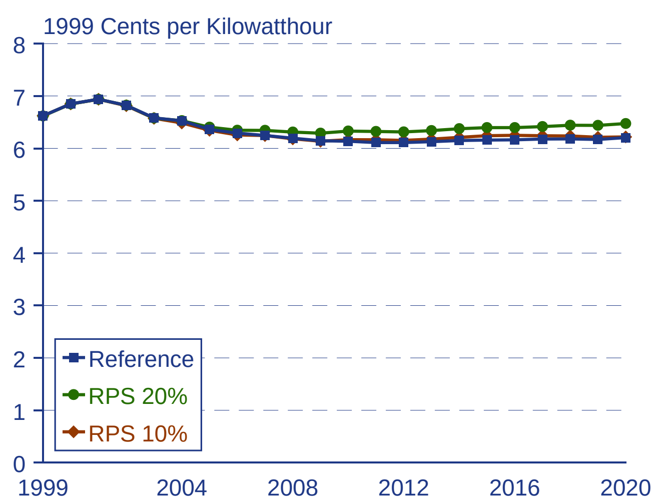
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Implementing a Renewable Portfolio Standard

When it is assumed that 20 percent of electricity sales must be produced from nonhydroelectric renewable fuels over the next 20 years, electricity generation from renewable fuels is projected to increase at the expense of growth in natural gas and, to a lesser extent, coal use (Figure ES7). The key renewables expected to benefit from an RPS are biomass (co-fired in coal plants and dedicated plants) and wind. The development of the large amount of renewables needed to satisfy the RPS is projected to lead to higher electricity prices. To reach the assumed target of 20 percent of electricity sales generated from nonhydroelectric renewable sources by 2020, developers are expected to turn increasingly to more expensive renewable options. As a result, the renewable credit price—the subsidy needed to make the new nonhydroelectric renewable plants competitive with other generating options—is projected to be between 4 and 5 cents per kilowatthour between 2010 and 2020, in order to provide sufficient incentive for the electric power industry to build new renewable capacity rather than less expensive natural-gas-fired capacity.

The impact on electricity prices is much smaller than the renewable credit prices. Because each seller of electricity must hold renewable credits equal only to the required RPS share of renewables (i.e., 10 percent of sales in 2010 and 20 percent in 2020), the price of electricity when a 20-percent RPS is imposed is projected to be 3.3 percent higher in 2010 and 4.3 percent higher in 2020 than in the reference case (Figure ES8). However, the impact of the RPS on electricity prices is sensitive to the required RPS share. For example, when a 10-percent RPS by 2020 is

Figure ES8. Projected Electricity Prices in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

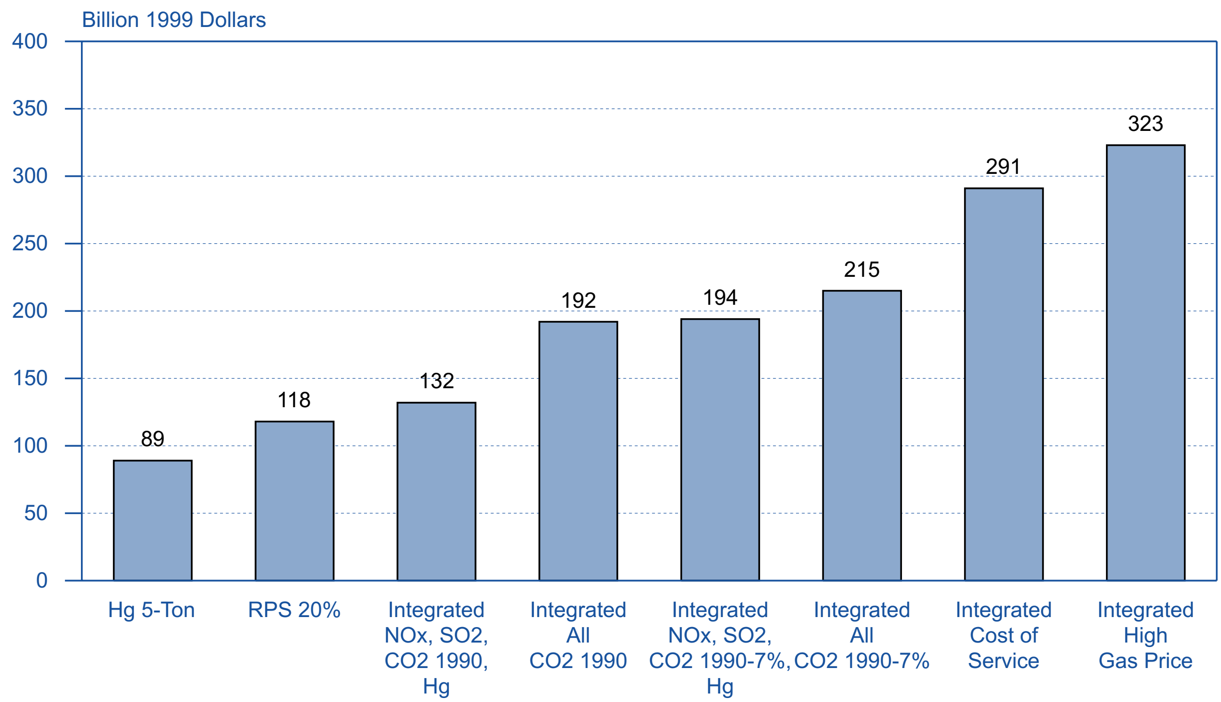
assumed, electricity prices are projected to be 0.5 percent higher in 2010 and 0.2 percent higher in 2020 than projected in the reference case—a much smaller increase than when a 20-percent RPS by 2020 is assumed.

Reducing Power Sector NO_x, SO_2, CO_2, and Hg Emissions Together, With and Without an RPS

When emission caps on NO_x, SO_2, CO_2, and Hg are assumed in various combinations, with and without an RPS, there are complex interactions among the compliance strategies and the resulting prices of emission allowances and electricity prices. The interactions can cause the impacts on resource costs and the impacts on electricity prices to move in opposite directions. For example, although resource costs are projected to be higher when caps are placed on all four emissions than when they are placed only on NO_x, SO_2, and CO_2, electricity prices are projected to be slightly lower. This occurs because the addition of an Hg cap raises the cost of continuing to operate existing coal-fired plants, leading to a reduction in the CO_2 allowance price that would be required to encourage power suppliers to retire coal-fired power plants and replace them with natural-gas-fired plants. Because the CO_2 allowance price would be included in the operating costs for all generating plants that use fossil fuels, a lower CO_2 allowance price would reduce the revenues of power suppliers in the cases with four emissions caps by lowering the costs of operating fossil plants and, thus, would lead to lower electricity prices.

Similarly, when an RPS is assumed to be combined with caps on NO_x, SO_2, CO_2, and Hg emissions, resource costs for generators complying with the caps are projected to be higher than when the RPS is not included (Figure ES9). However, while electricity prices are projected to be well above reference case levels when NO_x, SO_2, CO_2, and Hg emissions are capped either with or without an RPS, they are projected to be lower in the long term when the RPS is included,[8] because increased dependence on renewables rather than natural gas would lead to lower prices for natural gas and for CO_2 allowances, offsetting the effects of the higher costs of renewable fuels on consumer electricity prices.[9] Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

Figure ES9. Cumulative Resource Costs for Electricity Production, 2001-2020: Differences from Reference Case Projection in Selected Cases



Source: National Energy Modeling System, runs M2BASE.D080401A, M2M9008.D080401A, M2P9008.D080401A, M2RPS20.D080401A, M2P9008R.D080401A, M2P7B08.D080401A, M2P7B08R.D080401A, M2P7B08L.D080401A, and M2P7B08C.D080401A.

[8]In the early years of the forecast, electricity prices are projected to be higher in the case that combines an RPS with caps on NO_x, SO_2, CO_2, and Hg emissions than in the case that includes only the four emission caps.

[9]Retail electricity prices are assumed to be determined competitively in regions where most of the States have passed legislation or issued regulatory orders to deregulate their electricity sectors. In other regions, retail electricity prices are assumed to continue to be based on cost of service pricing.

When power sector CO_2 emissions caps are assumed—whether at the 1990 level or 7 percent lower—the effects of compliance efforts far outweigh the steps that would be taken to comply with the other emission caps. As in the case of a CO_2 cap alone, the primary compliance strategy is expected to be a major shift in the fuel mix used to produce electricity (Table ES1). Power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce electricity use in response to higher electricity prices, and cogeneration capacity is expected to be expanded in response to higher grid-based electricity prices. The role of renewables is especially important when an RPS requirement is included (Figure ES10).

When CO_2 emissions are capped at the 1990 level, with or without other emission caps, coal-fired electricity generation in 2020 is projected to be approximately half the level projected in the reference case (Figure ES11), and the projected share of electricity generation from natural gas is much larger. When an RPS is included, the expected increase in renewable electricity generation dampens the increase in natural gas generation and slightly reduces the need to limit coal-fired generation. The addition of carbon-free renewables stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 cap. In contrast, when the cap on CO_2 emissions is tightened to 7 percent below the 1990 level, the projected reduction in coal-fired generation is even larger.

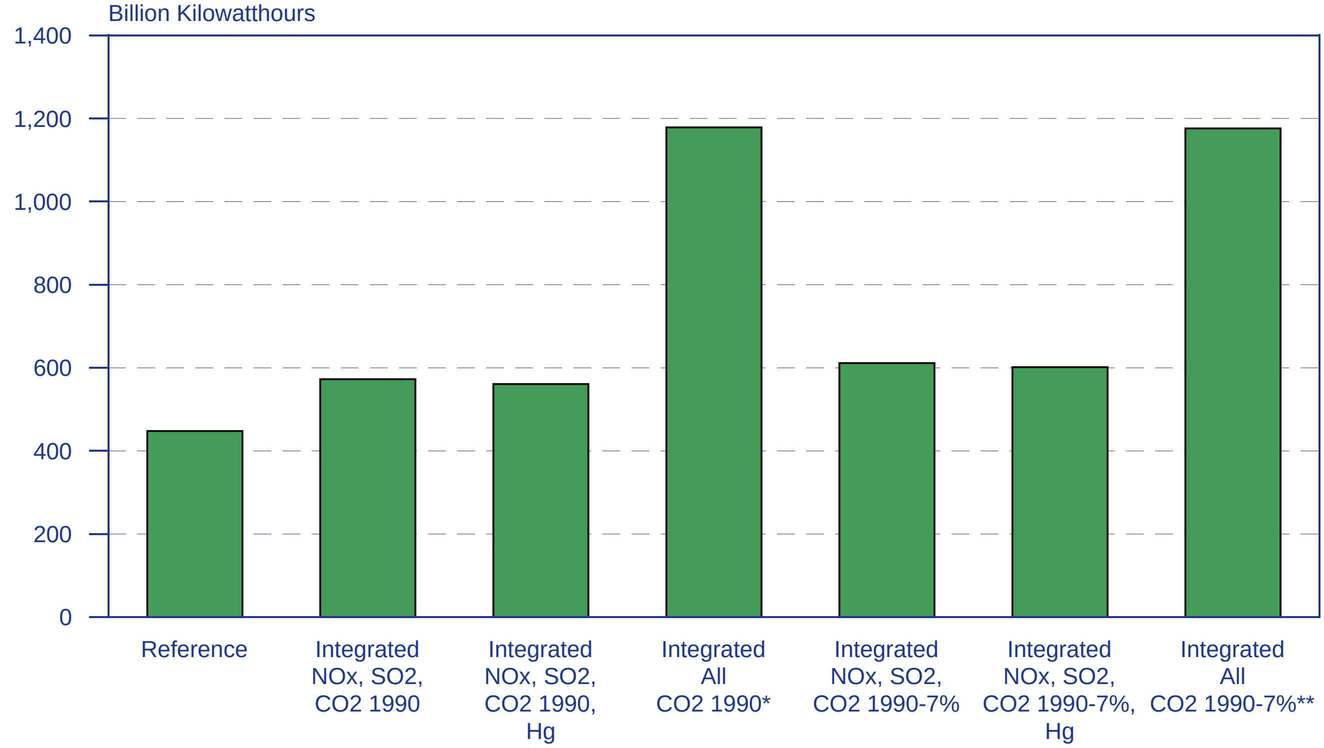
The combination of higher natural gas prices and CO_2 allowance prices is projected to lead to significant electricity price increases when a CO_2 cap is incorporated with other emission caps. As might be expected, when the CO_2 cap is set to 7 percent below the 1990 level, the

Table ES1. Key Results for the Electricity Generation Sector in Integrated Cases, 2010 and 2020

Analysis Case	Generation by Fuel (Billion Kilowatthours)			Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Electricity Price (1999 Cents per Kilowatt-hour)	Electricity Sales (Billion Kilowatt-hours)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenue (Billion 1999 Dollars)
	Coal	Natural Gas	Renewable Fuels					
2010								
Reference	2,297	1,085	436	2.87	6.14	4,147	944	255
Cases with CO_2 Emissions Capped at 1990 Level								
Integrated NO_x, SO_2, CO_2 1990	1,432	1,585	551	3.24	8.13	3,873	1,108	315
Integrated NO_x, SO_2, $CO_2$1990, Hg	1,333	1,734	523	3.40	7.92	3,896	1,090	308
Integrated All CO_2 1990[a]	1,471	1,344	762	2.97	8.01	3,882	1,097	311
Cases with CO_2 Emissions Capped at 1990-7% Level								
Integrated NO_x, SO_2, CO_2 1990-7%	1,189	1,780	551	3.50	8.62	3,830	1,152	330
Integrated NO_x, SO_2, $CO_2$1990-7%, Hg	1,113	1,889	542	3.66	8.42	3,851	1,136	324
Integrated All CO_2 1990-7%[b]	1,268	1,512	745	3.13	8.59	3,830	1,147	329
Integrated Sensitivity Cases								
Integrated Moderate Targets	1,539	1,456	572	3.09	8.18	3,870	1,109	316
Integrated Cost of Service	1,046	2,025	554	3.96	7.68	3,956	1,069	304
Integrated High Gas Price	1,124	1,838	553	4.08	8.60	3,838	1,152	330
2020								
Reference	2,366	1,813	448	3.22	6.21	4,788	1,005	297
Cases with CO_2 Emissions Capped at 1990 Level								
Integrated NO_x, SO_2, CO_2 1990	1,136	2,571	572	3.69	8.41	4,291	1,177	361
Integrated NO_x, SO_2, $CO_2$1990, Hg	1,124	2,584	561	3.72	8.36	4,309	1,172	360
Integrated All CO_2 1990[a]	1,390	1,784	1,178	3.09	7.82	4,354	1,127	340
Cases with CO_2 Emissions Capped at 1990-7% Level								
Integrated NO_x, SO_2, CO_2 1990-7%	1,013	2,605	611	3.80	8.63	4,218	1,185	364
Integrated NO_x, SO_2, $CO_2$1990-7%, Hg	1,032	2,608	602	3.74	8.55	4,257	1,182	364
Integrated All CO_2 1990-7%[b]	1,235	1,909	1,176	3.31	7.98	4,313	1,142	344
Integrated Sensitivity Cases								
Integrated Moderate Targets	1,413	2,138	755	3.74	8.19	4,318	1,158	354
Integrated Cost of Service	894	2,719	705	4.15	7.86	4,453	1,126	350
Integrated High Gas Price	1,082	2,098	735	5.05	9.27	4,188	1,237	388

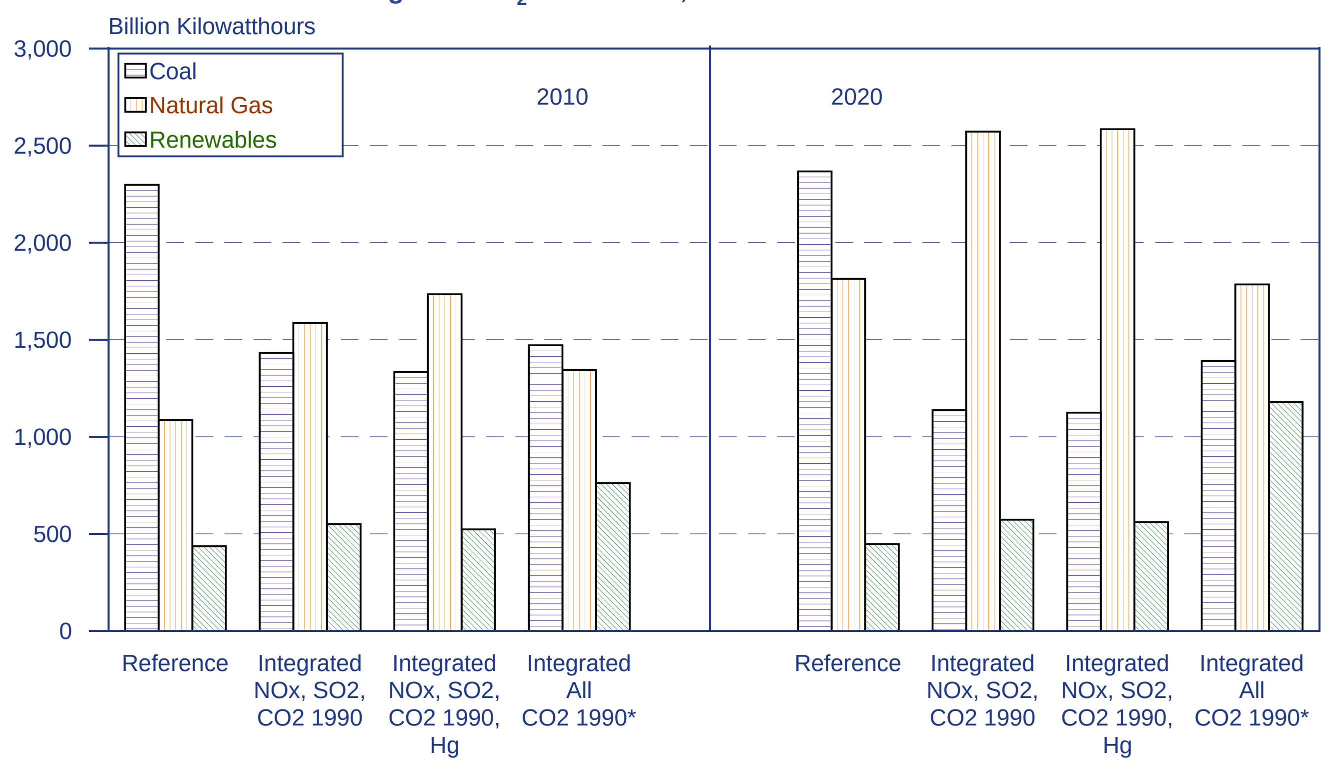
[a]Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
[b]Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES10. Projected Electricity Generation from Renewable Fuels in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



*Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
**Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.

Figure ES11. Projected Electricity Generation from Coal, Natural Gas, and Renewable Fuels in the Reference and Integrated CO_2 1990 Cases, 2010 and 2020



*Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, and M2P9008R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

projected impact on electricity prices is larger than when the CO_2 cap is set to the 1990 level (Figure ES12). For example, the price of electricity in 2010 is projected to be 7.92 cents per kilowatthour when NO_x, SO_2, and Hg caps are combined with a CO_2 cap set to the 1990 level, but 8.42 cents per kilowatthour when they are combined with a CO_2 cap set to 7 percent below the 1990 level—29 percent and 37 percent higher, respectively, than in the reference case. The higher electricity prices are projected to lead to increases of $146 and $192, respectively, in annual household electricity bills and $53 billion and $69 billion, respectively, in the Nation's total electricity bill.

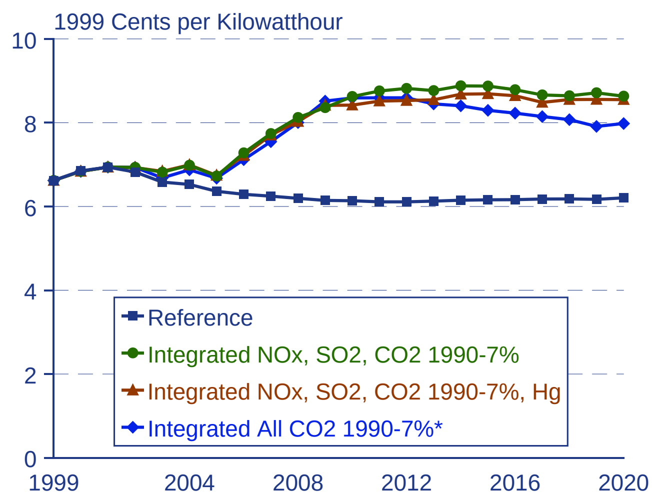
When an Hg emission cap is combined with caps on NO_x, SO_2, and CO_2 emissions, the impact on electricity prices is projected to be lower than when NO_x, SO_2, and CO_2 emissions caps are implemented without an Hg cap. As explained, the Hg reduction requirement increases the costs of continuing to operate coal-fired plants and reduces the CO_2 allowance price needed to stimulate power suppliers to turn from coal to natural gas and renewables. Because the CO_2 allowance price impacts all fossil fuel generators, when it is lower the costs of operating all fossil plants and the resulting electricity prices are also lower.

When an RPS is also included, the resource costs of compliance are projected to be $21 billion higher than they would be without he RPS. Electricity prices are projected to be higher in the early years of the forecast, when new renewable power plants are built rather than new natural-gas-fired plants. In the later years, however, the increased use of renewable fuels reduces natural gas consumption in the power sector, leading to a smaller projected increase in natural gas prices and lower CO_2 allowance prices and, in turn, a smaller increase in electricity prices.

Among the key assumptions that influence the projections when multiple emission caps are modeled are the levels of the emission caps, the approach used to price electricity, and the response of the natural gas market to increased demand from the electricity sector. For example, when less stringent caps on NO_x, SO_2, Hg, and CO_2 are assumed—requiring approximately half the reductions assumed in the more stringent scenarios—electricity prices in 2010 are projected to average 8.18 cents per kilowatthour, as compared with 8.59 cents per kilowatthour when the more stringent caps are assumed (Figure ES13).

Smaller increases in electricity prices are also projected when it is assumed that prices in many regions of the country will continue to be based on cost of service pricing. Regulators in those regions could treat any emissions allowances allocated to the companies they regulate as having zero cost, so that they would not be added to the operating costs of electric power plants. With this assumption, the price of electricity in 2010 is projected to be 9 percent less than when the wholesale power market is assumed to behave competitively—still 25 percent higher than without the stringent emission

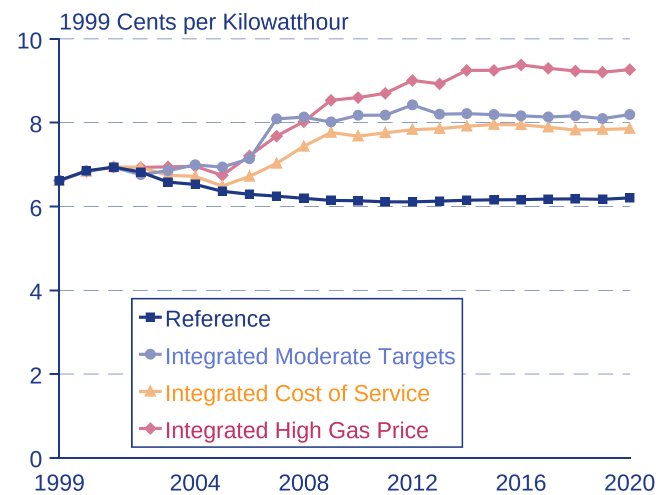
Figure ES12. Projected Electricity Prices in the Reference Case and Integrated Cases with 1990-7% CO_2 Emission Caps, 2000-2020



*Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES13. Projected Electricity Prices in the Reference Case and Integrated Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A. See Chapter 2 of this report, pages 5-10, for case descriptions.

caps. However, power suppliers would have to take additional actions to reduce emissions, because consumers would not be expected to reduce their electricity usage as much as they would if electricity prices reflected the full opportunity costs of emissions allowances. As a result, supplier resource costs would be higher.

Electricity prices could be substantially higher if natural gas prices turn out to be higher than expected. When the reference case technology assumptions for natural gas discovery and production are replaced with assumptions of less robust technology development, the projected price of electricity in 2020 with combined NO_x, SO_2, Hg, and CO_2 emission caps is 9.3 cents per kilowatthour—49 percent above the reference case projection and 8.4 percent above the corresponding projection based on reference case natural gas technology assumptions. The higher natural gas prices would also lead to greater reliance on renewable fuels and more conservation by consumers. Of course, the same technology assumptions would lead to higher natural gas prices in the reference case, even without the imposition of new emissions caps.

Coal Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed to be imposed one at a time, coal consumption and production are expected to be reduced only slightly, because the primary response of power suppliers is projected to be the installation of pollution control equipment rather than a shift in fuel use. When a stringent SO_2 cap is assumed there is a projected shift away from lower sulfur coals, because adding scrubbers to reduce SO_2 would enable power producers to use less expensive higher sulfur coals. Similarly, when a 5-ton Hg cap is assumed, a shift to lower Hg coals is also expected, but adding activated carbon injection systems to capture Hg is expected to be the key compliance strategy.

Reducing CO_2 Emissions

Imposing a CO_2 emission cap, whether at the 1990 level or 7 percent below the 1990 level and with or without stringent NO_x, SO_2, and Hg emission caps, is expected to have a dramatic impact on coal use in the power sector. Because the carbon content of coal is the highest among the fossil fuels, power suppliers are expected to reduce their coal use to meet a CO_2 emission cap. For example, when a CO_2 cap set to 7 percent below the 1990 level is assumed, coal consumption for electricity generation in 2020 is expected to be 59 percent below the reference case level. The impacts are slightly less, with coal consumption in 2020 projected to be 54 percent lower than in the reference case forecast, when a CO_2 cap set to the 1990 level is assumed together with NO_x and SO_2 emission caps.

Natural Gas Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

As with coal, reducing NO_x, SO_2, and Hg emissions is not projected to have large impacts on natural gas markets—generally increasing its use in the power sector by a small amount. More significant impacts are expected when Hg emissions are capped at 5 tons than when either an NO_x or SO_2 emission cap is assumed. For example, when Hg emissions are capped at 5 tons, electricity sector natural gas consumption is projected to be 0.8 trillion cubic feet (11 percent) higher in 2010 than in the reference case.

Reducing CO_2 Emissions

The impact on natural gas markets of capping power sector CO_2 emissions is projected to be much larger than the impacts of other emission caps. Power suppliers are expected to turn to natural gas if they are required to reduce CO_2 emissions. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, electricity sector natural gas consumption is projected to be 10.6 trillion cubic feet in 2010 and 13.4 trillion cubic feet in 2020, as compared with 6.8 trillion cubic feet and 11.2 trillion cubic feet projected for 2010 and 2020 in the reference case. The one exception is when a 20-percent RPS is included with the emission caps. In this case, the projected increased in generation from nonhydroelectric renewable fuels partially reduces the need to turn to natural gas.

To meet the increased demand for natural gas when CO_2 emission caps are assumed, both domestic production and imports of natural gas are expected to grow. Total U.S. gas supplies are projected to reach 38.5 trillion cubic feet in 2020 if stringent caps are placed on power sector NO_x, SO_2, Hg, and CO_2 emissions—approximately 3.2 trillion cubic feet above the reference case projection. Of the 3.2 trillion cubic feet projected to be added, 0.8 trillion cubic feet is expected to come from domestic resources and 2.3 trillion cubic feet from higher imports. The annual increases in production required between 2005 and 2010 would be near record levels, representing a serious challenge for the industry.

The projected increase in natural gas use for electricity generation when a cap on power sector CO_2 emissions is assumed is expected to lead to higher natural gas prices (Figure ES14). For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x,

SO_2, and Hg, the natural gas wellhead price is projected to be $3.66 per thousand cubic feet in 2010 and $3.74 per thousand cubic feet in 2020, as compared with $2.87 and $3.22 in the reference case.

Renewable Fuels Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed either one at a time or together, the projected impact on renewable fuel use for electricity generation is small. Because natural gas plants emit virtually no SO_2 or Hg emissions and very low NO_x emissions, they are expected to remain the most economical option when new electric power plants are needed. As a result, few new renewable power plants are projected to be built in response to stringent NO_x, SO_2, or Hg emissions caps.

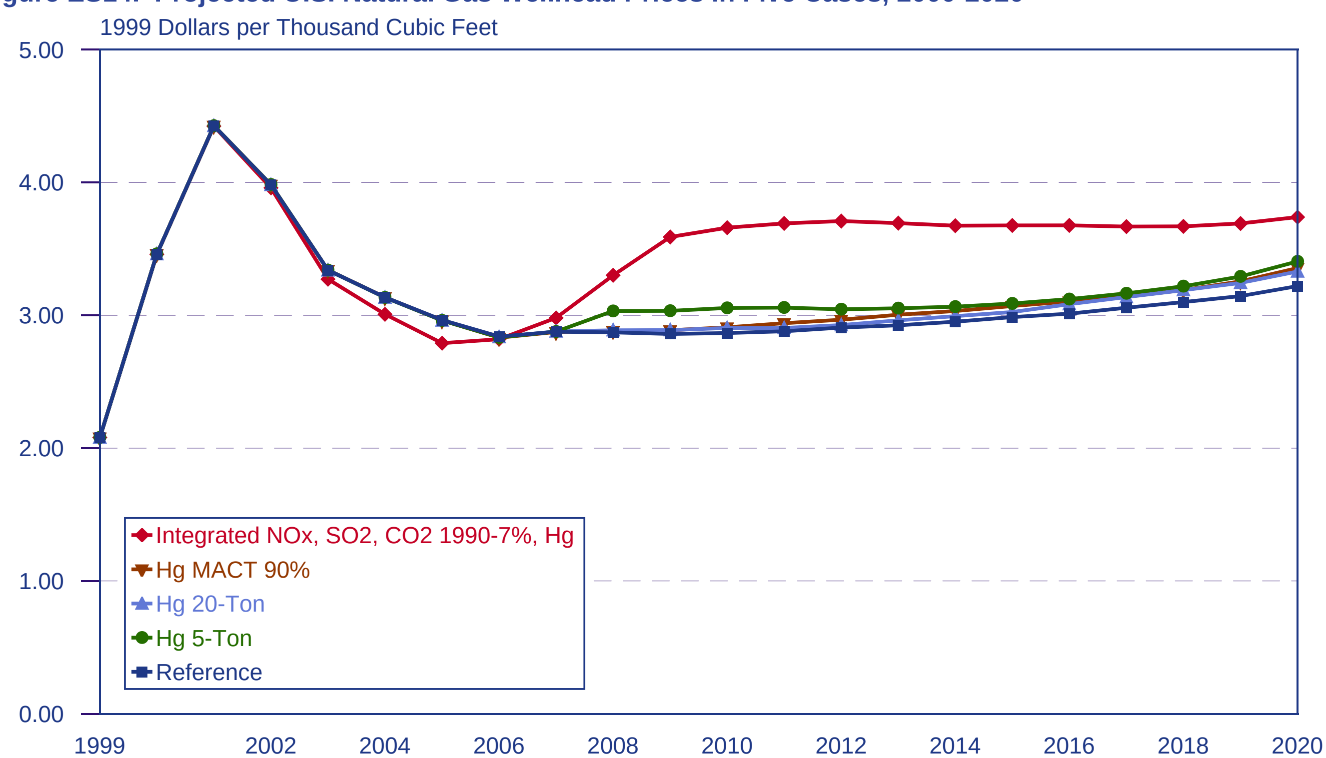
Reducing CO_2 Emissions

Imposing a CO_2 emission cap on the power sector—especially one set to 7 percent below the 1990 level—is projected to have a significant impact on the development of renewable generating facilities (Figure ES15). Although the primary compliance option for meeting a power sector CO_2 emission cap is expected to be increasing generation from natural-gas-fired power plants, the use of renewable fuels is also expected to grow, whether the CO_2 cap is assumed to be imposed alone or in concert with stringent caps on NO_x, SO_2 and Hg. The combination of higher natural gas prices as electricity suppliers consume more and the cost of CO_2 allowances begins to make new renewable plants economical. For example, when a CO_2 cap of 7 percent below the 1990 level is assumed, nonhydroelectric renewables are projected to provide 6.4 percent of U.S. electricity sales in 2020, up from 2.0 percent in 2000 and more than double the reference case projection of 2.8 percent in 2020. The key renewable energy technologies stimulated by a CO_2 cap are expected to be biomass (co-fired in coal plants and used in dedicated plants) and wind.

Implementing a Renewable Portfolio Standard

An RPS reaching 20 percent by 2020 is projected to have a larger impact on the use of renewable fuels for electricity generation than are power sector emission caps on NO_x, SO_2, Hg, and/or CO_2. In general, meeting emissions reduction requirements by adding emissions control equipment and/or changing the mix of fossil fuels used for power production is projected to remain less costly than switching to more expensive renewable alternatives in the absence of an RPS. The key renewables expected to be stimulated by a 20-percent RPS are biomass, wind, and geothermal technologies. By 2020 the generation from qualifying nonhydroelectric renewable technologies is projected to reach 932 billion

Figure ES14. Projected U.S. Natural Gas Wellhead Prices in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

kilowatthours when a 20-percent RPS is assumed, as compared with 135 billion kilowatthours projected in 2020 in the reference case without an RPS.

Macroeconomic Impacts

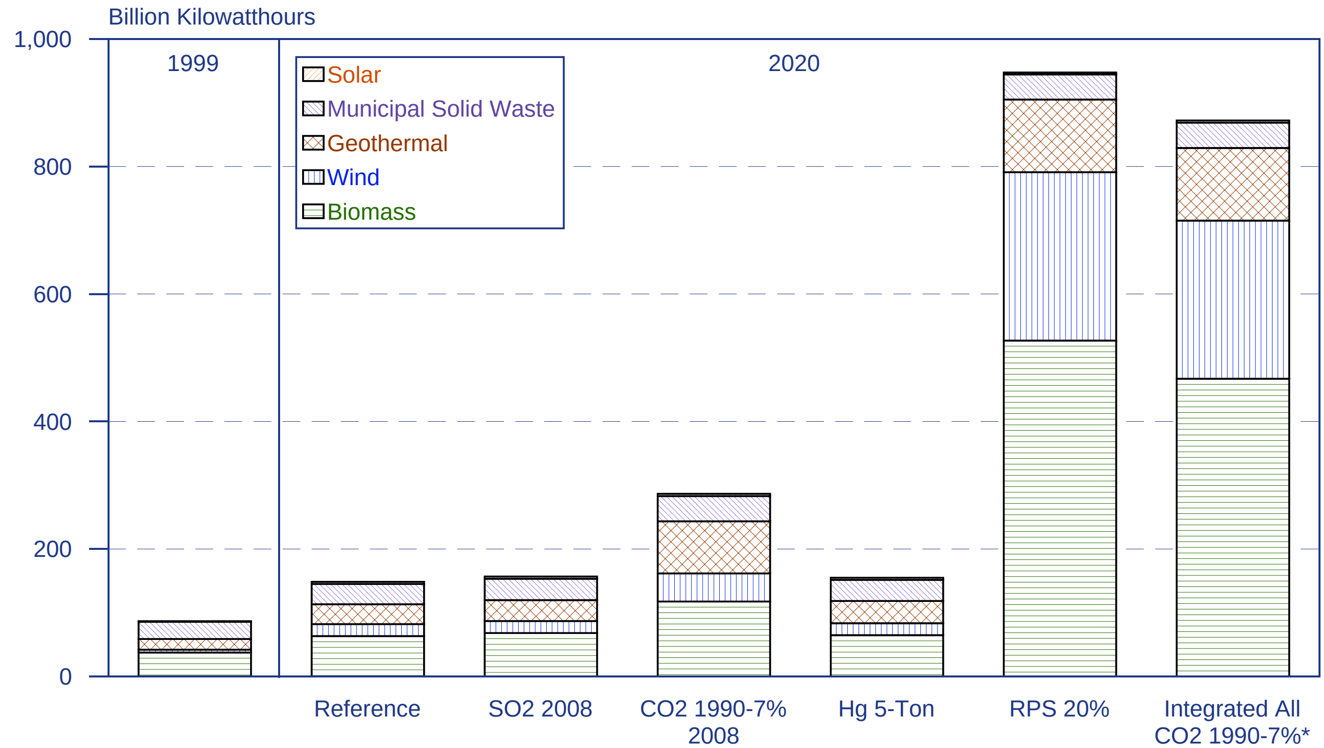
When stringent caps on power sector NO_x, SO_2, Hg, and CO_2 emissions are assumed, higher prices for electricity and natural gas are projected to have an impact on the U.S. economy. Higher energy prices would stimulate consumers to reduce their energy use and industries to shift to less energy-intensive production processes and products. The impact would be largest in the short term, when the economy first reacts to the higher prices. In the long run the economy is projected to recover and return to a more stable growth path. When the four emission caps are first phased in, the unemployment rate is projected to be as much as 0.4 percentage points higher and real gross domestic product as much as much as 0.9 percentage points lower in 2010 than projected in the reference case. By 2020, as the economy adjusts to the higher prices, real GDP is projected to be only 0.1 percent below the reference case level, and the unemployment rate is projected to be near the reference case level.

If, rather than a no-cost allocation of emission allowances, allowances were auctioned by the Federal Government, the economic impact could be different. The key question is what the Federal Government would do with the funds raised in the auction. If funds were returned to power suppliers, the effect would be the same as that of the no-cost allocation. If, on the other hand, they were given back to consumers in a lump-sum payment or through a cut in personal income taxes, the effect would be to help consumers maintain their level of overall consumption but reduce total investment. In the near term, this would be expected to reduce the impact on the economy, with GDP in 2010 projected to be 0.8 percent lower than in the reference case, as compared with 0.9 percent lower GDP with a no-cost allocation. In the longer term, the opposite would be the case: 0.4 percent lower GDP in 2020, as compared with 0.1 percent lower under the no-cost allocation scheme.

Uncertainties

As with any 20-year projections there is considerable uncertainty about the results of this analysis. The evolution of new technologies is 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. It is possible that new, innovative technologies could be developed that would lower the costs of Hg removal. In this analysis, an Hg technology sensitivity case is used to illustrate the potential impacts of

Figure ES15. Projected Electricity Generation from Nonhydroelectric Renewable Energy Sources, 2020



*Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.

Source: National Energy Modeling System, runs M2BASE.D052301A, M2SO208P.D052401A, M2C7B08.D052301A, M2M9008.D052301A, M2RPS20_X.D070601A, and M2P7B08R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

successful technological breakthroughs. It is also possible that for some coal-fired plants Hg emission reductions may be difficult to achieve, particularly to the levels that would be needed to meet a national 5-ton annual cap or a MACT standard of 90-percent removal. In addition, Hg control would be more expensive if power plant waste containing Hg were required to be treated as hazardous waste. Similar uncertainty exists for technologies designed to capture CO_2 emissions and sequester the carbon. Many technologies are being explored, but it is unclear whether they might be economical in the near term. If they do evolve quickly, the need to reduce coal use in the power sector dramatically to meet a CO_2 emission cap could be lessened.

In the case of CO_2 emissions, it is far from certain that the power sector would be able to move from dependence mostly on coal to dependence on natural gas and renewables in a relatively short time period without encountering supply problems. Coal-fired power plants currently account for more than one-half of the electricity produced in the United States, and although natural gas is projected to capture a larger share over the next 20 years in the absence of CO_2 caps as demand for electricity grows, it is not clear that it could at the same time also take over a large part of the market now occupied by coal. Undertaking the amount of power plant construction, natural gas drilling, and pipeline construction needed to replace retiring coal plants would be a serious challenge. In addition, recent history suggests that natural gas resources would need to be developed rapidly in order to avoid price shocks. In this analysis, an integrated case that includes higher natural gas prices illustrates the sensitivity of the projections to variations in future natural gas prices.

The changes required for electricity producers to comply with the power sector emission caps analyzed in this report, especially the caps on CO_2 emissions, are projected to cause significant shifts in the generating capacity and fuels used to produce electricity. There is substantial uncertainty about how the various fuel markets—for coal, natural gas, and renewables—might respond to the projected changes, as well as the degree to which consumers might respond to the projected increases in electricity prices. History does not offer clear guidance as to how the various markets might respond to changes as large as those required by the proposed emissions targets.

With respect to nonhydroelectric renewables, the amounts of new power generation capacity projected to be developed, particularly in cases with an RPS, would multiply existing renewable capacity by up to 16 times by 2020. While total resource estimates suggest that there are considerable wind, biomass, and geothermal resouces in the United States, the technical and economic feasibility of developing the amount called for in the RPS cases is not fully known. This analysis assumes that the development costs will increase as additional resources are used. If the cost increases are not as large as assumed here, the costs of an RPS could be lower than projected.

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. In cases without a CO_2 cap, 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.

Finally, wholesale 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. Numerous policy instruments, including MACT standards, no-cost allowance allocation with cap and trade, allowance auction with cap and trade, and Generation Performance Standard (GPS) allowance allocation with cap and trade, are available. Each of the options would have different price and cost impacts.

1. Introduction

Over the next decade, 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 current regulations. 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 Clean Air Act Amendments of 1990 (CAAA90) required operators of electric power plants to reduce emissions of SO_2 and NO_x. Phase II of the SO_2 reduction program—lowering allowable SO_2 emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000.[1] 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 associated with power plant emissions of NO_x and SO_2, and further reductions in NO_x and SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations will be developed over the next 3 years. Further, if the United States decides that emissions of greenhouse gases need to be mitigated, it is likely that energy-related CO_2 emissions will also have to be reduced.

Because the timing and levels of emission reduction requirements under the new standards are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions. The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO_2 and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO_2 and NO_x today may not be the optimal choice in the future if Hg and CO_2 emissions must also be reduced. Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that reduces SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence.

In both the previous and current Congresses, legislation has been proposed that would require simultaneous reductions of multiple emissions. Several bills were introduced in the 106th Congress to address these issues: S. 1369, the Clean Energy Act of 1999, introduced by Senator Jeffords; S. 1949, the Clean Power Plant and Modernization Act of 1999, introduced by Senator Leahy; H.R. 2900, the Clean Smokestacks Act of 1999, introduced by Congressman Waxman; H.R. 2645, the Consumer, Worker, and Environmental Protection Act of 1999, introduced by Congressman Kucinich; and H.R. 2980, the Clean Power Plant Act of 1999, introduced by Congressman Allen.[2]

Additional bills introduced in the 107th Congress with similar goals include S. 556, the Clean Power Act of 2001, introduced by Senator Jeffords; H.R. 1256, the Clean Smokestacks Act of 2001, introduced by Congressman Waxman; and H.R. 1335, the Clean Power Plant Act of 2001, introduced by Congressman Allen. Each of the

[1]Because power companies accumulated (banked) emissions allowances during Phase I of the program (1995 to 1999), the Phase II cap of 8.95 million tons per year will not become binding until the banked allowances have been exhausted.

[2]For more information on these bills see Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000), pp. 1 and 2.

bills introduced in the 106th and 107th Congresses contains provisions to reduce power plant emissions of NO_x, SO_2, CO_2, and Hg over the next decade. The bills use different approaches—traditional technology-specific emission standards, generation performance standards, explicit emission caps with trading programs, or combinations of the three—but all call for significant reductions. In addition, the Bush Administration's National Energy Policy recommends the establishment of "mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides and mercury."[3] While differences exist on what the appropriate emission targets should be and how the program should be implemented, it is generally agreed that a more predictable emission reduction policy is worth pursuing.

The analysis described in this report was conducted at the request of the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform.[4] In its request the Subcommittee asked the Energy Information Administration (EIA) to "analyze the potential costs of various multi-emission strategies to reduce the air emissions from electric power plants." The Subcommittee requested that EIA examine cases with alternative NO_x, SO_2, CO_2, and Hg emission reductions, with and without a renewable portfolio standard (RPS) requiring a specified portion of all electricity sales to come from generators that use nonhydroelectric renewable fuels.

At the request of the Subcommittee, EIA prepared an initial report (referred to here as "the earlier EIA report") that focused on the impacts of reducing power sector NO_x, SO_2, and CO_2 emissions.[5] The current report extends EIA's earlier analysis to add the impacts of reducing power sector Hg emissions and introducing RPS requirements. Expected costs to the energy sector and to consumers of meeting the specified emission caps and the RPS are examined (see Chapter 2 for a discussion of the specific scenarios prepared). 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. The bibliography for this report includes several studies that address the benefits of reducing emissions.

The analysis presented in this report should be seen as an examination of the steps that power suppliers might take to meet the emission caps specified in the Subcommittee's request for analysis. The specific design of the cases—timing, emission cap levels, policy instruments used, etc.—is important and should be kept in mind when the results are reviewed.[6] For example, all the analysis cases assume that market participants—power suppliers, consumers, and coal, natural gas, and renewable fuel suppliers—would become aware of impending emission caps before their target dates and would begin to take action accordingly. If it had been assumed that market participants would not anticipate the emission caps, the results would be different. In an earlier EIA study that looked at alternative program start dates for imposing a CO_2 emissions cap (or carbon cap), an earlier start date and longer phase-in period were found to smooth the transition of the economy to the longer run target.[7]

This study is not intended to be an analysis of any of the specific congressional bills that have been proposed, and the impacts estimated here should not be considered as representing the consequences of specific legislative proposals. All the congressional proposals include provisions other than the emission caps and RPS requirements 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 specified.

The purpose of this report is to respond to the Subcommittee's request; however, it also provides an important secondary benefit by establishing a framework for analysis that evolved in the research and modeling undertaken to complete the analysis.

During the course of this work, many choices had to be made about specific configurations for mercury mitigation technologies and their costs and performance characteristics; the response of fuels markets to much more stringent emission constraints; and the reaction of consumers to higher prices for electricity, coal, and natural gas. In an attempt to capture the uncertainties associated

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

[4]In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

[5]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide,* SR / OIAF / 2000-05 (Washington, DC, December 2000). See also J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov / oiaf / servicerpt / gps / gpsstudy.html.

[6]For a discussion of one possible alternative policy instrument, see the box on "Generation Performance Standards" on page 14 of the earlier EIA report. See also J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov / oiaf / servicerpt / gps / gpsstudy.html.

[7]Energy Information Administration, *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR / OIAF / 99-02 (Washington, DC, July 1999).

with these choices, this report shows a wide range of cases with alternative assumptions for many of the major inputs. It would be impossible, however, to capture the full range of possible outcomes that could result from the policies examined in this analysis. Rather, this report should be seen as an indicator of a possible set of energy market responses to multiple emission targets, providing a basic platform from which interested readers can obtain broad estimates of energy prices, supply, and demand in response to alternate sets of assumptions.

2. Analysis Cases and Methodology

Background

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

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

Reference Case

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

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

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

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

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

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

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

Analysis Cases

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

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

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

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

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

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

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

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

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

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

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

Table 1. Reference and Analysis Cases

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

[a]The impacts of current State RPS programs are estimated off line and input as new plant construction.

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

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

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

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

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

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

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

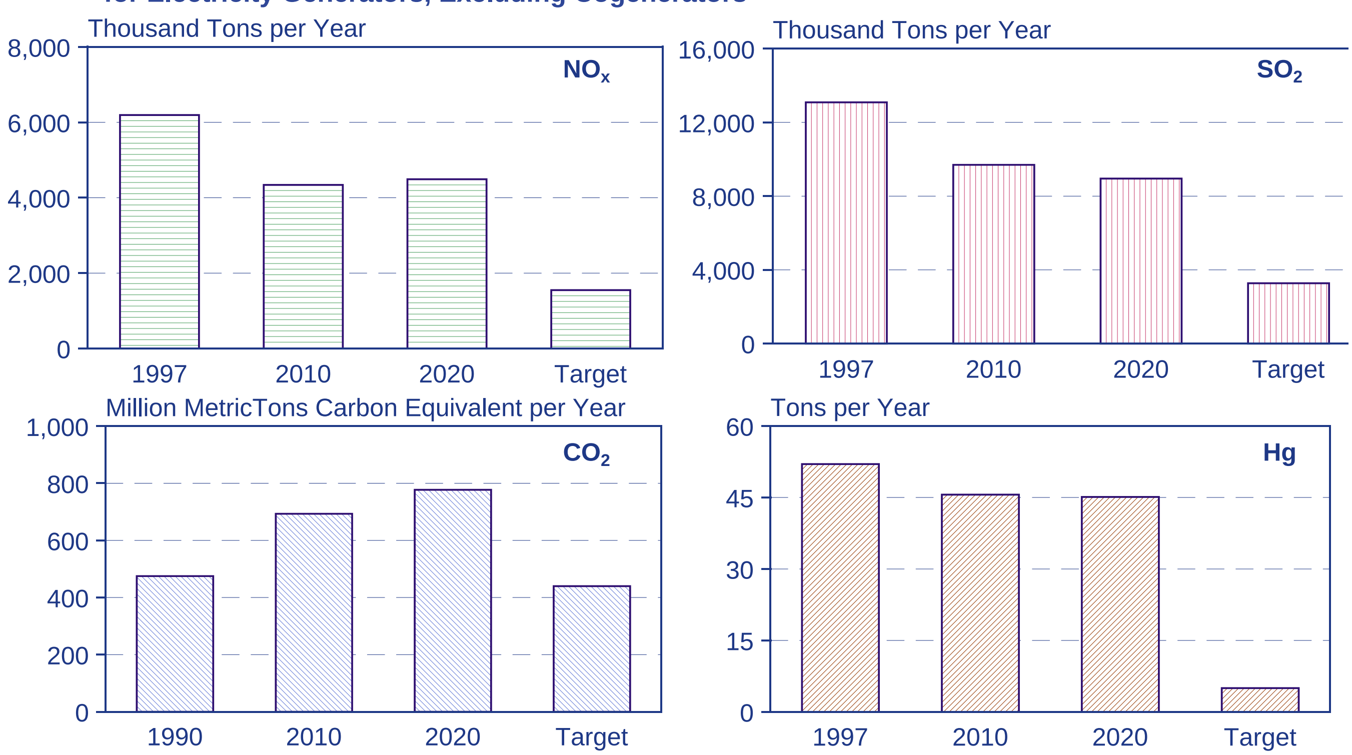
[a]Two alternative CO_2 emissions targets are used: 1990 level (475 million metric tons carbon equivalent) and 1990-7% level (440 million metric tons carbon equivalent).

NA = not applicable.

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

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

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



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

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

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

Representation of New Environmental Rules and Regulations

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

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

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

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

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

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

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

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

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

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

Sensitivity Cases

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

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

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

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

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

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

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

Methodology

NEMS Representation

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

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

Table 3. Sensitivity Cases

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

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

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

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

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

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

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

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

Table 4. National Energy Modeling System Energy Activities

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

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

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

Electricity Market Module

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

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

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

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

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

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

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

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

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

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

Representation of SO_2, NO_x, and CO_2 Emission Reductions

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

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

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

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

Representation of Hg Emission Reductions in the EMM

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

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

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

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

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

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

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

[a]SCRs are assumed to reduce Hg emissions only when combined with a wet scrubber designed to remove SO_2.
[b]CSEs do not remove additional Hg when combined with a dry scrubber.
Notes: BH = bag house, CSE = cold side electrostatic precipitator, FF = fabric filter, HSE = hot side electrostatic precipitator, SC = spray cooler, SCR = selective catalytic reduction. NA = not applicable. An emissions modification factor (EMF) of 0.93 is assumed for all boiler configurations and is incorporated in the derivation of the combined EMFs.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Power Sector Mercury Emissions

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

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

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

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

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

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

(continued on page 17)

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

Power Sector Mercury Emissions (Continued)

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

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

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

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

where:

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

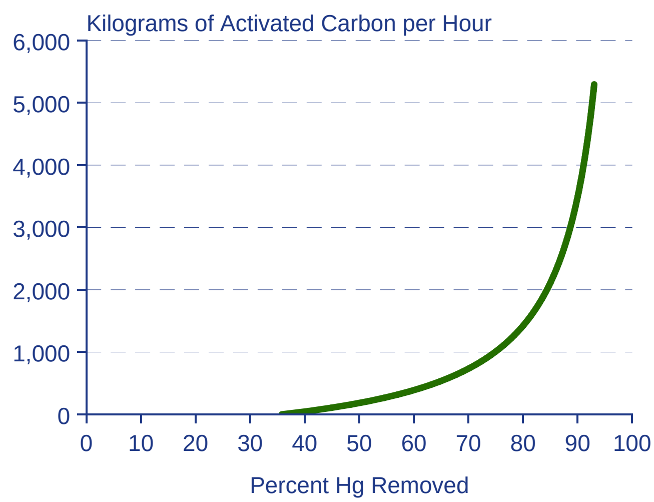
Figure 2 illustrates the impact of injecting activated carbon for a common plant configuration—a 500-megawatt coal-fired power plant using bituminous coal with an electrostatic precipitator. The percentage of Hg removed increases with the amount of activated carbon injected; however, the amount of activated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

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

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

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

Figure 2. Activated Carbon Use for Hg Removal



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

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

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

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

Representation of the Renewable Portfolio Standard

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

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

Coal Market Module

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

Representation of Coal Rank in the NEMS Coal Market Module

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

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

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

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

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

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

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

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

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

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

Representation of Hg Emission Reductions in the CMM

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

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

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

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

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

Renewable Fuels Module

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

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

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

NA = not available.

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

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

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

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

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

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

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

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

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

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

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

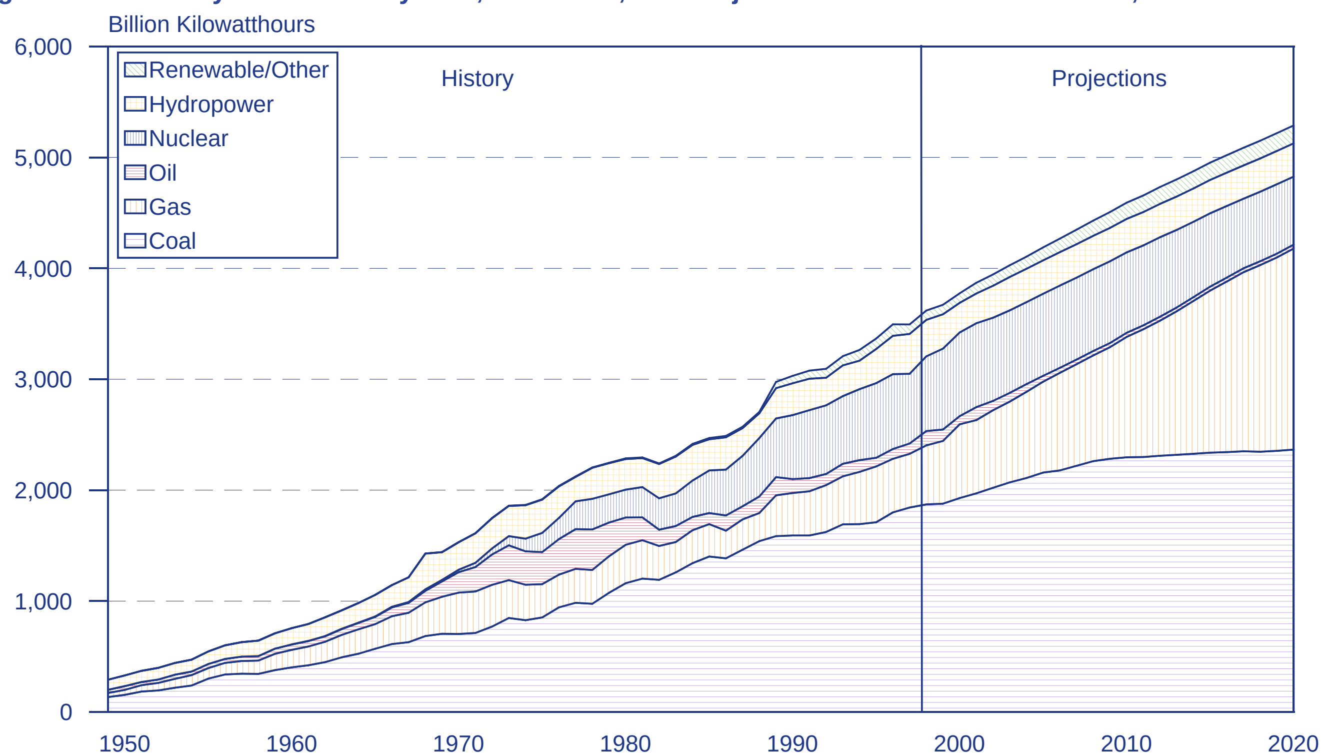
3. Electricity Market Impacts

Introduction

For the past 50 years, electricity production in the United States has been dominated by electric power plants that burn fossil fuels. Beginning with small hydroelectric facilities in the early 20th century, the industry soon turned to fossil fuels, particularly coal. An abundance of economical coal has made it the dominant fuel in U.S. electricity production since 1950 (Figure 3). Changes occurred as relative fuel prices varied and new generating technologies evolved, but coal continued to account for more than one-half of total generation. For example, in the early 1970s oil use increased, but the price increases and regulatory changes of the late 1970s and early 1980s led to a rapid decline in the use of oil by the mid-1980s. The role played by nuclear power also grew in the 1970s and 1980s, when a large number of nuclear plants were constructed. The contribution from nuclear plants continued to grow in the 1990s because of performance improvements at existing plants, but no new plants have been ordered in the past 25 years. Renewables, predominantly hydroelectric power, currently provide between 9 and 11 percent of total generation, depending on the availability of water from year to year.

Over the next 20 years coal use for power generation is expected to continue to grow, but at a slower rate than in the past. Only a relatively small number of new coal-fired plants are expected to be built, and existing coal plants are projected to be used more as demand for electricity grows. When new plants are needed, natural-gas-fired combustion turbines and combined-cycle plants are expected to be the most economical options for most uses. New natural-gas-fired combined-cycle plants cost approximately half as much to build as new coal-fired plants, are more efficient, and have lower emissions. These factors generally offset the higher fuel cost for natural gas. Unless the high gas prices seen recently are sustained for many years, new natural gas plants are expected to dominate new plant additions. Oil-fired generation is expected to continue to decline while total renewable generation increases slightly in the overall generation mix. Nuclear power is projected to continue to contribute, but some older nuclear plants are expected to be retired in the later years of the

Figure 3. 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 M2BASE.D060801A.

forecast, and no new nuclear plants are projected to be built in the United States through 2020.

This chapter discusses the impact that the imposition of a renewable portfolio standard (RPS) and emission caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2) is projected to have on electricity generation. The RPS and emission caps are expected to affect capacity planning and plant retirement decisions, investments in emissions control equipment, fuel choices for generation, electricity costs, and consumer prices. In turn, higher electricity prices are projected to cause consumers to alter their electricity use by buying more efficient appliances, switching to other fuels, or generating their own electricity. Potential impacts on total CO_2 emissions are also discussed, as well as key uncertainties in the analysis.[20]

Analysis of NO_x and SO_2 Caps

In the reference case, existing laws and regulations affect the projections of power sector NO_x and SO_2 emissions. NO_x emissions are projected to increase slightly between 2000 and 2003 before declining in 2004, when the 19-State summer season NO_x SIP Call and existing regulations will require stringent summertime controls. The main compliance strategy for meeting the SIP Call emission limits is expected to be the installation of emission control equipment at existing electric power plants. SO_2 emissions are expected to decline steadily as the Clean Air Act Amendments of 1990 (CAAA90) Phase II 8.95 million ton cap takes effect and allowances previously banked by power companies are used. By 2010 the banked allowances are projected to be exhausted, and electricity generators are expected to comply with the 8.95 million ton annual cap on SO_2 emissions through the remainder of the projections. The main compliance strategy for reducing SO_2 emissions is expected to be a growing shift toward lower sulfur coal. Scrubbers are also expected to be added to a relatively small number of plants to reduce their emissions.

When tighter NO_x and SO_2 emission caps are assumed, the amount of emission control equipment added is projected to increase dramatically (Table 7).[21] For example, in the NO_x 2008 case, selective noncatalytic reduction (SNCR) or selective catalytic reduction (SCR) equipment is projected to be added to 274 gigawatts of existing capacity, as compared with 136 gigawatts in the reference case. In the SO_2 2008 case, scrubbers are projected to be added to 139 gigawatts of existing capacity, compared with 15 gigawatts in the reference case. The tighter NO_x and SO_2 caps also are projected to have dramatic impacts on the prices of emissions allowances, particularly for SO_2. The SO_2 allowance price in 2010 is projected to be $187 per ton in the reference case but $794 per ton in the SO_2 2008 case. In the SO_2 2008 case, scrubber additions at some plants using medium- or low-sulfur coal lead to higher average costs per ton of SO_2 removed. The NO_x allowance prices in the reference and NO_x 2008 cases are not comparable, because the reference case represents a 5-month summer season NO_x cap in 19 States, while the NO_x 2008 case represents a nationwide annual cap on NO_x emissions. In general, the NO_x allowance prices under an annual cap are expected to be less than those under a seasonal cap, because the costs associated with investments in control equipment are spread over the entire year rather than just the summer.[22]

NO_x emissions are expected to fall to the 1.6 million ton cap by the target date of 2008 in the NO_x 2008 case. In the SO_2 2008 case, however, it is assumed that electricity suppliers will be allowed to use any allowances they have already accumulated under the CAAA90 SO_2 program. Coming into 2000 electricity suppliers had accumulated nearly 12 million tons of SO_2 allowances. As a result, the SO_2 emission level in the SO_2 2008 case is not expected to meet the 3.3 million ton cap until 2011, 3 years after the cap first takes effect.

The addition of emissions control equipment and other steps taken to reduce emissions in the NO_x 2008 and SO_2 2008 cases are expected to have an impact on electricity prices and electricity supplier costs. From 2008 to 2020, annual revenues from retail electricity sales are expected to average $1 billion to $2 billion more in the NO_x 2008 and SO_2 2008 cases than in the reference case, and from 2005 to 2015, overall average electricity prices are projected to be 1 percent higher than in the reference case. In the NO_x 2008 case electricity suppliers are projected to

[20]This analysis employs a no-cost cap and trade system for emissions allowances for all required emission reductions. For a discussion of the impacts of alternative policy instruments see J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf (April 2001); and D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, *The Effect of Allowance Allocation on the Cost and Efficiency of Carbon Emission Trading* (Washington, DC: Resources for the Future, April 2001).

[21]Sensitivity cases with less stringent NO_x and SO_2 caps were prepared in the earlier EIA report. See Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide,* SR/OIAF/2000-05 (Washington, DC, December 2000).

[22]For similar NO_x allowance price results with an annual versus a seasonal NO_x emission cap, see K. Palmer, D. Burtraw, R. Bhanvitkar, and A. Paul, "Restructuring and Cost of Reducing NO_x Emissions in Electricity Generation," Resources for the Future Discussion Paper 01-10 (Washington, DC, March 2001); and D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, "Cost-Effective Reduction of NO_x Emissions from Electricity Generation," Resources for the Future Discussion Paper 00-55 (Washington, DC, December 2000).

spend $13 billion on SCRs, and in the SO_2 2008 cases they are projected to spend $33 billion on SO_2 control equipment.

The addition of equipment to reduce SO_2 in the SO_2 2008 case is also projected to reduce Hg emissions, because scrubbers designed primarily to reduce SO_2 also reduce Hg emissions. Hg emissions are projected to be 45 tons in 2020 in the reference case, compared with 33 tons in the SO_2 2008 case, a 28-percent difference.

While the projected average price impacts in the NO_x 2008 and SO_2 2008 cases are not large, the potential exists for other impacts in the short run. The amount of emission control equipment needed in the NO_x 2008 and SO_2 2008 cases[23] could cause operational problems for electricity grids under some conditions. Typically, when new emissions controls are added, particularly SCRs, a plant must be off line for a time so that final connections can be made. Several recent studies have examined whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the NO_x SIP Call might create problems for system operation and reliability. While the results of the studies differed, several factors were identified as critical to the analysis, including the calendar time between the announcement of the program and the compliance date, the growth in demand for electricity, the availability of sufficient reserve capacity, coordination among companies performing the work on their plants, and the interconnection time needed for each plant.[24]

Table 7. Key Results for the Electricity Generation Sector in NO_x and SO_2 Emission Cap Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Emissions (Tons)							
Hg	43	46	44	32	45	44	33
SO_2 (Millions)	12.7	9.7	9.7	3.6	8.9	8.9	3.3
NO_x (Millions)	5.7	4.3	1.6	4.3	4.5	1.6	4.5
CO_2[a]	556	693	687	684	777	770	775
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	198	794	241	203	983
NO_x (per Ton)	NA	4,391	2,405	3,668	5,037	3,201	5,229
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.23	6.17	6.21	6.24	6.21
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,270	2,237	2,366	2,339	2,321
Oil and Other	106	50	47	38	49	46	41
Natural Gas	593	1,085	1,105	1,135	1,813	1,832	1,854
Nuclear	734	725	725	725	613	617	613
Renewable	401	440	439	449	452	452	460
Total	3,728	4,597	4,587	4,585	5,294	5,286	5,289
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	6	125	15	19	139
SCR	0	93	237	85	93	242	86
SNCR	0	26	22	38	43	32	45

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NOX08.D060801A, and M2SO208P.D061201A.

[23]The earlier EIA report included cases with a 2005 target date. The earlier date increases the potential for short-term reliability and pricing problems.

[24]North American Electric Reliability Council, *Reliability Impacts of the EPA NO_x SIP Call* (Washington, DC, February 2000); U.S. Environmental Protection Agency, *Feasibility of Installing NO_x Control Technologies by May 2003* (Washington, DC, September 1998); and Utility Air Regulatory Group, *The Impact of EPA's Regional SIP Call on Reliability of the Electric Power Supply in the Eastern United States* (Washington, DC, September 1998).

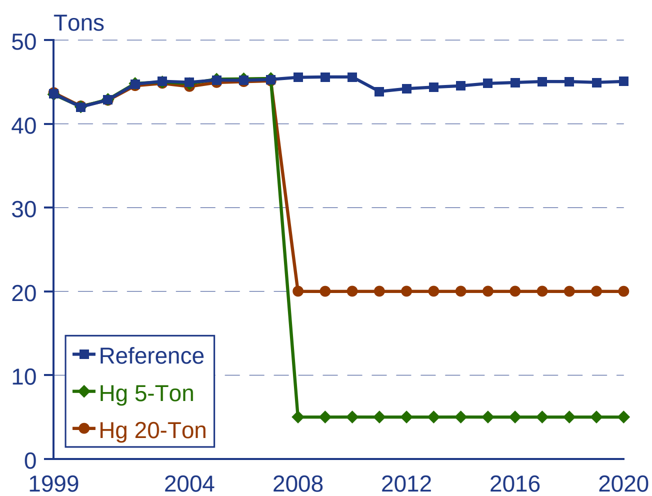
Analysis of Hg Emission Caps

In the reference case, power sector Hg emissions are projected to remain fairly steady over the next 20 years (Figure 4). From 42 tons in 2000, they are projected to reach 46 tons in 2010 and 45 tons in 2020. Although power sector coal consumption is projected to increase by 23 percent over the next 20 years, the shift to relatively low Hg western coal and the addition of scrubbers to 15 gigawatts of capacity to reduce SO_2 emissions to comply with the requirements of CAAA90 Phase II dampen the increase in Hg emissions that would otherwise be expected. In the first few years of the projections, power sector Hg emissions are projected to increase slightly as coal use grows, but as the shift to low-sulfur western subbituminous coal to reduce SO_2 emissions continues, the increase levels off by the middle years of the projections. Between 2000 and 2020 the average Hg content of the coal used in the power sector is projected to fall from 7.36 pounds per trillion Btu to 7.03 pounds per trillion Btu, a 5-percent decline.

The actions projected to be taken to reduce Hg emissions, their costs, and their price impacts are sensitive to the emission cap level, the assumptions made about the cost and performance of Hg removal technologies, and the policy instrument used to reduce them. Data on Hg emissions and technologies for reducing them have been collected in recent years, but significant uncertainty remains. Readers should keep this in mind when reviewing the results presented here. In addition, the rapid reductions shown in Figure 4 may be difficult to achieve.

In the Hg 5-ton case, which assumes a 5-ton annual cap on national Hg emissions in the power sector beginning

Figure 4. Projected Electricity Generation Sector Mercury Emissions in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M6008.D060801A.

in 2008, the shift to coal with lower Hg content is expected to be more pronounced than in the reference case (Table 8). Between 2000 and 2020 the average Hg content of the coal used in the power sector is projected to decline from 7.36 pounds per trillion Btu to 6.28 pounds per trillion Btu, a 15-percent reduction. Even with this shift, however, it is expected that power plant operators will need to use activated carbon injection at many plants to reach the 5-ton cap. Supplemental fabric filters and activated carbon injection systems are projected to be added to approximately 263 gigawatts of coal-fired capacity, or 84 percent of the total. At nearly all coal-fired power plants, some action would need to be taken to reduce Hg emissions.

It should be noted that the Hg content of coal burned at all U.S. electric power plants totals about 73 tons annually. Therefore, a 5-ton annual cap on Hg emissions would require that, on average, 93 percent of the Hg initially contained in the coal burned for power production would have to be removed. At many plants, in order to accomplish reductions of that magnitude, activated carbon injection would have to be employed at rates that have never been tested. Thus, there is significant uncertainty about the results. In addition, the amount of activated carbon that must be injected per pound of Hg removed increases as the percentage removal grows. In other words, the amount of activated carbon needed to remove the second pound of Hg is larger than the amount needed to remove the first pound, and the amount needed to remove the third pound is larger still. In economists' terms, the marginal cost of injecting activated carbon to remove Hg increases as the quantity to be removed grows.

Although the removal cost per pound of Hg is expected to be fairly high, its impact on the economics of operating coal plants is not expected to be large for most plants. As a result, the Hg cap is not projected to cause a large change in fuel use for electricity generation. Relative to the reference case, natural gas use is expected to be higher and coal use lower in the Hg 5-ton case. In addition, because more than 90 percent of capacity additions in the reference case are projected to be natural-gas-fired plants (which do not produce Hg emissions), their economic attractiveness is not expected to be affected by the Hg cap. The projected level of generation from renewable fuels in the Hg 5-ton case is also similar to that in the reference case.

Allowance prices for Hg emissions are projected to be much higher than those for NO_x and SO_2, for several reasons. First, the volume of Hg produced by a typical coal-fired power plant is dramatically smaller than the volume of NO_x or SO_2 produced. For example, a 500-megawatt coal plant with a cold-side electrostatic precipitator and no scrubber, using bituminous coal with an Hg content of 7 pounds per trillion Btu and

1 percent sulfur by weight, would produce more than 27,000 tons of SO_2 annually but only 230 pounds of Hg. As a result, even if the total costs of removing 90 percent of the SO_2 or 90 percent of the Hg were the same, the costs per unit removed would be much higher for Hg than for SO_2. Second, as mentioned previously, the cost per pound of Hg removed by activated carbon injection increases as more is removed. Figures 5 and 6 illustrate this point for a common coal plant configuration—a plant with a cold-side electrostatic precipitator, no SO_2 scrubber and no post-combustion NO_x control, using bituminous coal containing 10 pounds of Hg per trillion Btu of coal, and employing simple activated carbon injection.

As shown in Figure 5, the average cost of removing Hg using activated carbon injection increases as the total percentage removed grows. To achieve 90 percent removal, the average cost of Hg removed is over $70,000 per pound.[25] While the average and marginal cost values vary considerably among different coal plant configurations—the one shown is relatively high cost—the relationship between them is consistent: average costs are much lower than marginal costs, and the marginal costs tend to increase rapidly as the degree of removal increases. In addition, as shown in Figure 6, the per-pound costs of removal increase significantly when the total percentage removed increases from 80 percent to 90 percent. The cost of removing the last unit of Hg to achieve 90 percent removal is over $800,000 per pound.

Efforts to meet the 5-ton Hg cap are projected to have significant impacts on SO_2 and NO_x emissions and allowance prices. Because scrubbers designed to remove SO_2 and SCR equipment designed to remove NO_x are also projected to be added to reduce Hg emissions, the allowance prices for SO_2 and NO_x are expected to be lower than they are in the reference case. In fact, in the later years of the projections SO_2 allowance prices are at or near zero in the Hg 5-ton case. Scrubbers are projected

Table 8. Key Results for the Electricity Generation Sector in Hg Emission Cap Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Emissions (Tons)							
Hg	43	46	5	20	45	5	20
SO_2 (Millions)	12.7	9.7	8.8	9.7	8.9	7.2	9.0
NO_x (Millions)	5.7	4.3	3.3	3.4	4.5	3.5	3.5
CO_2[a]	556	693	664	684	777	748	769
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	178,959	72,519	NA	193,973	68,918
SO_2 (per Ton)	207	187	0	0	241	0	12
NO_x (per Ton)	NA	4,391	2,651	3,669	5,037	4,545	4,645
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.38	6.23	6.21	6.37	6.28
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,134	2,237	2,366	2,200	2,318
Oil and Other	106	50	49	48	49	51	52
Natural Gas	593	1,085	1,218	1,133	1,813	1,951	1,847
Nuclear	734	725	725	725	613	613	617
Renewable	401	440	444	439	452	459	452
Total	3,728	4,597	4,570	4,583	5,294	5,273	5,285
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	18	43	15	52	43
SCR	0	93	95	92	93	99	100
SNCR	0	26	23	26	43	25	30
Hg Emission Controls							
Spray Cooling	0	0	241	34	0	254	40
Fabric Filter	0	0	261	38	0	263	43

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M6008.D060801A.

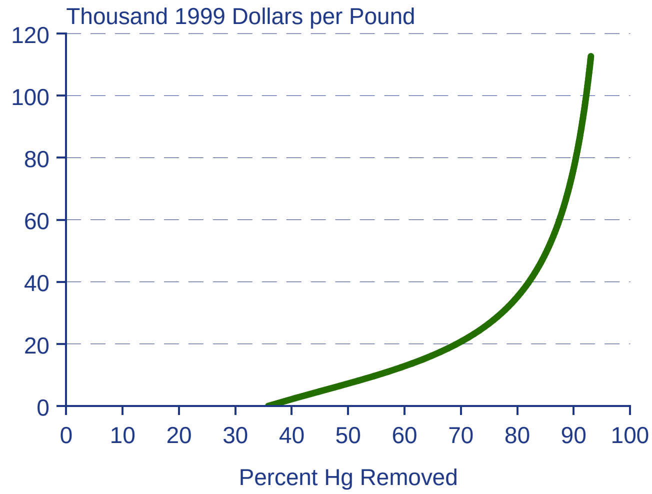
[25]This discussion only includes the cost of the activated carbon. Some capital investment and operations and maintenance costs will also be required but they are very small when compared with the cost of the activated carbon.

to be added to approximately 52 gigawatts of existing capacity in the Hg 5-ton case, 37 gigawatts more than in the reference case. By 2020, both NO_x and SO_2 emissions are projected to be below their reference case levels. In fact, SO_2 emissions are projected to be 1.7 million tons below the 8.95 million ton CAAA90 cap. In addition, although no cap on CO_2 emissions is assumed in the Hg 5-ton case, power sector CO_2 emissions are projected to be lower than in the reference case because of reduced coal use. In 2010, power sector CO_2 emissions are projected to total 664 million metric tons carbon equivalent in the Hg 5-ton case, 29 million metric tons (4 percent) lower than in the reference case.[26]

Both producer resource costs[27] and retail electricity prices are projected to be higher in the Hg 5-ton case as a result of expenditures made to reduce Hg emissions, higher natural gas prices resulting from increased demand, and Hg allowance costs (impacting prices and not resource costs) (Figure 7). Price increases brought about by efforts to reduce Hg emissions are expected to be larger than those in the NO_x 2008 and SO_2 2008 cases. In the Hg 5-ton case, electricity prices in 2010 are projected to be 3.9 percent higher than in the reference case, and in 2020 they are 2.6 percent higher. Total revenues from retail electricity sales are projected to be $8.4 billion higher than in the reference case in 2010 and $6.1 billion higher in 2020. Per pound of Hg emissions reduced, U.S. consumers are projected to pay $105,000 in 2010 and $76,300 in 2020, on average.

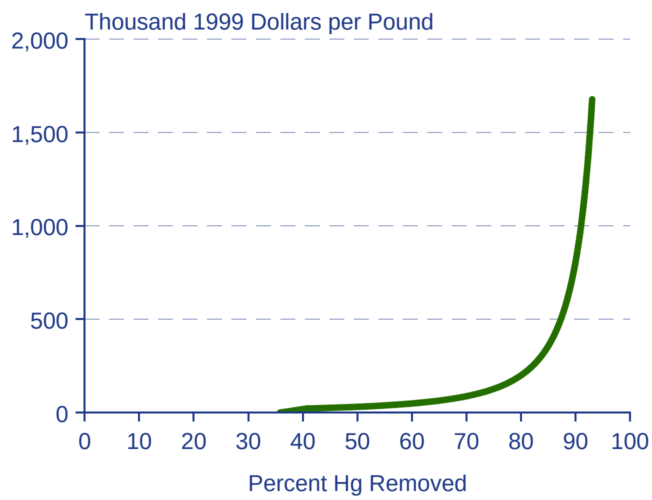
The Hg case with a less stringent emission cap demonstrates the sensitivity of the results to the level of reduction required. A 20-ton cap imposed in 2008 is projected to lead to much more modest changes from the reference case than does the Hg 5-ton case. The less stringent cap in the Hg 20-ton case leads to much lower Hg allowance costs and lower electricity price impacts than in the Hg 5-ton case. For example, the Hg allowance price in 2010

Figure 5. Average Cost of Activated Carbon per Pound of Hg Removed



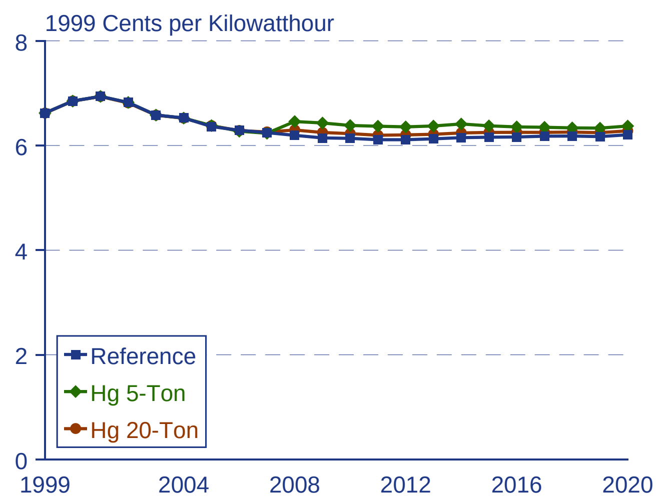
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 6. Marginal Cost of Activated Carbon Per Pound of Hg Removed



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

Figure 7. Projected Electricity Prices in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M6008.D060801A.

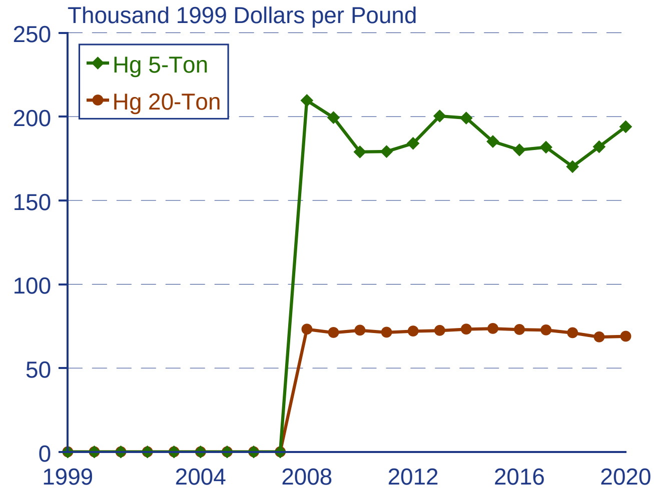
[26]Throughout this report carbon dioxide (CO_2) emissions are reported in terms of metric tons carbon equivalent. In other words, they are reported in carbon units, defined as the weight of the carbon content of carbon dioxide (i.e., the "C" in CO_2). To convert to metric tons of carbon dioxide multiply by 44 / 12 or 3.6667. For more discussion of this issue, see Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999,* DOE / EIA-0573(99) (Washington, DC, October 2000).

[27]Resource costs include total fuel costs, operations and maintenance costs, and investment costs. They do not include allowance costs.

is projected to be $178,959 per pound in the Hg 5-ton case but only $72,519 per pound in the Hg 20-ton case (Figure 8). Similarly, while the price of electricity in the 5-ton case is projected to be 3.9 percent higher than in the reference case in 2010, the difference is only 1.5 percent in the 20-ton case.

The case with alternative assumptions about the cost and performance of Hg removal technologies demonstrates the sensitivity of the results to technological uncertainty (Table 9). Relative to the results in the Hg 5-ton case, the Hg 5-ton recycle case shows much lower cost and price impacts, assuming that activated carbon requirements can be reduced by 90 percent by recycling the carbon through the plant multiple times. It is impossible to say whether this level of recycling is feasible; however, the vast majority of the activated carbon injected in a once-through system does not make contact with Hg and could be used again. Thus, a fairly high level of recycling may be feasible. The price of an Hg

Figure 8. Projected Mercury Allowance Prices in Hg Cap Cases, 2000-2020



Source: National Energy Modeling System, runs M2M9008.D060801A and M2M6008.D060801A.

Table 9. Key Results for the Electricity Generation Sector in Hg Emission Cap Technology Cases, 2010 and 2020

Projection	1999	2010 Reference	2010 Hg 5-Ton Recycle	2010 Hg MACT 90%	2020 Reference	2020 Hg 5-Ton Recycle	2020 Hg MACT 90%
Emissions (Tons)							
Hg	43	46	5	8	45	5	8
SO_2 (Millions)	12.7	9.7	9.7	9.7	8.9	8.9	8.9
NO_x (Millions)	5.7	4.3	3.4	3.4	4.5	3.5	3.6
CO_2[a]	556	693	675	690	777	757	773
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	40,211	NA	NA	45,785	NA
SO_2 (per Ton)	207	187	118	114	241	109	145
NO_x (per Ton)	NA	4,391	3,140	4,162	5,037	4,682	4,798
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.22	6.19	6.21	6.30	6.21
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,188	2,266	2,366	2,249	2,336
Oil and Other	106	50	47	48	49	49	48
Natural Gas	593	1,085	1,174	1,115	1,813	1,907	1,842
Nuclear	734	725	725	725	613	613	617
Renewable	401	440	451	436	452	464	451
Total	3,728	4,597	4,585	4,590	5,294	5,281	5,294
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	12	27	15	25	27
SCR	0	93	96	94	93	98	95
SNCR	0	26	22	25	43	27	36
Hg Emission Controls							
Spray Cooling	0	0	148	169	0	156	174
Fabric Filter	0	0	238	187	0	245	192

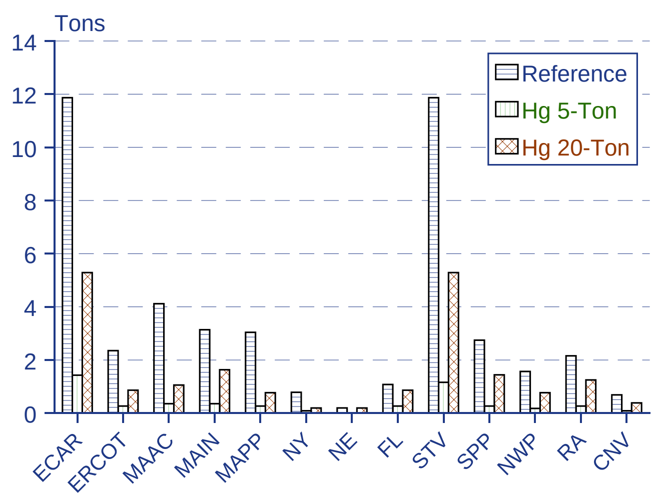
[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008A.D060801A, and M2M9008M.D060801A.

allowance in 2010 is expected to be $40,211 per pound in the Hg 5-ton recycle case, 78 percent lower than in the Hg 5-ton case. The price of electricity in 2010 is expected to be 6.2 cents per kilowatthour in the Hg 5-ton recycle case, 2.5 percent lower than in the Hg 5-ton case, and only 1.3 percent higher than in the reference case.

The activated carbon recycling technology is only one of several innovative Hg control technologies being studied, and the results in the Hg 5-ton recycle case are indicative of the potential impacts of general technological improvement. Because of the assumed improved performance for systems using a supplemental fabric filter combined with activated carbon injection, these systems are expected to become the dominant compliance strategy in this case. However, because of the early stage of development of these technologies it is not possible at this time to tell whether they will be able to contribute significantly to meeting a 2008 cap.

In the Hg 5-ton case, electric power plants in all regions are expected to reduce Hg emissions substantially (Figure 9). The percentage change relative to the reference case in 2010 varies from 76 percent to nearly 100 percent among the regions. In terms of tonnage changes, the greatest reductions are expected in the regions with the largest reference case emissions, potentially leading to much lower Hg concentrations in the areas of greatest concern. To meet the 5-ton cap, significant reductions in Hg emissions will be needed at nearly all plants. In the Hg 20-ton case, the burden of reducing Hg emissions is not projected to be spread as evenly. The less stringent cap allows plants in some regions to reduce their Hg emissions by more or less than those in other regions. For example, excluding regions that produce 1 ton of Hg or less, the percentage change relative to the reference case in 2010 varies from 47 percent to 75 percent among the regions in the Hg 20-ton case.

Figure 9. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2010



Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M6008.D060801A. See Figure 26 in Chapter 4 for a map of electricity supply regions.

One important question with respect to reducing Hg emissions is whether they will be controlled with a cap and trade program, as assumed in the cases discussed previously, or whether maximum achievable control technology (MACT) standards will be set for each plant type. Because Hg is a hazardous air pollutant (HAP), a MACT approach may have to be used (under the provisions of the Clean Air Act) rather than a cap and trade approach. While a cap and trade program should allow power suppliers the flexibility to reduce their emissions at the lowest possible cost, there is concern that the reduction in Hg emissions under such an approach would not be uniform across the country, and that some areas would continue to have high Hg emissions. In this analysis, the Hg MACT 90% case assumes that all plants will be required to reduce Hg emissions from the coal they use by 90 percent, without trading of allowances.

The results in the Hg MACT 90% case are generally similar to those in the Hg 5-ton case; however, there are several key differences. Requiring all plants to reduce the amount of Hg in the coal they use by 90 percent would not achieve a 90-percent reduction in overall Hg emissions relative to the 1997 level. In the reference case, the total amount of Hg in the coal used is expected to grow from approximately 73 tons in 1999 to 83 tons in 2020. As a result, without any shift in coal use, requiring each plant to remove 90 percent of the Hg in the coal it used would lead to total national Hg emissions of 8 tons. The use of a MACT approach does not provide operators of coal-fired electric power plants with an incentive to switch to lower Hg coals, because they will have to remove 90 percent of the Hg regardless of the coal used. In addition, unlike with a specified national cap, a MACT program would also allow Hg emissions to grow over time if coal use grew. The projected Hg emissions in 2020 in the Hg MACT 90% case are 8 tons, 3 tons over the emission target in the Hg 5-ton case.

The electricity price impacts in the Hg MACT 90% case are lower than those in the Hg 5-ton case, but the regional pattern of Hg emission reductions is similar (Figure 10). For example, in 2010 the projected electricity price in the Hg MACT 90% case is 6.19 cents per kilowatthour, 0.8 percent above the reference case price and 3.0 percent below the price in the Hg 5-ton case. The price impacts are lower in the MACT case because there is no Hg emission allowance market and allowance costs do not impact the dispatch decisions for coal-fired plants. In addition, as explained earlier in this chapter, the Hg MACT 90% case does not achieve the 5-ton cap. The regional projections for Hg emissions suggest that, if reductions of 90 percent or more are required, there is likely to be little opportunity for overcompliance in some areas and undercompliance in others, whether or not trading is allowed.

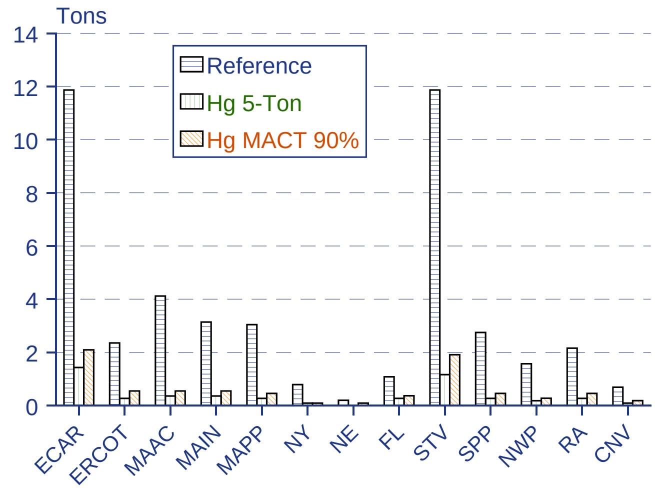
RPS Analysis

In the reference case, the use of renewable fuels to generate electricity is expected to increase slightly from 1999 to 2020. The Federal Government and some State governments have designed programs to spur renewable development, but they are not expected to lead to widespread use of renewables in the power sector. Although the cost and performance of new renewable generating technologies have improved, they still are not broadly competitive with fossil fuel technologies.

In the RPS 20% case, the 20-percent nonhydroelectric renewable fuel requirement is projected to lead to rapid development of new renewable technologies as it is phased in. With increased generation from nonhydroelectric renewables, generation from natural gas is projected to be lower than in the reference case (Figure 11 and Table 10). The key renewables for which increase are expected are biomass and wind (see Chapter 4).

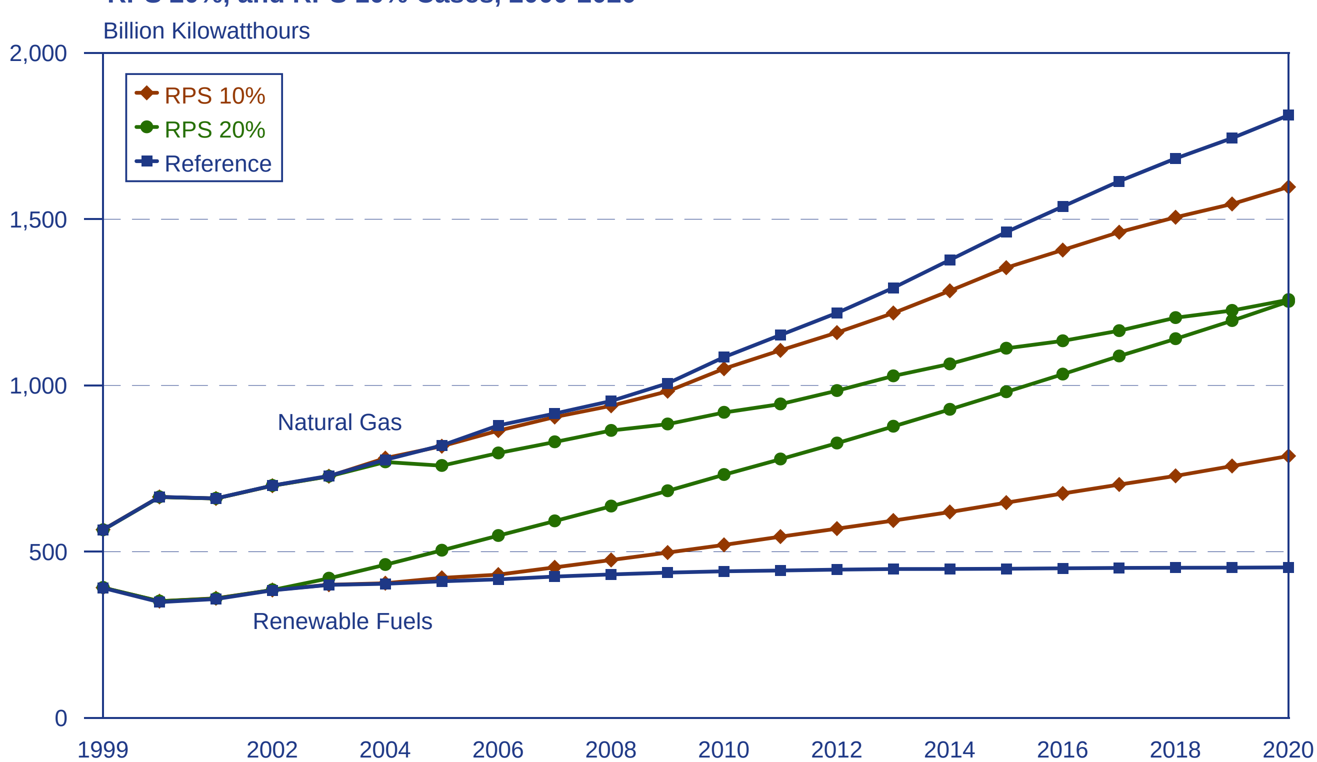
The development of the large amount of renewables that would be needed to satisfy the 20-percent RPS requirement has cost and price implications. Reaching the 20-percent target is expected to require increasing use of more expensive renewable options, and the renewable credit price (the subsidy needed to make nonhydroelectric renewables competitive) is expected to become quite high.[28] As the RPS is phased in, the renewable credit price is projected to increase to between 4 and 5 cents per kilowatthour from 2010 to 2020 (Figure 12).

Figure 10. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg MACT 90% Cases, 2010



Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M9008M.D060801A. See Figure 26 in Chapter 4 for a map of electricity supply regions.

Figure 11. Projected Electricity Generation from Natural Gas and Renewable Fuels in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

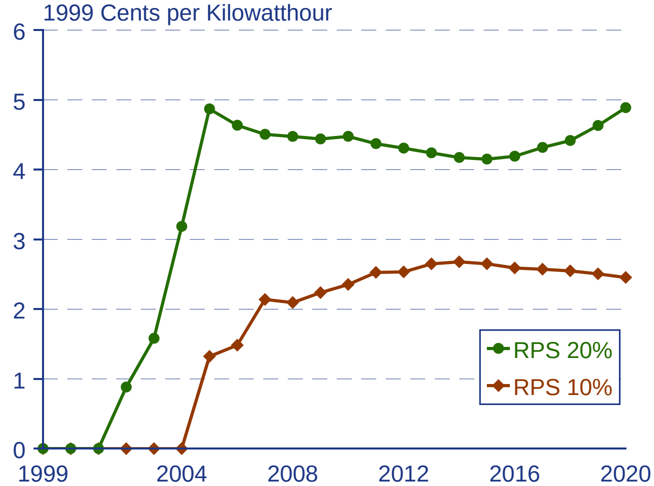
[28] Under an RPS, each seller of electricity is required to hold "credits" equivalent to the required percentage of sales from renewables. The credits, each representing 1 kilowatthour of generation from renewable fuels, can be sold by renewable generators to nonrenewable generators.

Natural gas prices are expected to decline as the use of renewable fuels increases. As a result, higher RPS credit prices are needed to keep renewable generating capacity competitive with new natural-gas-fired plants. Because each seller of electricity would only be required to hold credits equal to the required share of renewables (10 percent in 2010 and 20 percent in 2020), the impact on electricity prices is projected to be much smaller than the full price of the renewable credits. Lower natural gas prices due to reduced use by electricity generators also dampen the price increase. The price of electricity in the RPS case is expected to average 3 percent (about 0.2 cents) higher than in the reference case in 2010 and 4 percent higher in 2020.

The RPS 10% case shows the sensitivity of the projections to the required RPS share (Figure 13). The lower target for nonhydoelectric renewable generation reduces the need for power plant builders to develop more expensive renewable projects. As a result, electricity prices in the RPS 10% case are projected to be less than 1 percent higher than in the reference case.

The introduction of an RPS is projected to have only small impacts on SO_2, NO_x, and Hg emissions but a significant impact on CO_2 emissions, because the renewable plants added to meet the RPS would displace plants fueled with natural gas and, to a lesser extent, coal that would have been added without the RPS. Relative to the reference case, CO_2 emissions in 2020 are projected to be 56 million metric tons carbon equivalent (7 percent) lower in the RPS 10% case and 137 million metric tons

Figure 12. Projected Renewable Credit Prices in the RPS 20% and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2RPS20_X.D070601A and M2RPS20H_X.D070601A.

Table 10. Key Results for the Electricity Generation Sector in RPS Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Emissions (Tons)							
Hg	43	46	44	45	45	42	44
SO_2 (Millions)	12.7	9.7	9.7	9.7	8.9	8.9	8.9
NO_x (Millions)	5.7	4.3	4.2	4.3	4.5	4.1	4.4
CO_2[a]	556	693	638	677	777	640	721
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	170	176	241	147	190
NO_x (per Ton)	NA	4,391	4,516	4,451	5,037	5,625	5,491
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.33	6.17	6.21	6.47	6.22
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,157	2,250	2,366	2,090	2,246
Oil and Other	106	50	42	45	49	39	43
Natural Gas	593	1,085	919	1,051	1,813	1,258	1,597
Nuclear	734	725	725	725	613	613	613
Renewable	401	440	731	520	452	1,252	787
Total	3,728	4,597	4,573	4,591	5,294	5,252	5,286
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	6	6	15	10	10
SCR	0	93	97	94	93	100	94
SNCR	0	26	20	24	43	39	47

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

carbon equivalent (18 percent) lower in the RPS 20% case.

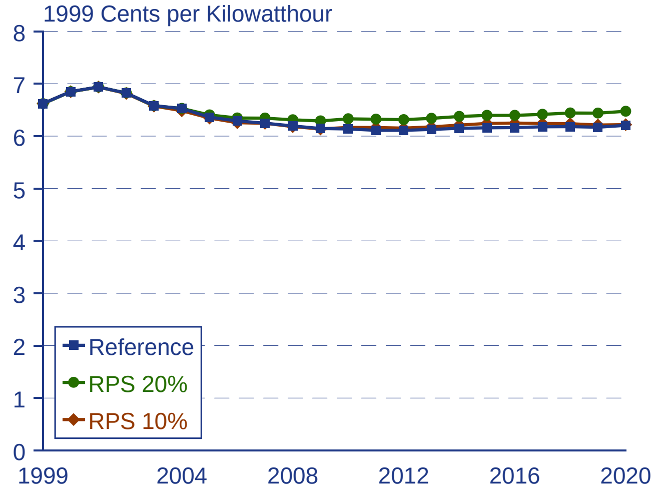
Analysis of CO_2 Caps

Unlike in the NO_x, SO_2, and Hg cases, the primary compliance strategy in the CO_2 1990-7% 2008 case is expected to be a major shift in the fuels used to produce electricity (Figure 14). To reduce CO_2 emissions to 7 percent below 1990 levels, power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewables. In addition, relative to the reference case, fewer nuclear plants are projected to be retired, consumers are expected to reduce their demand for electricity in response to higher electricity prices, and cogeneration capacity is expected to grow in response to higher grid-based electricity prices (Table 11).

Coal-fired generation in the CO_2 1990-7% 2008 case is projected to be 48 percent lower in 2010 and 56 percent lower in 2020 than in the reference case. Natural-gas-fired generation in the CO_2 1990-7% 2008 case is projected to be 61 percent higher than the reference case level in 2010 and 43 percent higher in 2020, and renewable generation is expected to be 27 percent higher in 2010 and 32 percent higher in 2020. Because 14 fewer gigawatts of nuclear capacity are expected to be retired in the CO_2 1990-7% 2008 case than in the reference case, nuclear generation is expected to be 3 percent higher in 2010 and 14 percent higher in 2020.

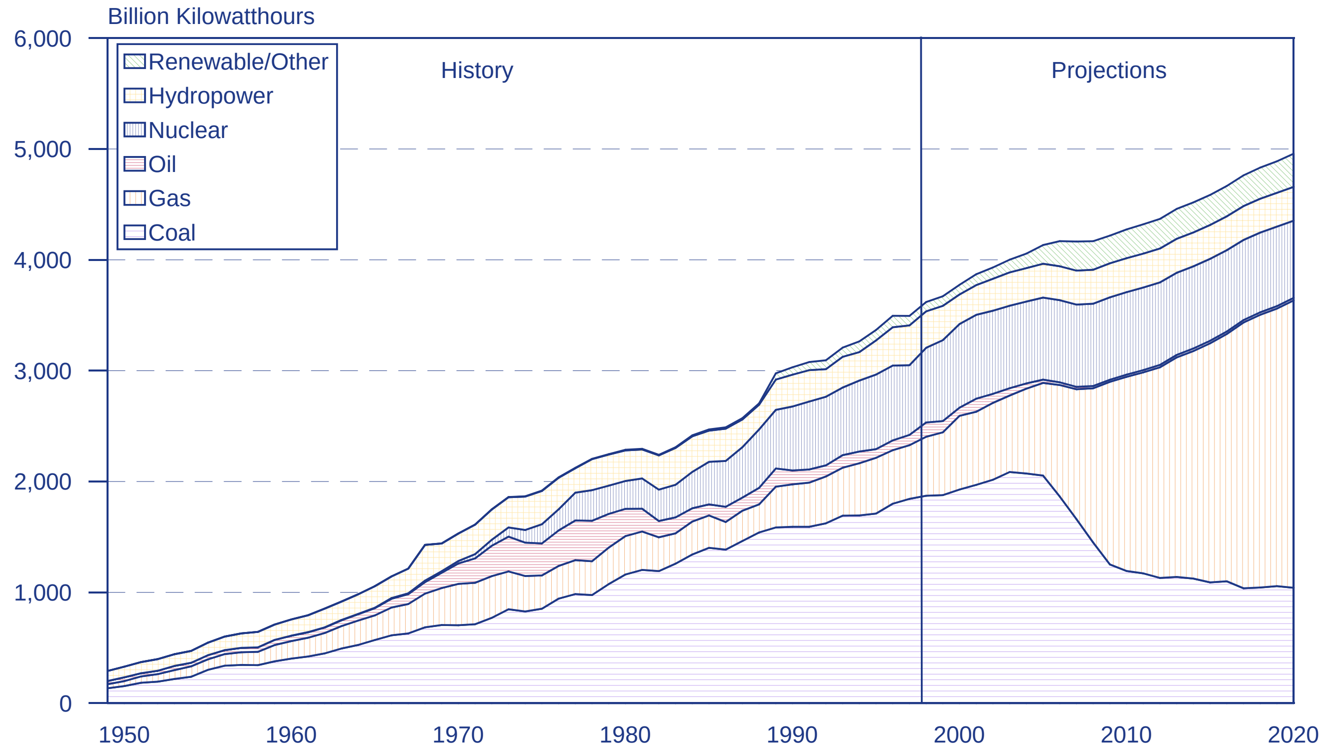
Consumers are expected to use less grid-based electricity in the CO_2 1990-7% 2008 case than in the reference case. In 2010, retail sales of electricity are expected to reach 3,803 billion kilowatthours in the CO_2 1990-7%

Figure 13. Projected Electricity Prices in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

Figure 14. Electricity Generation by Fuel, 1949-1999, and Projections for the CO_2 1990-7% 2008 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 M2C7B08.D060801A.

2008 case, 344 billion kilowatthours (8 percent) less than in the reference case. End users are also expected to consume more cogenerated power for their own use. For example, in 2010, total generation from cogenerators is expected to reach 331 billion kilowatthours, 70 billion kilowatthours (27 percent) above the reference case projection.

Increased cogeneration in the CO_2 1990-7% 2008 case is not projected to lead to higher CO_2 emissions outside the electricity sector. All other things being the same, the reduced use of coal in the electricity sector would be expected to lead to lower coal prices and increased use of coal in sectors of the economy not facing a CO_2 emissions cap. However, more than 90 percent of the coal consumed in the United States is used in the electricity generation sector, and most of the other sectors of the economy do not employ technologies that can use coal. As a result, the higher electricity and natural gas prices caused by efforts to reduce CO_2 emissions in the electricity sector is expected to dampen overall energy use outside the electricity sector and reduce energy-associated CO_2 emissions in the other sectors.

The increased use of natural gas in the power sector and its impact on natural gas prices, together with CO_2 allowance prices, are projected to lead to much higher electricity prices in the CO_2 1990-7% 2008 case than in the reference case. The wellhead price of natural gas is projected to reach $3.36 per thousand cubic feet in 2010 and $3.74 in 2020 in the CO_2 1990-7% 2008 case, compared with $2.87 and $3.22, respectively, in the reference case. CO_2 allowance prices in 2010 and 2020 are projected to be $157 and $151 per metric ton carbon equivalent, respectively, in the CO_2 cap case. It should be noted, however, that the projected NO_x and SO_2 allowance prices in the CO_2 1990-7% 2008 case are dramatically lower than those in the reference case, because efforts to reduce CO_2 emissions also reduce the need for investments to mitigate NO_x and SO_2 emissions. NO_x and SO_2 emissions in the CO_2 1990-7% 2008 case are projected to be 52 and 18 percent lower, respectively, than the reference case levels in 2020. In addition, efforts to reduce CO_2 lead to a 24-ton (53 percent) reduction in Hg emissions from the reference case level by 2020.

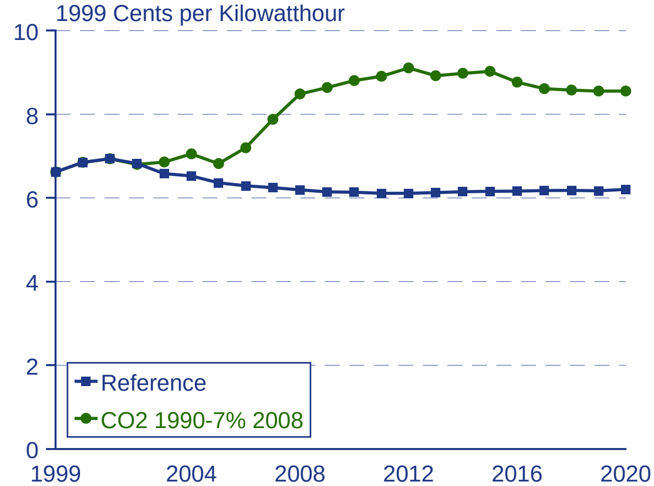
Table 11. Key Results for the Electricity Generation Sector in the CO_2 1990-7% 2008 Emission Cap Case, 2010 and 2020

Projection	1999	2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Emissions (Tons)					
Hg	43	46	24	45	21
SO_2 (Millions)	12.7	9.7	8.2	8.9	7.3
NO_x (Millions)	5.7	4.3	2.4	4.5	2.2
CO_2[a]	556	693	436	777	445
Allowance Prices (1999 Dollars)					
Hg (per Pound)	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	0	241	0
NO_x (per Ton)	NA	4,391	0	5,037	0
CO_2 (per Ton)[b]	NA	NA	157	NA	151
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	8.81	6.21	8.56
Generation by Fuel (Billion Kilowatthours)					
Coal	1,893	2,297	1,193	2,366	1,042
Oil and Other	106	50	32	49	37
Natural Gas	593	1,085	1,752	1,813	2,592
Nuclear	734	725	744	613	696
Renewable	401	440	558	452	595
Total	3,728	4,597	4,280	5,294	4,963
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)					
Scrubbers[c]	0	7	0	15	0
SCR	0	93	77	93	77
SNCR	0	26	36	43	37

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

Electricity prices are projected to be much higher in the CO_2 1990-7% 2008 case than in the reference case—43 percent higher in 2010 and 38 percent higher in 2020 (Figure 15). As a result, annual household electricity bills are projected to be $218 (23 percent) higher in 2010 and $173 (17 percent) higher in 2020, and the Nation's total electricity bill is projected to be $80 billion higher in 2010 and $63 billion higher in 2020 than in the reference case, despite expected reductions in consumer electricity use (8 percent lower in 2010 than projected in the reference case and 12 percent lower in 2020).

Figure 15. Projected Electricity Prices in the Reference and CO_2 1990-7% 2008 Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE. D060801A and M2C7B08.D060801A.

Analysis of Integrated Cases

Because actions taken by electricity producers to reduce NO_x, SO_2, CO_2, or Hg emissions—or to develop new renewable generators when an RPS is imposed—will affect the actions needed to meet the other emission caps or the RPS requirement, it is expected that integrated compliance decisions will be different from those targeted to any single requirement. In this analysis, six integrated cases incorporate different combinations of power sector emission caps on NO_x, SO_2, Hg, and CO_2, with and without an RPS (see Table 1 in Chapter 2), and three integrated sensitivity cases examine the effects of alternative assumptions on the results of the integrated cases (see Table 3 in Chapter 2). The key result in all the integrated cases is that when a cap on power sector CO_2 emissions is imposed, efforts to meet it also reduce the other emissions. The price and cost impacts in each of the integrated cases with a CO_2 cap are dominated by efforts to reduce CO_2 emissions (Table 12).

It should be noted, however, that when emission caps on NO_x, SO_2, CO_2, and Hg are assumed in various combinations, with and without an RPS, there are complex interactions among the compliance strategies and the resulting prices of emission allowances and electricity prices. The interactions can cause the impacts on resource costs and the impacts on electricity prices to move in opposite directions. For example, although resource costs are projected to be higher when caps are placed on all four emissions than when they are placed only on NO_x, SO_2, and CO_2, electricity prices are projected to be slightly lower. This occurs because the addition of an Hg cap raises the cost of continuing to operate existing coal-fired plants, leading to a reduction in the CO_2 allowance price that would be required to encourage power suppliers to retire coal-fired power plants and replace them with natural-gas-fired plants. Because the CO_2 allowance price would be included in the operating costs for all generating plants that use fossil fuels, a lower CO_2 allowance price would reduce the revenues of power suppliers in the cases with four emissions caps by lowering the costs of operating fossil plants and, thus, would lead to lower electricity prices.

Similarly, when an RPS is assumed to be combined with caps on NO_x, SO_2, CO_2, and Hg emissions, resource costs for generators complying with the caps are projected to be higher than when the RPS is not included. However, while electricity prices are projected to be well above reference case levels when NO_x, SO_2, CO_2, and Hg emissions are capped either with or without an RPS, they are projected to be lower in the long term when the RPS is included,[29] because increased dependence on renewables rather than natural gas would lead to lower prices for natural gas and for CO_2 allowances, offsetting the effects of the higher costs of renewable fuels on consumer electricity prices. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

Integrated Cases Reducing CO_2 Emissions to 1990 Levels

When power sector CO_2 emissions are assumed to be capped at the 1990 level in combination with various other emission caps, with or without an RPS, the key compliance strategy is projected to be a shift from coal to natural gas and, to a lesser extent, renewables (Figure 16). The results in the integrated cases with a CO_2 1990 cap are similar to those in the CO_2 1990-7% 2008 case but with smaller impacts because the CO_2 cap is less stringent. The role of renewables is especially important in cases that include an RPS. In addition, fewer nuclear

[29]In the early years of the forecast, electricity prices are projected to be higher in the case that combines an RPS with caps on NO_x, SO_2, CO_2, and Hg emissions than in the case that includes only the four emission caps.

Table 12. Key Results for the Electricity Generation Sector in Integrated Cases, 2010 and 2020

Analysis Case	Generation by Fuel (Billion Kilowatthours)			Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Allowance Prices (1999 Dollars)				Electricity Price (1999 Cents per Kilowatthour)	Electricity Sales (Billion Kilowatthours)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenue (Billion 1999 Dollars)
	Coal	Natural Gas	Renewable Fuels		CO_2[a] (per Ton)	NO_x (per Ton)	SO_2 (per Ton)	Hg (per Pound)				
2010												
Reference	2,297	1,085	436	2.87	NA	4,391	187	NA	6.14	4,147	944	255
Cases with CO_2 Emissions Capped at 1990 Level												
Integrated NO_X, SO_2, CO_2 1990	1,432	1,585	551	3.24	112	0	431	NA	8.13	3,873	1,108	315
Integrated NO_X, SO_2, $CO_2$1990, Hg	1,333	1,734	523	3.40	84	0	1	221,624	7.92	3,896	1,090	308
Integrated All CO_2 1990	1,471	1,344	762	2.97	84	0	3	216,210	8.01	3,882	1,097	311
Cases with CO_2 Emissions Capped at 1990-7% Level												
Integrated NO_X, SO_2, CO_2 1990-7%	1,189	1,780	551	3.50	142	0	246	NA	8.62	3,830	1,152	330
Integrated NO_X, SO_2, $CO_2$1990-7%, Hg	1,113	1,889	542	3.66	120	0	0	147,925	8.42	3,851	1,136	324
Integrated All CO_2 1990-7%	1,268	1,512	745	3.13	124	0	2	171,250	8.59	3,830	1,147	329
Integrated Sensitivity Cases												
Integrated Moderate Targets	1,539	1,456	572	3.09	111	0	43	55,507	8.18	3,870	1,109	316
Integrated Cost of Service	1,046	2,025	554	3.96	117	0	0	154,014	7.68	3,956	1,069	304
Integrated High Gas Price	1,124	1,838	553	4.08	125	0	0	152,337	8.60	3,838	1,152	330
2020												
Reference	2,366	1,813	448	3.22	NA	5,037	241	NA	6.21	4,788	1,005	297
Cases with CO_2 Emissions Capped at 1990 Level												
Integrated NO_X, SO_2, CO_2 1990	1,136	2,571	572	3.69	143	0	436	NA	8.41	4,291	1,177	361
Integrated NO_X, SO_2, $CO_2$1990, Hg	1,124	2,584	561	3.72	135	0	2	148,278	8.36	4,309	1,172	360
Integrated All CO_2 1990	1,390	1,784	1,178	3.09	71	1,304	150	203,663	7.82	4,354	1,127	340
Cases with CO_2 Emissions Capped at 1990-7% Level												
Integrated NO_X, SO_2, CO_2 1990-7%	1,013	2,605	611	3.80	154	0	259	NA	8.63	4,218	1,185	364
Integrated NO_X, SO_2, $CO_2$1990-7%, Hg	1,032	2,608	602	3.74	150	0	1	109,636	8.55	4,257	1,182	364
Integrated All CO_2 1990-7%	1,235	1,909	1,176	3.31	90	1,118	0	168,463	7.98	4,313	1,142	344
Integrated Sensitivity Cases												
Integrated Moderate Targets	1,413	2,138	755	3.74	119	0	30	45,114	8.19	4,318	1,158	354
Integrated Cost of Service	894	2,719	705	4.15	162	0	0	121,781	7.86	4,453	1,126	350
Integrated High Gas Price	1,082	2,098	735	5.05	169	0	2	171,790	9.27	4,188	1,237	388

[a]1999 dollars per metric ton carbon equivalent.

NA = not applicable.

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

plants are expected to be retired than in the cases without CO_2 caps, and consumers are expected to reduce electricity consumption in response to higher electricity prices. As in the CO_2 1990-7% 2008 case, reduced electricity usage by consumers and increased cogeneration also play a role.

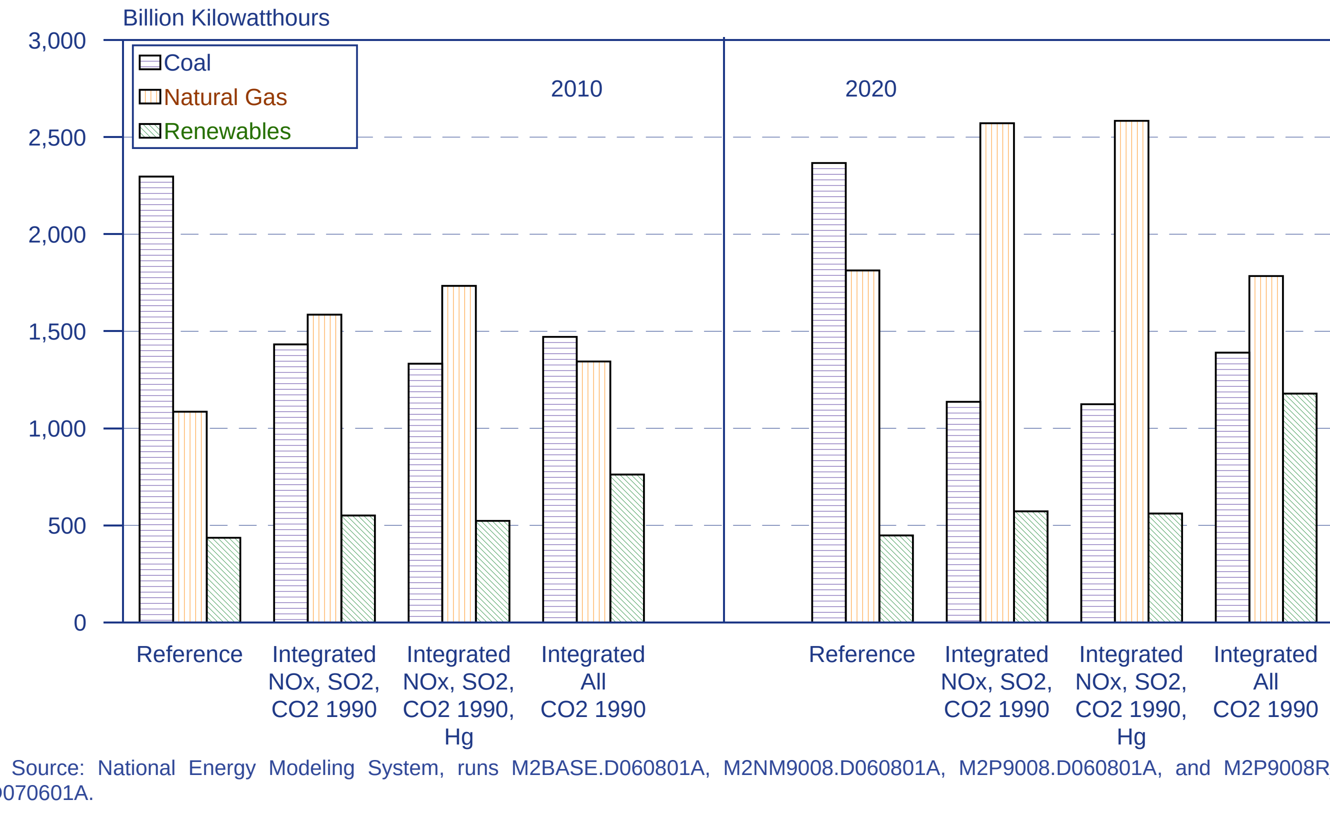
Relative to the reference case, coal-fired generation in 2010 is expected to be between 38 and 42 percent lower in the integrated NO_x, SO_2, CO_2 1990 and integrated NO_x, SO_2, CO_2 1990, Hg cases. The inclusion of an RPS, as in the integrated all CO_2 1990 case, leads to higher projections for coal-fired electricity generation than would otherwise be expected in a case with a CO_2 cap. For example, in 2010, coal-fired generation in the integrated all CO_2 1990 case is projected to be 1,471 billion kilowatthours, 10.4 percent above the level projected in the integrated NO_x, SO_2, CO_2 1990, Hg case. Under an RPS, the forced penetration of renewables that produce no CO_2 eases the pressure on power suppliers to reduce their use of coal to comply with the CO_2 cap.

The situation for natural-gas-fired generation is projected to be the opposite of that for coal—reducing power sector CO_2 emissions means increasing natural gas use. Relative to the reference case, natural-gas-fired generation in 2010 is projected to be 46 percent higher in the integrated NO_x, SO_2, CO_2 1990 case and 60 percent higher in the integrated NO_x, SO_2, CO_2 1990, Hg case. In the integrated all CO_2 1990 case, the role of increased gas use in reducing CO_2 emissions is dampened somewhat by the penetration of renewables. The renewables added to comply with the RPS reduce the need for power suppliers to add natural gas plants to displace coal plants.

Electricity generation from renewable fuels is also expected to be higher in integrated cases with a CO_2 emission cap. For example, in the integrated NO_x, SO_2, CO_2 1990 case, renewable generation in 2010 is projected to reach 551 billion kilowatthours, 115 billion kilowatthours (26 percent) higher than in the reference case. The penetration of renewables is sensitive to both the price of natural gas and the price of CO_2 allowances. Although wellhead natural gas prices are projected to be higher in the integrated NO_x, SO_2, CO_2 1990, Hg case than in the integrated NO_x, SO_2, CO_2 1990 case—which would tend to make renewables more attractive—the CO_2 allowance price is projected to be lower, leading to lower renewable penetration.

The increased dependence on natural gas and renewables to reduce power sector CO_2 emissions is expected to have implications for emissions allowance prices, electricity prices, and generating costs. In cases that combine a CO_2 emission cap with NO_x, SO_2, and / or Hg emission caps, the industry's efforts to comply with the CO_2 cap lead to much lower allowance prices for NO_x, SO_2, and Hg, because the reduction in coal use lessens the need for investments to reduce NO_x, SO_2, and Hg emissions. For example, in the integrated NO_x, SO_2, CO_2

Figure 16. Projected Electricity Generation from Coal, Natural Gas, and Renewable Fuels in the Reference and Integrated CO_2 1990 Cases, 2010 and 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, and M2P9008R_X.D070601A.

1990, Hg case, the SO_2 allowance price in 2010 is projected to be nearly zero, as compared with $794 per ton in the SO_2 2008 case, which assumes the same cap on SO_2 emissions. Also, as shown in the CO_2 1990-7% 2008 case, controlling power sector CO_2 emissions alone is expected to lead to Hg emissions in 2010 that are 53 percent lower than in the reference case.

A similar change is projected for NO_x allowance prices. In the later years of the projections in the integrated NO_x, SO_2, CO_2 1990, Hg case, the NO_x allowance price is well below the price in the NO_x 2008 case, because some of the control equipment that would be added to reduce NO_x emissions is unnecessary when coal use is reduced. When an RPS is combined with caps on NO_x, SO_2, and Hg, there is less pressure to reduce coal use for electricity generation. As a result, the projected prices of NO_x, SO_2, and Hg allowances are higher in the integrated all CO_2 1990 case than in the integrated NO_x, SO_2, CO_2 1990, Hg case.

In the three integrated cases that assume a CO_2 emissions cap at the 1990 level, the expected shift to natural gas and renewables for power generation, combined with investments made to reduce NO_x, SO_2, and Hg emissions and the costs of holding emissions allowances is projected to lead to higher electricity prices and production costs. The price of electricity in 2010 is projected to range between 7.92 and 8.13 cents per kilowatthour in the three cases—between 29 percent and 32 percent higher than projected in the reference case. Prices are slightly lower in the integrated NO_x, SO_2, CO_2 1990, Hg case than in the integrated NO_x, SO_2, CO_2 1990 case, because the cap on Hg emissions makes existing coal-fired plants less economically attractive and reduces the CO_2 allowance price required to stimulate a shift from coal to natural gas. Total revenues for the power generation industry in 2010 in the three integrated CO_2 1990 cap cases are projected to be between $54 billion and $60 billion over the reference case level. For the average household this translates into an annual electricity bill that is between $145 and $163 higher than projected in the reference case in 2010.

The addition of the RPS to caps on NO_x, SO_2, CO_2, and Hg emissions is projected to increase the resource costs of compliance faced by power suppliers from what they would be without the RPS requirement. However, the electricity price projections in the integrated all CO_2 1990 case, which includes a 20-percent RPS requirement, are lower than those in the integrated NO_x, SO_2, CO_2 1990, Hg case in later years, because the price impact of higher cost renewables is offset by lower gas prices and lower CO_2 allowance prices. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher. In other words, increased reliance on renewables in the integrated all CO_2 1990 case leads to smaller increases in natural gas prices and CO_2 allowance prices. Although electricity prices are similar in the integrated cases with and without the RPS, the resource costs are higher in the case with the RPS (Figure 17).

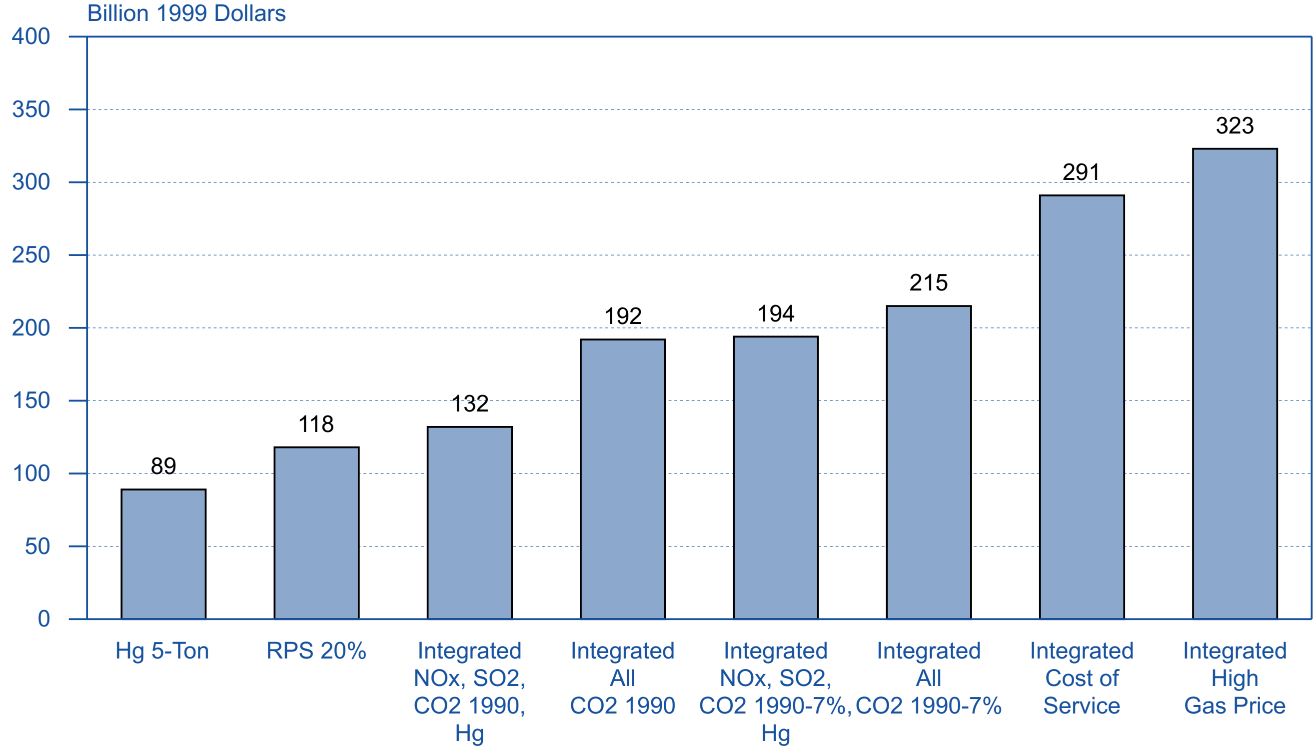
Because the decisions made to control one emission—particularly, decisions made to reduce CO_2 emissions—affect the other emissions, the timing or sequencing of the control programs could be important. When facing requirements to reduce multiple emissions, power suppliers will attempt to choose a strategy that allows them to meet all the requirements most economically. They will attempt to take account of the sequencing and timing (provided that they are known) of the various emission reduction requirements. As shown in this analysis, if the emissions reduction programs for NO_x, SO_2, Hg, and CO_2 were on the same timetable, power suppliers would be expected to retire a large number of existing coal-fired plants to reduce CO_2 emissions and forgo installing emissions control equipment to reduce NO_x, SO_2, and Hg emissions. If, on the other hand, they were required to reduce NO_x, SO_2, and Hg emissions before reducing CO_2 emissions, larger investments in NO_x, SO_2, and Hg emissions control equipment might make economic sense.

Integrated Cases Reducing CO_2 Emissions to 7 Percent Below the 1990 Level

The results in the integrated cases that cap power sector CO_2 emissions at 7 percent below the 1990 level essentially parallel those in the cases that cap them at the 1990 level. As in those cases, the key compliance strategy is a shift from coal to natural gas and renewables combined with fewer nuclear plant retirements and reduced consumer electricity use. Relative to the cases with power sector emissions capped at the 1990 level, the shift out of coal, reliance on renewables, CO_2 allowance prices, and electricity prices all are higher in the cases with CO_2 emissions capped at the 1990-7% level.

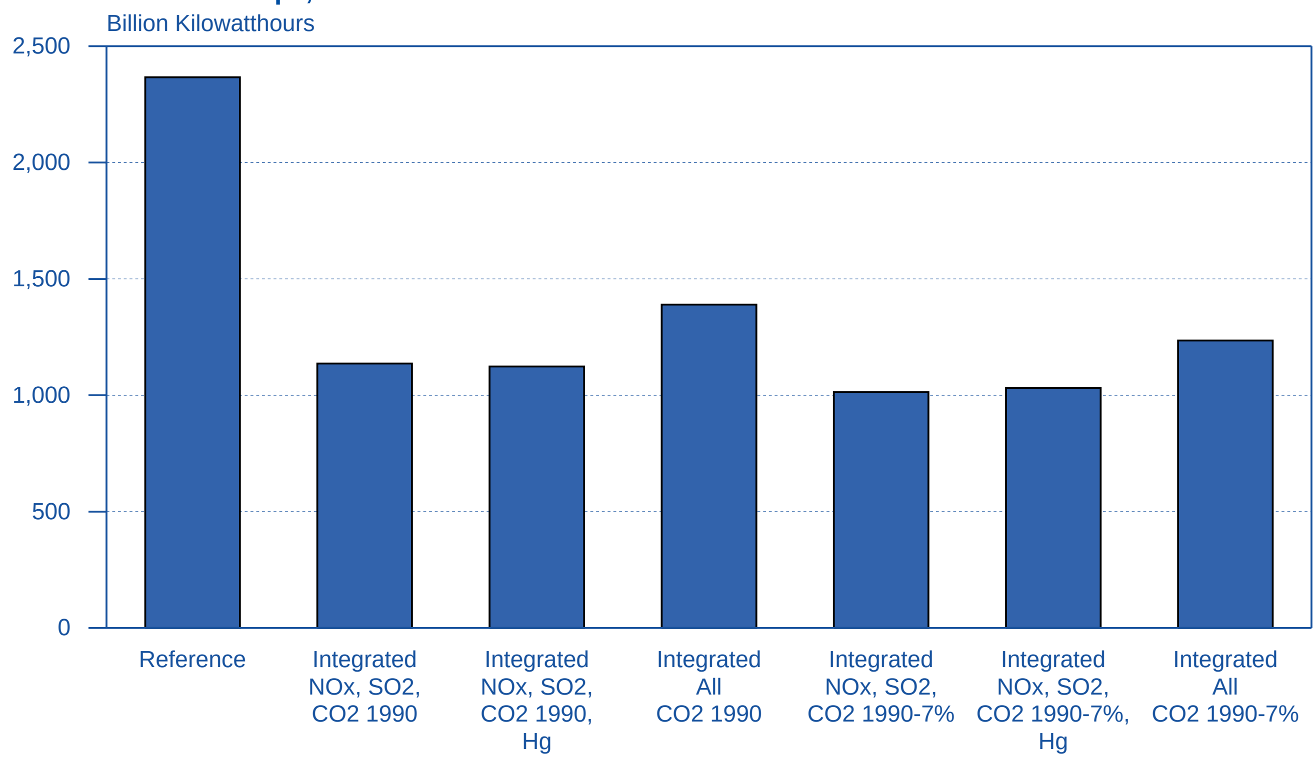
Figure 18 compares the projected coal generation in 2020 in the cases with CO_2 emissions capped at the 1990 level with those capped at the 1990-7% level. Among the comparable cases the coal generation in 2020 is between 8 percent and 11 percent lower in the cases with the more stringent CO_2 cap. Note that projected coal generation is higher in the cases that include an RPS requirement—the integrated all CO_2 1990 and integrated all CO_2 1990-7% cases. The penetration of carbon-free renewables stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 emission caps. Conversely, renewable generation is significantly higher in the case with a more stringent CO_2 cap and no RPS (Figure 19). In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, total renewable generation reaches 16.1 percent of sales in

Figure 17. Cumulative Resource Costs for Electricity Production, 2001-2020: Differences from Reference Case Projection in Selected Cases



Source: National Energy Modeling System, runs M2BASE.D080401A, M2M9008.D080401A, M2P9008.D080401A, M2RPS20.D080401A, M2P9008R.D080401A, M2P7B08.D080401A, M2P7B08R.D080401A, M2P7B08L.D080401A, and M2P7B08C.D080401A.

Figure 18. Projected Coal-Fired Electricity Generation in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

2020, while nonhydroelectric renewable generation (the facilities that qualify for the RPS) reaches 6.6 percent of sales. Although this amount is still far below the 20-percent level required in the cases with an RPS, it illustrates that meeting a power sector CO_2 cap set at 7 percent below the 1990 level could stimulate additional renewable development.

CO_2 allowance prices, natural gas prices, and electricity prices all are projected to be higher in the cases with a CO_2 emission cap of 7 percent below the 1990 level than they are in the cases with the less stringent CO_2 cap. For example, in 2010 CO_2 allowance prices are projected to be $120 per metric ton carbon equivalent in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, $36 (43 percent) above the level in the comparable case with the CO_2 cap set at the 1990 level (see Table 12). At the same time, electricity prices are projected to be 8.42 cents per kilowatthour (6 percent) above the level in the comparable case with the CO_2 cap set at the 1990 level and 2.28 cents per kilowatthour (37 percent) above the reference case level (Figure 20).

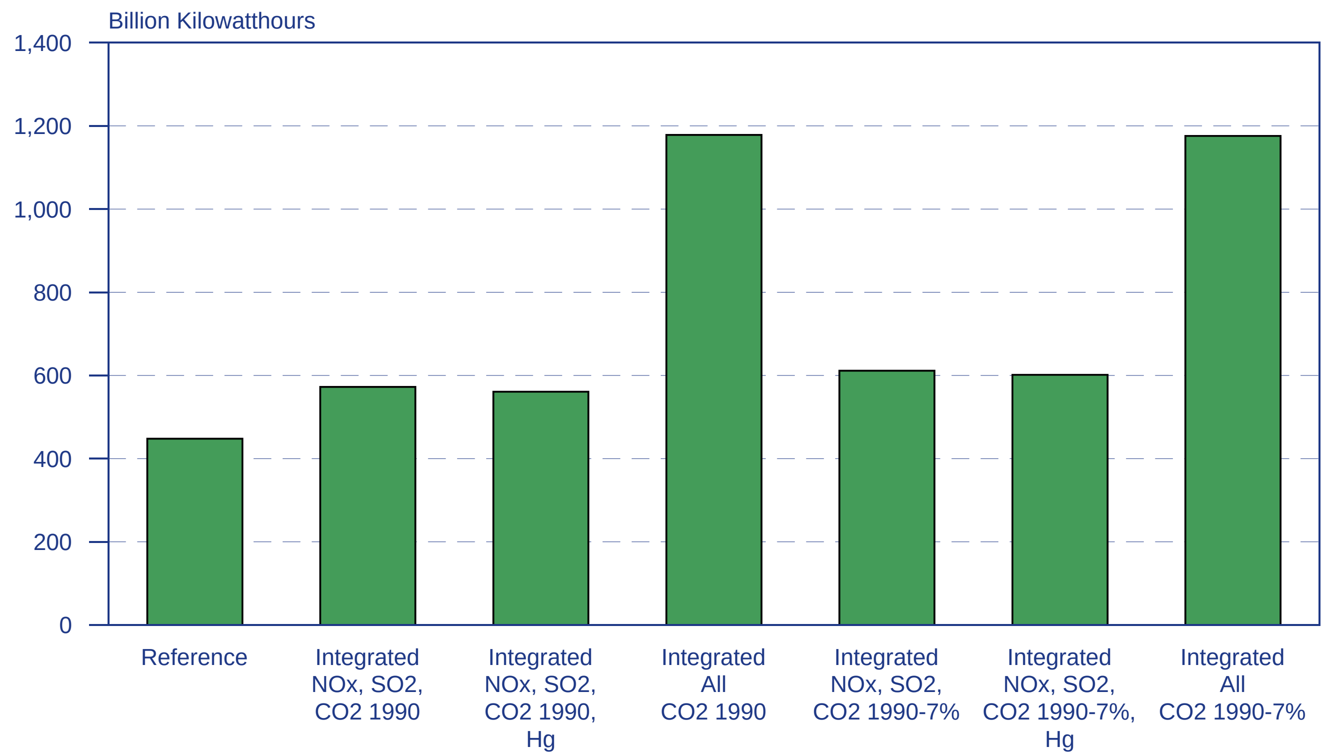
The addition of the RPS to caps on NO_x, SO_2, CO_2, and Hg emissions is projected to increase the resource costs of compliance faced by power suppliers by $21 billion over the 2000 to 2020 time period from what it would be without the RPS requirement. However, as with CO_2 1990 cap cases, electricity prices in the later years of the integrated NO_x, SO_2, CO_2 1990-7%, Hg case are higher than in the integrated case with an RPS requirement. Forcing in renewables with the RPS leads to lower natural gas prices and, in turn, lower electricity prices. The average price of natural gas delivered to electricity producers in 2020 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case is $4.49 per thousand cubic feet, $0.56 (14 percent) higher than in the comparable case with an RPS. And with increased investment in more expensive renewable generators, resource costs are higher in the integrated case with an RPS. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

Integrated Sensitivity Cases

Many factors influence the results of the model projections presented in this analysis. Sensitivity cases are employed to illustrate the potential impacts of three key areas of importance—the levels of the emission caps chosen, the pricing of electricity in regulated regions, and natural gas prices.

In the integrated moderate targets case, the caps on NO_x, SO_2, CO_2, and Hg emissions and the RPS are all less stringent than in the integrated all CO_2 1990-7% case

Figure 19. Projected Electricity Generation from Renewable Fuels in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

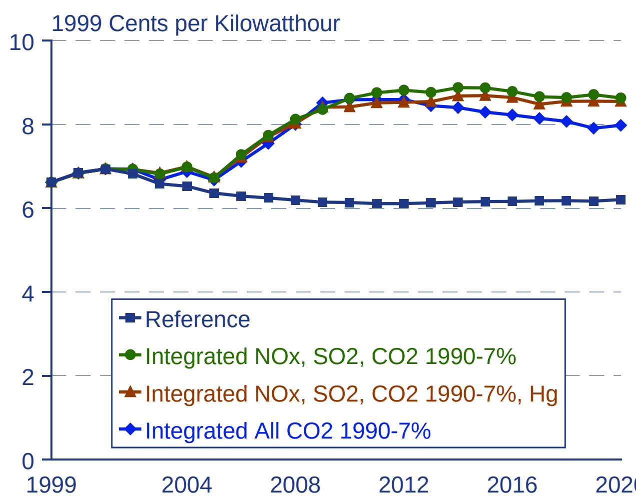
(see Tables 2 and 4 in Chapter 2). The reduced stringency of this case leads to lower allowance and electricity prices, especially in the early years of the projections (Figure 21). For example, in 2010 CO_2 allowance prices are projected to be $111 per metric ton carbon equivalent in the integrated moderate targets case, $13 (10 percent) lower than in the comparable integrated all CO_2 1990-7% case. Electricity prices are also much lower, reaching only 8.18 cents per kilowatthour in 2010, compared with 8.59 cents per kilowatthour in the integrated all CO_2 1990-7% case. By 2020 the electricity prices projected in the two cases are similar, because the more stringent RPS in the integrated all CO_2 1990-7% case leads to lower natural gas prices in 2020. As in other cases with a CO_2 cap, the key compliance strategy for electricity producers is expected to be a shift from coal to natural gas and renewables.

The integrated cost of service case assumes that emission allowances in regions of the country that remain under regulated pricing will be treated as having zero cost and not reflected in electricity prices (see Chapter 2 for a description of regional pricing). This case does not include an RPS. The resulting projections show lower electricity prices in regulated regions but higher prices in competitive regions than are projected in the comparable integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Resource costs are higher in the sensitivity case, because consumers are not expected to reduce their electricity usage by as much, and power suppliers are therefore projected to take additional actions to reduce emissions. Relative to the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, demand for electricity is projected to be higher, natural gas prices are higher, and reliance on renewables is greater. Electricity prices in the integrated cost of service case in 2010 are projected to be 25 percent higher than in the reference case but 9 percent lower than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Total resource costs are projected to be 4 percent higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

In the integrated high gas price case (with no RPS), it is assumed that improvements in the technologies associated with the discovery, development, and delivery of natural gas are not as robust as in the reference and other cases. The change in assumptions in this case is not meant to represent an expectation but, rather, to demonstrate the sensitivity of the results to higher natural gas prices. While the main compliance strategy remains a switch from coal to natural gas and renewables, electricity prices and resource costs are projected to be higher and reliance on renewables greater. In addition, because of higher natural gas and electricity prices, consumers are projected to play a larger role in reducing emissions by lowering their use of natural gas and electricity.

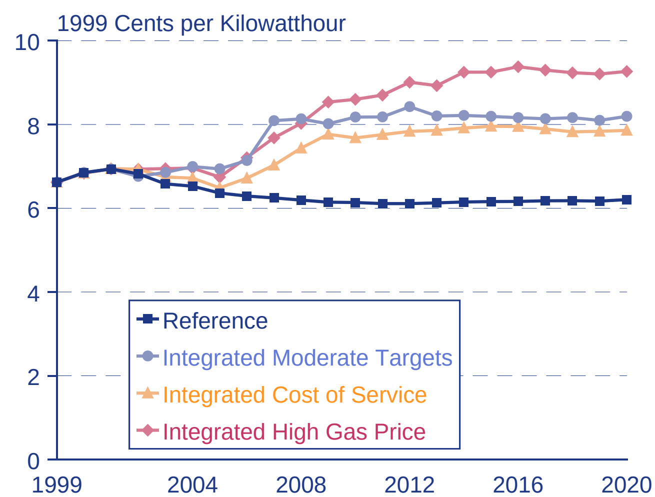
For example, the price of electricity in 2020 in the integrated high gas price case is projected to be 9.27 cents per kilowatthour—49 percent higher than in the reference case and 8 percent higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, which incorporates the same natural gas technology assumptions as the reference case. By 2020, the share of generation coming from all renewables is projected to be 18 percent in the integrated high gas price, 9 percentage points higher than projected in the reference case and 4 percentage points higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. On the other hand, consumers are projected to use 13 percent less electricity in 2020 in the integrated high gas price case than in the reference case.

Figure 20. Projected Electricity Prices in the Reference Case and Integrated Cases with 1990-7% CO_2 Emission Caps, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

Figure 21. Projected Electricity Prices in the Reference Case and Integrated Sensitivity Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

Summary and Uncertainties

In cases without a CO_2 emission cap, the key strategy for reducing emissions to the target caps is expected to be the addition of emissions control equipment. The equipment includes scrubbers to reduce SO_2 and Hg emissions, SCR and SNCR equipment to reduce NO_x (SCRs with scrubbers also enhance Hg removal), and ACI equipment to reduce Hg. Switching to lower sulfur and lower Hg coal and reducing overall coal use is projected to play a fairly small role. The electricity price and cost impacts in these cases are not expected to be large, generally within a few percent of the prices seen in the reference case. The resource cost impacts are generally larger than the electricity price impacts in these cases, indicating that coal plant operators are projected to have to absorb some of the costs of compliance rather than pass them on to consumers.

In cases with a CO_2 emission cap, the key strategy for meeting the cap is a shift from coal to natural gas and renewables (particularly in cases with an RPS). The continued use of existing nuclear units and lower consumer electricity use in response to higher electricity prices also play a role. When an RPS is assumed with a CO_2 cap, the projected reduction in coal use is not quite as large as when an RPS is not included. In cases in which the CO_2 cap is set at 7 percent below the 1990 level, electricity generation from coal in 2020 is projected to be around 56 percent lower than in the reference case. When a 20-percent RPS is included, the reduction in coal-fired generation is not as large, at around 48 percent below the reference case level in 2020.

The electricity price and cost impacts in cases with a CO_2 emission cap are much larger than in those without a CO_2 emission cap. With caps on NO_x and SO_2 emissions set to 75 percent below their 1997 levels, an Hg cap set to 90 percent below 1997, and a CO_2 cap set to 7 percent below 1990, the price of electricity is projected to be 37 percent higher than the reference case level in 2010 and 38 percent higher in 2020. For the average household, annual electricity bills are expected to be $192 and $177 (20 and 18 percent) higher in 2010 and 2020, respectively. Total revenues for the power generation industry are projected to be $69 billion and $67 billion higher than the reference case projections in 2010 and 2020, respectively.

In contrast to the cases without a CO_2 emission cap, the resource cost impacts in the CO_2 cap cases are typically much smaller than the electricity price impacts. Because there are no economical CO_2 removal and storage technologies, the costs of CO_2 allowances fall on all fossil generators, and coal-fired plants, with their high allowance costs, often set the market-clearing price for electricity. Owners of plants that have relatively low CO_2 emissions—i.e., existing renewable, nuclear, and efficient natural gas units—could see large increases in profits in cases with CO_2 caps if they are allowed to sell power at market rates.

As with any 20-year projection there is considerable uncertainty about the results presented here. This is particularly true for the projections concerning Hg emissions control. As stated in Chapter 2, while a substantial amount of data about Hg emissions from coal plants has been collected in recent years, considerable uncertainty still remains about the measurement and control of Hg emissions. Numerous efforts are underway to test various removal technologies, but no full-scale tests have been carried out at this point. It is possible that new, innovative technologies will be developed that significantly lower the costs of Hg removal. The Hg technology sensitivity cases presented in this report are meant to illustrate the potential impact of successful technological breakthroughs. However, it is also possible that it may be very difficult to control all coal plant types to the required level—particularly in scenarios that call for a 5-ton cap or 90 percent removal at each plant.

In the cases with a CO_2 emission cap, uncertainty exists about the ability of the power sector to move rapidly from dependence mostly on coal to dependence on natural gas and renewables. Coal-fired power plants currently account for more than one-half of the electricity produced in the United States. Although the share produced by natural gas plants is projected to grow over the next 20 years as demand for electricity grows, it is unclear whether it could also take over a large part of the market now occupied by coal at the same time. The amount of power plant construction needed to replace retiring coal plants would present a serious challenge. In addition, recent history suggests that care would have to be taken to ensure that natural gas resources were developed rapidly to avoid price shocks. The integrated case with high natural gas prices illustrates the sensitivity of the projections to natural gas price assumptions.

In regard to nonhydroelectric renewables, the amount projected to be developed, particularly in those cases with an RPS, would multiply existing capacity by 16 times by 2020. Although total resource estimates suggest that there are considerable wind, biomass, and geothermal energy supplies in the United States, the technical and economic feasibility of developing the amount called for in these cases is not fully known. It is expected that the cost and performance of new renewable generating technologies stimulated by an RPS or the need to reduce CO_2 emissions would improve as they penetrated the market, but it is unclear that such technological improvement could offset the need to develop more expensive resources.

Careful planning would be needed in all cases to ensure the reliability of the electricity system during the transition period. In cases without a CO_2 cap, system reliability could be at risk during the period when a large amount of emissions control equipment is added. In many instances, plants must be taken out of service when final connections for emissions control equipment are made. If extended outages resulted or power suppliers did not coordinate their outages, the reliability of the system could fall, increasing the potential for price volatility.

In addition, in this analysis, new generating capacity is assumed to be built as needed to meet customer demand and maintain reliability in all years and regions. While this assumption is reasonable in the long run, it is not meant to capture the potential for market problems in the short run. For example, if the demand for electricity grew more rapidly than expected over the next few years or there were delays in the siting and permitting of needed new plants, the additional requirement to take a large amount of capacity out of service to add emissions control equipment could exacerbate a tight market situation, leading to larger near-term price impacts than are shown in this analysis.

Lastly, the electricity generation system in the United States is currently undergoing significant change—moving from a long period of average cost regulated prices to one in which power prices are expected to be set by market forces. It is unclear at this time how new competitive pricing practices—real-time rates, congestion charges, etc.—might influence consumer responses to the electricity price changes projected in this report. The exact form that each of the regional markets will take is not known at this time. Care will have to be taken to ensure that the policy instruments designed to reduce emissions will operate well within them. Each of the various policy instruments available—technology standards, emission taxes, cap and trade systems of various forms—would have different impacts on electricity prices and resource costs.

4. Fuel Market and Macroeconomic Impacts

Introduction

Efforts to reduce multiple emissions from electric power plants are expected to affect fuel choice decisions in the electricity generation sector, with significant impacts on supply patterns, prices, and employment in the coal, natural gas, and renewable fuels markets. This chapter discusses the projected impacts of new emission caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury (Hg) and the adoption of a renewable portfolio standard (RPS) on the U.S. markets for those fuels, including industry employment levels. The chapter concludes with a discussion of the projected impacts on the U.S. economy as a whole resulting from the changes in energy prices that would be expected in various scenarios.

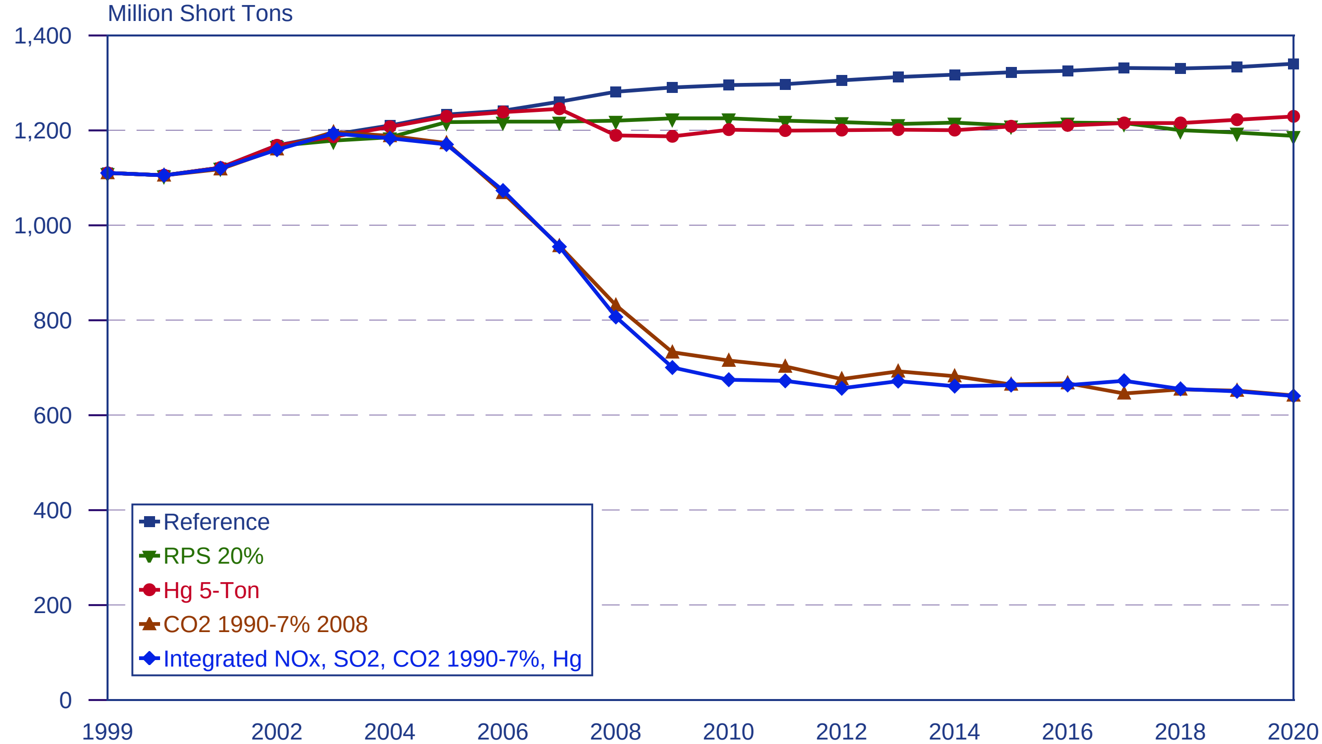
Coal Markets

The imposition of new, more stringent emission caps on electricity power plants would affect coal consumption, national and regional production, and prices (Figure 22). In general, the revised caps and the consequent need for introducing control technologies and other measures necessary to achieve compliance with the caps would raise the cost of electricity from coal-fired power plants relative to those using other fuels, encourage fuel switching, and cause the level of coal-fired generation to be reduced. The impacts on national coal industry production levels are projected to be negative relative to the reference case. The overall impacts on coal production depend on both the extent of the projected decline in coal demand and the types of coal expected to be used in the future mix of coal-burning capacity.

NO_x 2008 and SO_2 2008 Cases

In the NO_x 2008 case, the additional cost of adding and operating post-combustion emission control equipment is projected to increase electricity prices slightly and reduce electricity sales by a small amount. The projected coal share of the generation market and total projected coal-fired generation in the NO_x 2008 case are essentially unchanged from the reference case projections for 2020. Minemouth coal prices in the NO_x 2008 case range from 9 to 32 cents per ton higher than prices in the reference case for most of the 2008-2020 period (Table 13).

Figure 22. Projected U.S. Coal Production, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, M2M9008.D060801A, M2C7B08.D060801A, and M2P7B08.D060801A.

Sustained growth in electricity demand over the forecast period is projected in the SO_2 2008 case. Although some additional coal-fired plants are projected to be retired, highly efficient, low-emitting advanced coal technology units are projected to be placed into service. In the SO_2 2008 case, the more stringent SO_2 emission caps are expected to lead to approximately 139 gigawatts of scrubber retrofits, compared with about 15 gigawatts in the reference case. Coal production east of the Mississippi River is projected to decline slowly but gain market share relative to the reference case. Eastern coal has a relatively high energy content, which permits greater generation of electricity per ton of coal burned.

Hg Emission Reduction Cases

The Hg emission reduction cases examine the impacts of reducing power plant emissions of Hg substantially below the 1997 emission level. Virtually all Hg emissions in the electricity generation sector originate from coal-fired boilers. Three general options are available to current coal-burning electricity generators to reduce Hg emissions: switch to coal containing lower quantities of Hg per unit of delivered energy input; install and utilize technologies that reduce Hg emissions; and dispatch coal-fired units at reduced levels or retire them from service, replacing the loss in output with power generation from other fuels. For a given Hg emission target, the extent to which each approach is expected to be utilized depends on the degree to which greater use of low-Hg coal types will increase their delivered costs, the cost and effectiveness of available Hg removal technologies, and the costs associated with replacement of coal-fired generation by other generation sources.

In the Hg 5-ton case and the Hg 20-ton case, both cap and trade cases, there is a projected shift to coal sources (such as the Rocky Mountain region) that contain lower levels of Hg and a move away from sources (such as lignite in the Gulf region) that have higher Hg content. Scrubber retrofits are expected to be made at a rapid pace in the Hg 5-ton case, reaching 18 gigawatts in 2010 and 52 gigawatts in 2020, compared with 15 gigawatts in 2020 for the reference case (Table 14). Scrubbers are introduced at a rapid pace through 2010 in the Hg 20-ton case, and activated carbon injection (ACI) controls, spray cooling, and fabric filters are also added, in order to meet the 20-ton target for Hg emissions. Because of the scrubbers, the Hg 20-ton case in 2010 makes greater use of eastern coal, which has a higher minemouth price. After 2010, Hg emissions are projected to be kept under the cap by employing additional ACI Hg removal, as coal-fired generation increases. In the Hg 5-ton case, ACI controls are heavily employed through 2010, along with scrubbers. After 2010, additional requirements for Hg removal are expected to be met by adding scrubbers. The steps taken to reduce Hg emissions, including switching to coals with lower Hg content, add to the cost of coal-fired generation and reduce coal consumption in the generation sector by a projected 116 million tons in 2020 in the Hg 5-ton case, relative to the reference case.

In the Hg MACT 90% case, each coal-burning generating unit is required to install a set of emission control technologies that will achieve (at a minimum) a 90-percent reduction in Hg emissions from the coal used at the plant. In this case, coal-fired generation drops by 1 percent in 2020 relative to the reference case. Generators are projected to meet the MACT requirements by installing control technologies rather than switching to coals with lower Hg content.

Most of the raw coal produced in the United States undergoes some degree of processing or coal preparation before it is shipped to generators, in order to remove associated rock and clay from the coal and make it a more marketable product. Generally, such processing will remove some of the Hg and sulfur in the raw coal as

Table 13. Coal Market Projections in the NO_x 2008 and SO_2 2008 Cases, 2010 and 2020

Projection	1999	2010 Reference Case	2010 NO_x 2008 Case	2010 SO_2 2008 Case	2020 Reference Case	2020 NO_x 2008 Case	2020 SO_2 2008 Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,129	1,117	1,196	1,181	1,185
Total Coal Production (Million Tons)	1,110	1,295	1,279	1,265	1,340	1,325	1,329
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.18	14.81	12.87	13.02	13.00
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.07	1.04	0.98	0.98	0.96
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	6	125	15	19	139

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NOX08.D060801A, and M2SO208P.D061201A.

well. In 2000, there were approximately 212 coal preparation plants in the United States.[30] About two-thirds of the bituminous coal mined in the East for electric power plants is cleaned, whereas the subbituminous coal and lignite shipped from western mines to coal-fired generating plants is generally only crushed and screened to facilitate handling and to remove extraneous material introduced during mining.[31] One estimate of the reductions in Hg provided by coal cleaning indicates a range of 0 to 64 percent removal, with an average of 21 percent, depending on the cleaning process, Hg concentration in the raw coal, and the technique used to measure Hg concentration.[32] The coal characteristics data that are used for this report are based on receipts at generators and therefore reflect the effects of quality improvements resulting from coal preparation.

RPS Cases

In the RPS cases, all the nonhydroelectric renewable generation technologies are projected to increase their market share of total generation, and the electricity generation shares of both coal and natural gas are projected to be lower than in the reference case. The effective price premium associated with using renewable fuels declines over time relative to nonrenewable sources, because the cost of the RPS credits that nonrenewable electricity generators must hold increases as the renewable share target becomes more stringent. In the RPS 10% case, the projected impacts on coal markets fall roughly midway between the results in the reference and RPS 20% cases.

In the reference case, coal consumption by electricity generators is expected to increase steadily from 2000, reaching 1,196 million tons in 2020. In the RPS 20% case, coal consumption by electricity generators increases at a slower rate over the period—to 1,043 million tons—13 percent lower than the reference case, as the share of total generation provided by renewable energy increases linearly on a year-by-year basis over the period and displaces fossil fuel demand (Table 15). Higher electricity prices, which decrease total electricity sales, also contribute to the reduced coal demand. Coal production in the RPS 20% case is projected to increase from 1,110 million tons in 1999 to 1,188 million tons in 2020, compared with 1,340 million tons in 2020 in the reference case. A larger share of the coal production decline relative to the reference case is projected to occur in the western States for three reasons: (1) wider availability and greater penetration of renewable energy (particularly wind and geothermal) in electricity generation markets in the West; (2) continued demand for industrial, metallurgical, and export coal—markets that are not affected by the RPS and are expected to continue to draw heavily on eastern coal; and (3) lower SO_2 allowance prices resulting from the reduction in coal demand permitting greater use of higher sulfur coal from mines east of the Mississippi River.

Existing coal-fired units are assumed to be able to co-fire biomass along with coal up to a maximum of 5 percent of the energy input to the boilers, if the delivered cost of biomass to the plant is competitive with coal and no

Table 14. Coal Market Projections in Mercury Emission Reduction Cases, 2010 and 2020

Projection	1999	2010				2020			
		Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case	Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,091	1,051	1,132	1,196	1,144	1,080	1,176
Total Coal Production (Million Tons)	1,110	1,295	1,238	1,201	1,282	1,340	1,289	1,229	1,320
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	15.37	14.83	14.25	12.87	14.10	14.52	13.32
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.06	1.09	1.04	0.98	0.98	1.01	0.97
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	43	18	27	15	43	52	27
Average Hg Content of Coal (Pounds per Trillion Btu)[b]	7.7	7.2	6.7	6.1	7.1	7.0	6.5	6.3	7.0

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[b]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M6008.D060801A, M2M9008.D060801A, and M2M9008M.D060801A.

[30]*Coal Age* (October 2000).

[31]Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(93) (Washington, DC, February 1995), p. 25.

[32]U.S. Environmental Protection Agency, *Mercury Study Report to Congress, Volume 2: An Inventory of Anthropogenic Mercury Emissions in the United States* (Washington, DC, December 1997).

extensive modifications to the plant are required. Generation based on biomass co-firing with coal is projected to increase from 0.9 billion kilowatthours in 1999 to 79 billion kilowatthours in 2020 in the RPS 20% case, compared with 6 billion kilowatthours in 2020 in the reference case.

CO_2 1990-7% 2008 Case

In the CO_2 1990-7% 2008 case, substantial reductions in coal consumption are projected, with corresponding drops in coal production (Table 16). To continue using coal under the CO_2 cap, a power plant operator would have to pay for both the coal and the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2008 case, the delivered price of coal to electricity generators in 2020 is projected to average $0.84 per million Btu, but the costs of CO_2 allowances are projected to add a penalty of $3.87 per million Btu. Thus, the effective cost of using coal is projected to be $4.71 per million Btu in 2020. The corresponding effective cost to electricity generators in the reference case is projected to be $0.98 per million Btu in 2020.

In the CO_2 cap case, the use of coal is projected to decline sharply at many electric power plants. Although the effective price for coal on a Btu basis is still projected to be below that for natural gas (which incurs a lower requirement for carbon allowances), the price differential between the two fuels is expected to narrow slightly, and the higher efficiency of natural gas generation is expected to tip the generation share away from coal in many regional markets.

Because CO_2 allowance requirements are projected to increase operating costs for generators, many existing coal-fired power plants are projected to become uneconomical in the CO_2 1990-7% 2008 case, causing large blocks of capacity to be retired and replaced by natural

Table 15. Coal Market Projections in Two RPS Cases, 2010 and 2020

		2010			2020		
Projection	1999	Reference Case	RPS 10% Case	RPS 20% Case	Reference Case	RPS 10% Case	RPS 20% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,122	1,074	1,196	1,131	1,043
Total Coal Production (Million Tons)	1,110	1,295	1,273	1,225	1,340	1,275	1,188
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.05	14.19	12.87	12.99	13.28
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.06	1.07	0.98	0.98	0.97
Electricity Generation with Biomass Co-firing (Billion Kilowatthours)	0.9	10	49	40	6	92	79
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	6	6	15	10	10

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20H_X.D070601A, and M2RPS20_X.D070601A.

Table 16. Coal Market Projections in the CO_2 1990-7% 2008 Case, 2010 and 2020

		2010		2020	
Projection	1999	Reference Case	CO_2 1990-7% 2008 Case	Reference Case	CO_2 1990-7% 2008 Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	559	1,196	491
Total Coal Production (Million Tons)	1,110	1,295	715	1,340	641
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.22	12.87	12.77
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.93	0.98	0.84
Effective Delivered Coal Price to Generators[a] (1999 Dollars per Million Btu)	1.22	1.06	4.93	0.98	4.71
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	0	15	0

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

gas capacity. The combined effects of lower in-service coal capacity and lower utilization of the remaining coal capacity are projected to reduce coal consumption for electricity generation to levels that are approximately 41 percent of those in the reference case projections. With large reductions in coal-fired generation projected as a result of the CO_2 allowance requirements, SO_2 emissions are projected to be well below the CAAA90 caps, eliminating the need for additional scrubber retrofits. Total coal production is projected to decline at a slower rate than demand from the electricity generation sector, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to CO_2 allowance fees) remains essentially unchanged from reference case values.

Integrated Cases With No RPS

In the integrated cases with CO_2 caps, coal consumption is projected to be reduced sharply. When the costs associated with acquiring CO_2 allowances are added to the delivered price of coal (and no RPS requirement exists), the effective delivered price is quadrupled relative to that in the reference case by 2010. As in the CO_2 1990-7% 2008 case, coal-fired electricity generation loses substantial market share to natural-gas-fired generation, as compared with its share of total electricity generation in the reference case. In addition, total electricity sales decline, reducing overall generation requirements.

The integrated cases that assume a cap on power sector CO_2 emissions at 7 percent below the 1990 level have the most severe impacts on coal markets and are projected to reduce coal consumption by electricity generators by an additional 49 to 81 million tons relative to the integrated cases that cap CO_2 emissions at the 1990 level (Table 17). In all the cases with CO_2 caps, the combined effects of lower installed coal-fired generation capacity and lower utilization of the remaining coal-fired capacity are projected to reduce coal consumption for electricity generation in 2020 to levels that range from 40 to 46 percent of those projected in the reference case. In the integrated cases that add an Hg emission cap, additional reductions in coal consumption are projected. Total coal production is projected to decline at a slower rate than demand for coal in the electricity generation sector, however, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to the CO_2 caps) remains essentially unchanged from reference case values. With large reductions in coal-fired generation projected as a result of the cost impacts of CO_2 allowances and the cost of meeting the Hg cap, SO_2 emissions are projected to fall well below the tightened SO_2 cap.

Integrated Cases With an RPS

When an RPS is included in the set of integrated scenario requirements, both coal-fired electricity generation and

Table 17. Coal Market Projections in Selected Integrated Cases With No RPS, 2010 and 2020

Projection	1999	2010					2020			
			Integrated Cases				Integrated Cases			
		Reference Case	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	NO_x, SO_2, CO_2 1990-7%, Hg	Reference Case	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	NO_x, SO_2, CO_2 1990-7%, Hg
Electricity Sector Coal Consumption (Million Tons)	923	1,145	694	567	518	1,196	554	485	478
Total Coal Production (Million Tons)	1,110	1,295	853	724	674	1,340	721	641	640
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	13.42	13.43	14.38	12.87	11.90	12.16	13.41
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.95	0.91	0.93	0.98	0.85	0.82	0.85
Effective Delivered Coal Price to Generators[a] (1999 Dollars per Million Btu)	1.22	1.06	3.83	4.54	3.99	0.98	4.52	4.77	4.68
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	14	19	21	15	14	19	21
Average Hg Content of Coal (Pounds per Trillion Btu)[c]	7.7	7.2	6.8	7.2	6.4	7.0	6.8	7.1	6.4

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[c]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A, and M2P7B08.D060801A.

coal production are higher than projected in the integrated cases with no RPS, and the effective delivered price of coal to electricity generators is lower (Table 18). With an RPS, the resulting increase in electricity generation from renewable fuels, which produce no net CO_2 emissions, lessens the need to reduce coal-fired generation to comply with the CO_2 cap.

In the integrated moderate targets case, in which all emission caps and the RPS are assumed to be less stringent than those in the integrated all CO_2 1990-7% case, electricity sector coal consumption in 2020 is 106 million tons higher than projected in the integrated all case. The effective delivered price of coal to electricity generators is higher in the integrated moderate targets case than in the integrated all case, because the CO_2 reductions projected to result from the use of renewable fuels are reduced to only one-half those in the integrated case with more stringent caps and RPS requirements, resulting in a higher cost impact from acquiring CO_2 emission allowances.

Regional Impacts on Coal

In all the cases examined in this analysis, coal production is projected to be lower than projected in the reference case, because the cost impacts of the various emission caps make the delivered price of coal higher relative to other fuels and reduce demand for electricity. There are also impacts on regional shares of coal production. Caps on Hg emissions lead to a shift away from coal types with high Hg content (such as Gulf lignite) and their replacement by coal with lower Hg content (from regions such as the Rocky Mountains). Scrubber retrofits that are required to meet an SO_2 cap are expected to lower production from regions producing low-sulfur coal. Table 6 in Chapter 2 lists coal quality data (heat content, sulfur content, and Hg content) for coals from the major supply regions.

The ability of the coal industry to adapt quickly to the requirements imposed by emission caps is subject to several infrastructure issues. The early closing of existing mines (such as those producing high-Hg coals) could result in substantial financial penalties, such as severance pay, unrecovered equipment costs, and reclamation charges, that could hamper the ability of some companies to secure funding for new mines. In the transportation sector, it would be necessary to establish new transportation patterns, which could create bottlenecks and raise costs. Increased use of low-sulfur and low-Hg coals could create near-term issues of licensing, siting, and staffing new mines that might otherwise not be needed.

Natural Gas Markets

Reference Case

The reference case is based on *AEO2001* but incorporates more recent data on natural gas markets. Wellhead prices for natural gas are expected to fall from recent highs to $3.22 (constant 1999 dollars) per thousand cubic feet by 2020. Natural gas consumption in the reference case is expected to grow more quickly over the next two decades than total energy use. By 2020, the share of energy provided by natural gas is expected to increase to

Table 18. Coal Market Projections in the Integrated Moderate Targets and Integrated All CO_2 1990-7% Cases, 2010 and 2020

Projection	1999	2010 Reference Case	2010 Integrated Moderate Targets Case	2010 Integrated All CO_2 1990-7% Case	2020 Reference Case	2020 Integrated Moderate Targets Case	2020 Integrated All CO_2 1990-7% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	738	587	1,196	680	574
Total Coal Production (Million Tons)	1,110	1,295	895	749	1,340	836	731
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.14	15.43	12.87	12.68	14.08
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.98	0.98	0.98	0.88	0.91
Effective Delivered Coal Price to Generators (1999 Dollars per Million Btu)[a]	1.22	1.06	3.83	4.15	0.98	3.94	3.19
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	4	28	15	4	32
Average Hg Content of Coal (Pounds per Trillion Btu)[a]	7.7	7.2	6.6	6.4	7.0	6.6	6.4

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[c]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, and M2P7B08R_X.D070601A.

28 percent from 23 percent in 1999, and the total volume of natural gas used is expected to grow to 35.2 trillion cubic feet from 21.7 trillion cubic feet in 1999. Natural gas use for electricity generation is projected to grow by 5.2 percent per year, faster than in the other demand sectors, reaching 11.2 trillion cubic feet per year by 2020. The projected growth in electricity generation consumption of natural gas accounts for 7.3 trillion cubic feet out of the 13.5 trillion cubic feet projected increase in total consumption between 1999 and 2020. The rate of growth of natural gas use in other sectors of the economy is more modest.

Domestic production is expected to grow to meet increased demand. Production of natural gas in 2020 is projected to be 10.8 trillion cubic feet per year higher than it was in 1999. Natural gas produced offshore is expected to account for 26 percent of total domestic production, with unconventional gas accounting for an additional 30 percent. Imports are also expected to grow. By 2020, net natural gas imports from Canada are projected to be 5.4 trillion cubic feet per year, 2.1 trillion cubic feet higher than they were in 1999. Additional net imports of liquefied natural gas (LNG) are expected to grow from 97 billion cubic feet in 1999 to 792 billion cubic feet in 2020, adding 695 billion cubic feet to total U.S. supplies. The additional projected LNG imports are assumed to enter the U.S. market through existing facilities that expand their capacity (see box below).

Low oil prices in 1998 cut revenues to the combined oil and natural gas industry and reduced exploration for natural gas. This, coupled with higher demand driven by strong economic growth during the first three quarters of 2000 and unusually cold weather in the last quarter of 2000, led to higher prices in 2000 than were seen throughout the 1990s. During 2000, the average annual wellhead price was $3.52 per thousand cubic feet (1999 dollars). The average wellhead price is expected to be even higher in 2001, but prices are projected to decline from these high levels as markets move back into equilibrium. In the reference case, the projected price of natural gas is $2.96 per thousand cubic feet in 2005 and $2.87 per thousand cubic feet in 2010. In the later years of the projections, continued strong demand for natural gas and increasingly costly new reserves (see box on page 50) lead to higher prices. By 2020, the projected wellhead price of natural gas reaches $3.22 per thousand cubic feet in the reference case.

Hg Emission Reduction Cases

Reducing Hg emissions is expected to lead to faster growth in natural gas use as some electric power generators switch from coal to natural gas in order to lower their Hg emissions. This leads to greater consumption by electricity generators, over and above the strong growth in consumption of natural gas that is already expected in the reference case. Stronger demand leads to higher natural gas prices than those projected in the reference case. Domestic production and imports are also higher. A higher Hg emissions cap of 20 tons has much less effect on U.S. natural gas prices and production. The projected effects on natural gas prices are also estimated to be lower if MACT standards are used rather than a cap and trade system, because without tradable allowances there is less incentive to switch to natural gas.

By 2010, electricity generation use is projected to be 7.6 trillion cubic feet in the Hg 5-ton case, compared with 6.8 trillion cubic feet in the reference case (Table 19). By 2020, the volume of natural gas used by electricity generators increases to 11.9 trillion cubic feet in the Hg 5-ton case, about 0.7 trillion cubic feet higher than projected in the reference case. In the Hg 20-ton case, raising the Hg cap reduces the incremental natural gas use for

Potential New Sources of Natural Gas Supply

The projected growth in U.S. natural gas supplies in the reference case is accomplished by expanding domestic production and current sources of imports. However, there are other new potential sources of supply that could make more natural gas available to U.S. consumers and therefore lower prices. They are available in cases where natural gas demand and thus natural gas prices are high enough to support these new potential sources.

One example is natural gas from Alaska, brought to consumers either as liquefied natural gas (LNG) or through a proposed pipeline connecting the Alaskan North Slope to Alberta, Canada, and then to the lower 48 States. A pipeline was discussed in the early 1980s but never built. As of this writing, ExxonMobil Production, BP Exploration Alaska, and Phillips Alaska are working jointly to assess the viability of a pipeline for Alaskan gas, with a potential capacity of up to 4 billion cubic feet per day, or 1.4 trillion cubic feet per year. Implementing a pipeline is estimated to take 5 to 7 years.

A second possibility is expanding U.S. LNG import capacity. In the reference case for this analysis, growth in LNG imports occurs through expansion of existing facilities. Other possible sites for new LNG facilities that are currently being explored include Florida; Baja California, Mexico; the Bahamas with a pipeline connection to Florida; offshore in the Gulf of Mexico; the U.S. West Coast; and the DelMarva Peninsula and North Carolina on the U.S. East Coast. As of this point, none of these proposed projects has moved beyond the planning stage.

electricity generation, although it is still above the projected levels in the reference case. Industrial, commercial, and residential use of natural gas is roughly the same as in the reference case.

The increased demand for natural gas resulting from Hg emissions reductions leads to higher prices (Figure 23). By 2010, the projected wellhead price in the Hg 5-ton case reaches $3.06 per thousand cubic feet, compared with $2.87 in the reference case. The projected price difference fluctuates but is still $0.19 per thousand cubic feet in 2020, when the wellhead price is projected to be $3.22 in the reference case and $3.41 in the Hg 5-ton case. While the Hg emissions requirements in the Hg 5-ton case cause more natural-gas-fired capacity to be adopted earlier, much of the additional capacity is ultimately brought on line toward the end of the forecast period in the reference case.

When the Hg requirements are implemented, projected domestic natural gas production in the Hg 5-ton case is higher than in the reference case (Figure 24). In 2010, domestic production in the Hg 5-ton case is projected to be 24.1 trillion cubic feet, compared with 23.4 trillion cubic feet in the reference case. The difference in the volume of production is split roughly equally among offshore production, onshore conventional production, and unconventional production. By 2020, the difference

Table 19. Natural Gas Market Projections in Three Mercury Emission Reduction Cases, 2010 and 2020

Projection	1999	2010				2020			
		Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case	Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	2.90	3.06	2.89	3.22	3.33	3.41	3.24
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	23.76	24.09	23.57	29.47	29.58	30.12	29.54
Net Imports (Trillion Cubic Feet)	3.42	5.00	5.05	5.12	5.02	5.82	5.85	5.92	5.84
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	7.13	7.59	6.98	11.19	11.33	11.92	11.29

Source: National Energy Modeling System, runs M2BASE.D060801A, M2M6008.D060801A, M2M9008.D060801A, and M2M9008M.D060801A.

Depletion of Natural Gas Resources

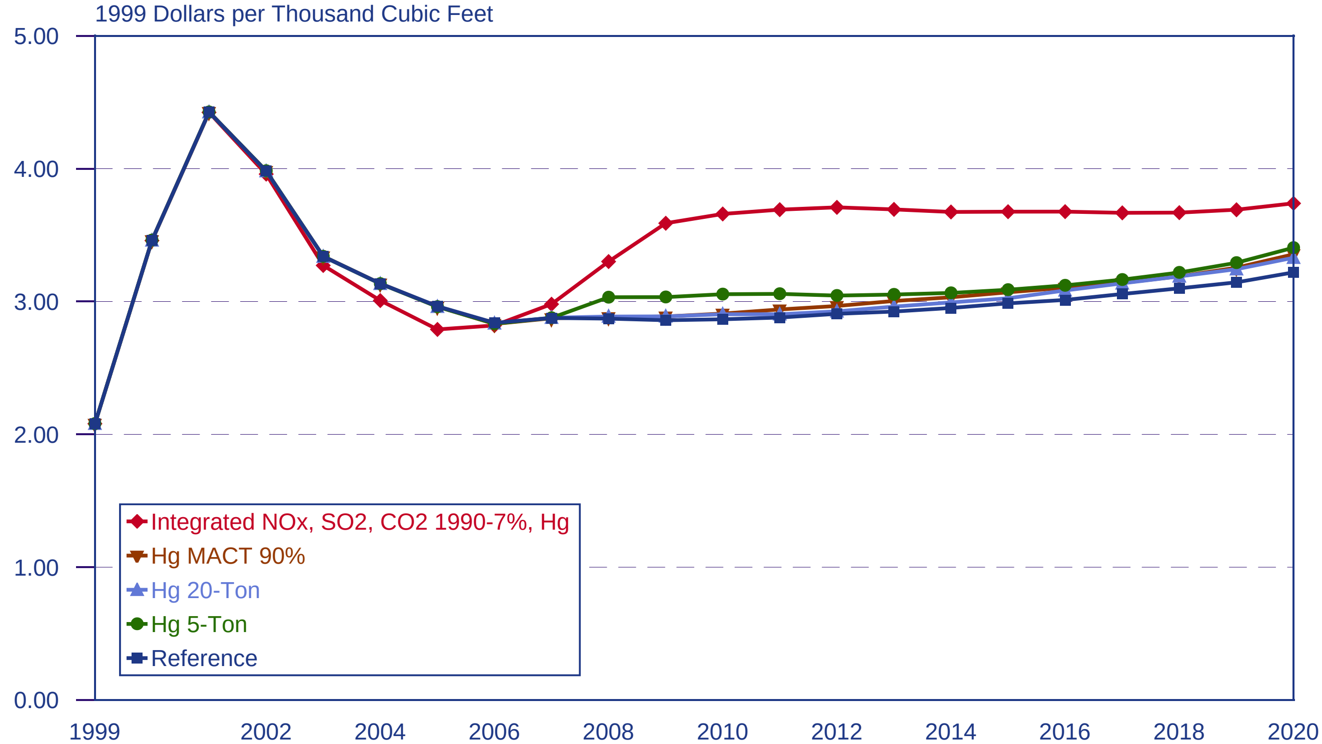
Natural gas is a finite resource. As discovered natural gas reserves are developed and produced, additional reserves must be discovered in order to maintain production levels. Over time, replacing depleted reserves is increasingly difficult. The largest and most easily developed resources tend to be developed first, and subsequent reserve additions are, on average, smaller and more expensive to develop. The increased difficulty of adding new reserves due to the cumulative effects of depletion are offset by improvements in technology, which lowers exploration costs, the number of dry holes, and drilling and production costs.

The cases developed for this study use the Oil and Gas Supply Model (OGSM) of the National Energy Modeling System to project future natural gas production. The OGSM specifically incorporates the effects of cumulative depletion on projected future natural gas discoveries, based on historical patterns. Some industry observers have suggested, however, that current natural gas discoveries per successful well are considerably lower than they have been in the past. They are concerned that the effects of cumulative depletion are more severe than indicated by historical trends. Stronger than expected depletion effects could make future natural gas production more difficult and lead to higher prices than are projected in this study.

Additional discussion of the possible adverse effects of cumulative depletion can be found in a recent EIA Service Report, *Accelerated Depletion: Assessing Its Impacts on Domestic Oil and Natural Gas Prices and Production* (Sept. 2000, DOE/FE-0424). In that study, future reserve additions were assumed to be only two-thirds of the size suggested by long-term historical trends. The expected production schedule of new wells was also assumed to have a higher percentage of each well's total output coming in the first years of production. Under the accelerated depletion assumptions, the projected wellhead price of natural gas in 2020 was 48 percent higher than projected in the study's reference case used (which differed from the reference case for the current analysis). Assumptions of faster technological progress and increased access to reserves mitigated the higher price projections.

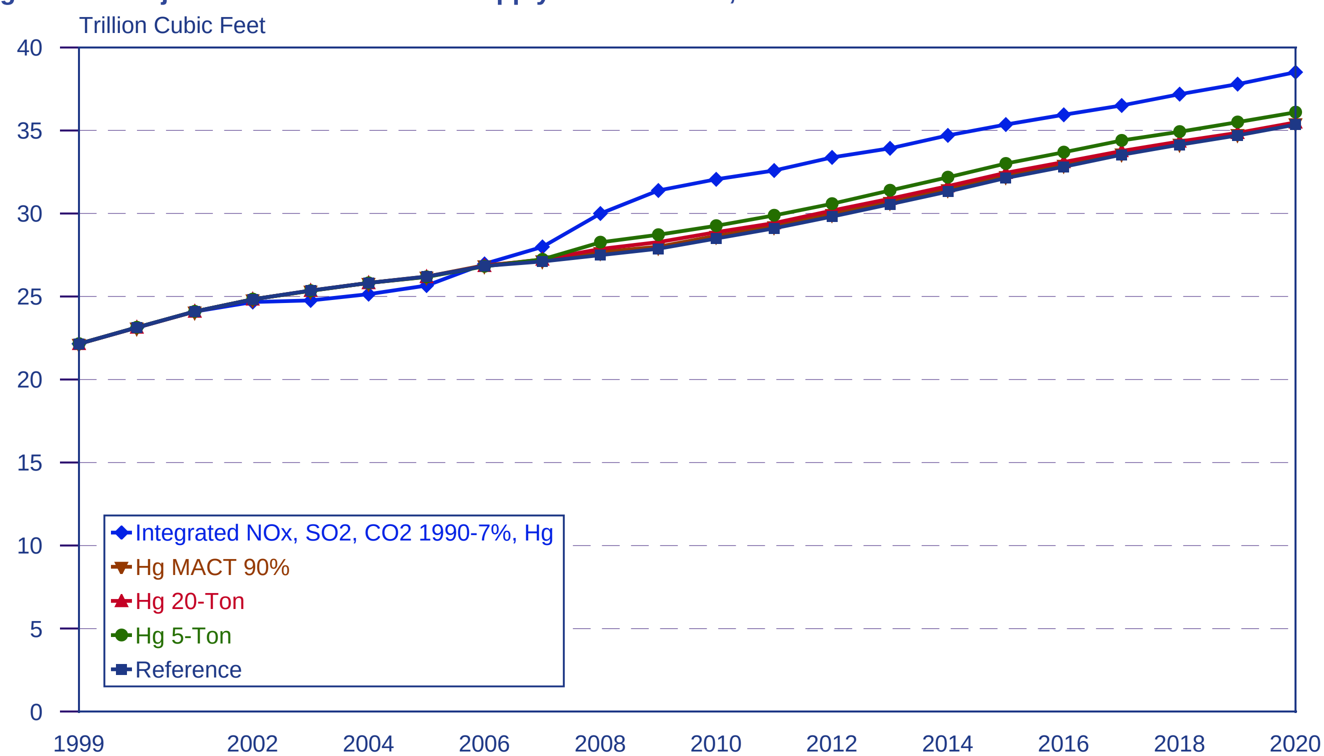
The assumptions used in the *Accelerated Depletion* study were designed to explore the potential adverse effects of greater than expected reductions in domestic natural gas supply. The assumptions for the cases in this analysis are based on the historical trend, which indicates much less dramatic effects of depletion on potential supply.

Figure 23. Projected U.S. Natural Gas Wellhead Prices in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A.

Figure 24. Projected U.S. Natural Gas Supply in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A.

in projected production between the Hg 5-ton case and the reference case is 650 billion cubic feet, or roughly the same as expected in 2010. Approximately two-thirds of the difference in production is provided by higher unconventional production. The stronger reliance on unconventional production in the Hg 5-ton case is one of the reasons why prices remain higher than in the reference case.

Increased net imports account for only a small part of the difference in supply between the reference case and the Hg 5-ton case. By 2020, Canadian net imports are projected to be 5.5 trillion cubic feet per year in the Hg 5-ton case compared with 5.4 trillion cubic feet in the reference case. Projected net imports from other sources, including LNG imports and pipeline imports from Mexico, are the same in the two cases.

Higher wellhead prices for natural gas result in not only higher electricity prices, but also higher direct costs to residential natural gas consumers. In the Hg 5-ton case, the average price paid by residential customers in 2020 is estimated to be $7.01 per thousand cubic feet, 2.6 percent higher than the reference case price of $6.83 per thousand cubic feet. The average household residential cost of natural gas in 2020 is 2 percent higher in the Hg 5-ton case than in the reference case.

Under a cap and trade system, such as that assumed in the Hg 5-ton case, producers who reduce their emissions below their allowances can sell credits to other electricity generators. In the Hg MACT 90% case, each facility is assumed to meet its target without a credit trading option. Because mitigation costs are proportional to a percentage rather than an absolute reduction, the incentives for the electricity generation sector to meet its emission reduction requirements by switching fuels is greatly reduced. Consequently, the projected increase in demand for natural gas for electricity generation is lower than in the cap and trade cases. The Hg MACT 90% case shows lower demand from electricity generators (11.29 trillion cubic feet in 2020), leading to lower prices than are projected in the comparable cap and trade cases. The natural gas wellhead price projected for 2020 in the Hg MACT 90% case is $3.24 per thousand cubic feet, 5 percent lower than the 2020 price in the Hg 5-ton case and only $0.02 feet higher than in the reference case.

RPS Cases

The inclusion of a renewable portfolio standard reduces the projected rate of growth in natural gas consumption by U.S. power generators. Under an RPS, total demand for natural gas is expected to be lower than in the reference case. Projected prices and production are also lower.

The introduction of an RPS leads to changes in natural gas markets by slowing the projected rate of increase in electricity generation demand (Table 20). In the RPS 20% case, the differences in projected prices, consumption, and production steadily increase through 2020, as the required share generated by nonhydroelectric renewable resources grows to 20 percent in 2020. The volume of natural gas used by electricity generators in 2020 is projected to be 7.0 trillion cubic feet, compared with 11.2 trillion cubic feet in the reference case.

The sharply lower projected demand from electricity generators results in lower natural gas prices. By 2010, the wellhead price of natural gas is projected to be $2.65 per thousand cubic feet, 7.7 percent lower than projected in the reference case. The projected price of natural gas in the RPS 20% case is $2.66 per thousand cubic feet in 2020, $0.56 (17 percent) lower than in the reference case.

Lower prices for natural gas lead to slightly higher projected consumption in the industrial, commercial, and residential sectors, but not enough to offset the projected difference in electricity generator use. In 2020, consumption from these sectors together is 21.6 trillion cubic feet, compared with 20.9 trillion cubic feet in the reference case. Total natural gas consumption in the RPS case is projected to be 31.4 trillion cubic feet in 2020, compared with 35.2 trillion cubic feet in the reference case.

Lower projected consumption and prices in the RPS 20% case lead to lower projected domestic production and net imports. By 2020, projected U.S. production is 26.1 trillion cubic feet in the RPS 20% case, compared with

Table 20. Natural Gas Market Projections in Two RPS Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference Case	RPS 10% Case	RPS 20% Case	Reference Case	RPS 10% Case	RPS 20% Case
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	2.81	2.65	3.22	2.95	2.66
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	23.21	22.45	29.47	28.22	26.09
Net Imports (Trillion Cubic Feet)	3.42	5.00	5.02	4.86	5.82	5.67	5.38
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	6.59	5.59	11.19	9.65	7.00

Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20H_X.D070601A, and M2RPS20_X.D070601A.

29.5 trillion cubic feet in the reference case. Net imports are also lower. Canadian net imports in 2020 are estimated to be 5.0 trillion cubic feet, compared with 5.4 trillion cubic feet in the reference case.

Lower prices lead to lower expenditures by consumers. By 2020, the average household expenditure on natural gas is 5 percent lower in the RPS 20% case than projected in the reference case. The industrial price for natural gas drops to $3.39 per thousand cubic feet, about 14 percent lower than projected in the reference case.

In the RPS 10% case, reducing the required amount of generation from nonhydroelectric renewable energy sources raises the projected consumption of natural gas as compared with a more stringent RPS, but consumption still remains below the reference case level. By 2010, natural gas use for electricity generation in the RPS 10% case is 220 billion cubic feet lower than in the reference case, leading to projected wellhead prices that are $0.06 per thousand cubic feet lower than in the reference case. The difference in electricity generator use increases to 1.54 trillion cubic feet by 2020, resulting in a projected wellhead price $0.27 lower than in the reference case but still $0.29 higher than in the RPS 20% case. Although the RPS 10% case leads to lower natural gas prices than are projected in the reference case, the differences are small through 2010 and considerably smaller than the differences between the reference case and the RPS 20% case.

Integrated Emission Reduction Cases

Integrated NO_x, SO_2, CO_2 1990-7%, Hg Case

An integrated emission control strategy that includes CO_2 emission reductions greatly increases the demand for natural gas by electricity generators. While end-of-pipe emission controls can reduce many types of emissions, reducing CO_2 emissions to the required level—7 percent below 1990 emissions—requires much more intensive fuel switching from coal to natural gas, which has lower CO_2 emissions per Btu.

The sustained higher demand for natural gas that is caused by CO_2 emissions reductions are assumed to lead to new sources of natural gas supply that are not expected to become available in the cases that do not include CO_2 emission caps. First, due to the sustained higher prices in the United States, Mexico is assumed to become a net exporter to the United States instead of a net importer. By 2020, net imports from Mexico are assumed to be 360 billion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, rather than the net exports to Mexico of 400 billion cubic feet assumed in the reference case. Second, strong sustained demand and higher prices are assumed to lead to an additional 1 trillion cubic feet from other sources of supply, including LNG imports and Alaskan production through Canada. The additional supply becomes available starting in 2008, as the restrictions on CO_2 emissions are implemented and wellhead prices rise. The net effect of these assumptions is that imports are projected to be 2.3 trillion cubic feet higher in 2020 than projected in the reference case (Table 21).

By 2010, the projected volume of natural gas used to generate electricity is 10.6 trillion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, 3.8 trillion cubic feet higher than the projected level in the reference case. By 2020, total electricity generation use is projected to grow to 13.4 trillion cubic feet, compared to 11.2 trillion cubic feet in the reference case. Although higher prices lead to slightly lower consumption in other sectors of the economy, total natural gas consumption in all sectors in 2020 is projected to be 38.3 trillion cubic feet, 3.1 trillion cubic feet higher than in the reference case.

In the early years of the forecast, demand from electricity generators is slightly lower as new, more efficient natural-gas-fired capacity is brought on line in anticipation of the 2008 emissions targets. By 2010, however, the wellhead price of natural gas reaches $3.66 per thousand cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, $0.79 higher per thousand cubic feet than in the reference case. In 2020, the projected price of natural gas is $3.74 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with $3.22 in the reference case. Higher prices are passed through to consumers, and in 2020 the average household expenditure in the integrated case is

Table 21. Natural Gas Market Projections in Two Integrated Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference Case	Integrated Cases: NO_x, SO_2, CO_2 1990-7%	Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	Reference Case	Integrated Cases: NO_x, SO_2, CO_2 1990-7%	Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	3.50	3.66	3.22	3.80	3.74
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	24.90	25.31	29.47	30.44	30.29
Net Imports (Trillion Cubic Feet)	3.42	5.00	6.60	6.69	5.82	7.97	8.16
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	9.93	10.63	11.19	13.12	13.43

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, and M2P7B08.D060801A.

projected to be 6 percent higher than in the reference case.

U.S. production of dry gas reaches 30.3 trillion cubic feet in 2020 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with 29.5 trillion cubic feet in the reference case. Unconventional natural gas production in 2020 is projected to be 900 billion cubic feet, or 10 percent, higher in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case than in the reference case, and cumulative total gas production in 2020 is nearly 16 trillion cubic feet higher. These factors underlie the persistent higher prices in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, despite more imports than assumed in the reference case. About 74 percent of the additional projected supply in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case is met through increased imports, the least-cost source of supply. Increased Canadian imports are 300 billion cubic feet higher in 2020 than projected in the reference case.

Integrated NO_x, SO_2, CO_2 1990-7% Case

Although this case does not include Hg emissions, the effects on the natural gas markets are similar to the effects of the integrated NO_x, SO_2, CO_2 1990-7%, Hg case but less pronounced (Table 21). Natural gas use for electricity generation is lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, because the absence of Hg emissions reductions causes less projected fuel switching to natural gas. By 2010, projected natural gas use in the electric power sector is 0.7 trillion cubic feet lower than in the corresponding case with Hg reductions. At $3.50 per thousand cubic feet, the projected wellhead price in 2010 is $0.16 lower than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. The difference between the two cases in projected natural gas use for electricity generation falls to 0.3 trillion cubic feet by 2020.

Integrated All CO_2 1990-7% Case

Imposing an RPS in conjunction with an integrated emission control program has a dramatic effect on projected natural gas demand and prices. In this case, projections of future supply do not include the higher levels of imports assumed in most of the other cases that include CO_2 emissions reduction, because prices are not projected to be high enough to make those additional supplies feasible. In the integrated all CO_2 1990-7% case, consumption grows more slowly than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, reaching 34.1 trillion cubic feet by 2020, compared with 38.3 trillion cubic feet in the corresponding case without the RPS. As a result, the wellhead price of natural gas in 2020 is $0.43 per thousand cubic feet lower, and the average residential bill is 4 percent lower than in the same case without an RPS (Table 22).

The projected level of drilling and the total cumulative production (measured from 2000) diverge strongly between the integrated all CO_2 1990-7% case and the corresponding case without the RPS (Table 23). In 2010, both total number of wells drilled and cumulative production are fairly similar between cases. By 2020, however, the higher production required to meet growing demand by electricity generators increases cumulative production to 519.8 trillion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with 506.6 trillion cubic feet in the corresponding RPS case. The difference in cumulative natural gas production between the two cases is equivalent to about 9 months total production at current levels. The total number of wells required to meet projected production is 46.3 thousand in 2020 in the integrated NO_x, SO_2, CO_2 1990-7% and Hg, 35 percent higher than it is in the corresponding case with an RPS. Including the RPS reduces the quantity of reserves that must be replaced and the amount of drilling required to meet production, dramatically lowering the projected wellhead price.

Integrated High Gas Price Case

The integrated high gas price case considers the effects of less optimistic assumptions about natural gas supply in an integrated case that includes a cap on power sector CO_2 emissions but no RPS. This case is intended to show how natural gas and electricity markets might react if the additional supplies that are projected in the other

Table 22. Natural Gas Market Projections in Three Integrated Cases, 2010 and 2020

Projection	1999	2010 Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	2010 Integrated Cases: High Gas Price	2010 Integrated Cases: All CO_2 1990-7%	2020 Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	2020 Integrated Cases: High Gas Price	2020 Integrated Cases: All CO_2 1990-7%
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	3.66	4.08	3.13	3.74	5.05	3.31
Total Domestic Production (Trillion Cubic Feet)	18.62	25.31	25.89	24.84	30.29	26.93	28.40
Net Imports (Trillion Cubic Feet)	3.42	6.69	5.57	5.33	8.16	6.40	5.85
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	10.63	10.25	8.35	13.43	10.04	8.97

Source: National Energy Modeling System, runs M2P7B08.D060801A, M2P7B08L.D060901A, and M2P7B08R_X.D070601A.

cases that limit CO_2 emissions prove to be unavailable, despite higher prices due to slower technological progress. First, the additional sources of supply—including Alaskan production and imports from Mexico or as LNG—that are included in other cases that limit CO_2 emissions (but are not projected in the reference case) are not allowed in the integrated high gas price case. Although the higher prices associated with this case would normally be expected to make these additional supplies available, there is more uncertainty concerning them than there is for the domestic production and imports projected in the reference case. Second, the projected rate of technological improvement in natural gas production is also reduced by 25 percent, making the cost of drilling in the long term higher and reducing the success rate and the volume of reserves added per well.[33]

Slower technology growth reduces the number of productive wells that can be drilled domestically, even as prices are higher. By 2020, successful well completions projected in the integrated high gas price case are approximately 42,000, compared with more than 46,000 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Domestic production is 3.4 trillion cubic feet, or 11 percent, lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Coupled with the changes in the assumed level of available imports, the resulting supplies are more than 5 trillion cubic feet lower than the supplies in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

Limiting potential supply pushes expected prices even higher than they are in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. By 2020, the average wellhead price of natural gas in the high gas price case reaches $5.05 per thousand cubic feet (Table 22). The higher price of natural gas in the integrated high gas price case causes residential expenditures for natural gas to be 10 percent higher than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. High prices also cause commercial, residential, and industrial customers, as well as electricity generators, to limit their use of natural gas. By 2020, total projected natural gas consumption in the integrated high gas price case is 33.2 trillion cubic feet, 13 percent lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

The sharp differences in projected prices and total consumption illustrate the sensitivity of natural gas market projections to assumptions about available supply. However, this is an extreme case. The increases in demand for natural gas that accompany CO_2 emission reductions are generally expected to sustain the prices that make additional supply feasible, including LNG imports. In addition, the lower rate of technological improvement assumed in this case does not reflect historical trends. The rate of technology improvement in costs and finding rates that are used in the other cases in this report are projected econometrically from historical production trends, and they are considered to be more likely estimates of future trends.

The high levels of demand for natural gas in the electric power sector that are projected in the CO_2 cap cases for this analysis would constitute a serious challenge for the U.S. natural gas market, during a period when the industry already is expecting strong demand growth. U.S. natural gas production is projected to grow at near record rates between 2005 and 2010 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case and in the integrated high gas price case. Several consecutive years of growth at the projected rates could prove to be difficult to achieve, due to limitations on available trained workers, drilling rigs, and other production capital. The pipeline infrastructure would also have to be expanded at record rates.[34]

Table 23. Projections for Natural Gas Wells Drilled and Cumulative Production in Two Integrated Cases, 2010 and 2020

Projection	Reference Case	Integrated NO_x, $S0_2$, CO_2 1990-7%, Hg Case	Integrated All CO_2 1990-7% Case
2010			
Thousand Natural Gas Wells Drilled	29.9	34.4	30.8
Cumulative Natural Gas Production, 2000-2010 (Trillion Cubic Feet)	236.1	240.7	238.4
2020			
Thousand Natural Gas Wells Drilled	39.4	46.3	34.3
Cumulative Natural Gas Production, 2000-2020 (Trillion Cubic Feet)	504.1	519.8	506.6

Source: National Energy Modeling System, runs M2BASE.D060801A, M2P7B08.D060801A and M2P7B08R_X.D070601A.

[33]The changes in the projected rate of technological advancement made in the integrated high gas price case are the same changes that were made in the slow technology case in the *AEO2001*.

[34]For a discussion of the challenges faced in meeting the production required in a CO_2 emission reduction case, see the earlier EIA report, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF-2000-05 (Washington, DC, December 2000).

Renewable Fuels Markets

EIA's earlier report on multiple emission reductions included projections of renewable energy use for electricity generation in cases with caps on emissions of SO_2, NO_x, and CO_2.[35] In constructing the assumptions for the analysis cases in the earlier study, EIA reviewed the status of nonhydroelectric renewable generating capacity in the United States as of mid-2000, as well as State RPS and other mandates, green power programs, and other voluntary programs designed to encourage renewable electricity generation. On the basis of that review, it was assumed in the reference case and in all the analysis cases that 5.4 gigawatts of new nonhydroelectric renewable generating capacity would be built in the United States from 2000 to 2020, including 3.1 gigawatts of new wind capacity.

A similar review conducted for the current study resulted in substantial increases in the estimates for additions of wind and geothermal generating capacity, based on recent developments in California, Texas, and Washington State. As a result, the reference and analysis cases for this study assume that 7.5 gigawatts of new nonhydroelectric renewable generating capacity will be built in the United States from 2000 to 2020, including 5.1 gigawatts of new wind capacity and 0.3 gigawatts of new geothermal capacity.[36]

Reference Case

Because they cost more than fossil alternatives, renewable energy technologies are projected to account for very little new generating capacity through 2020 in the reference case, other than near-term builds in response to State RPS or other requirements. Generation from nonhydroelectric renewables is projected to increase from 87 billion kilowatthours in 1999 to 149 billion kilowatthours in 2020 (Table 24), and the nonhydroelectric renewable share of total U.S. electricity supply is projected to increase to 2.8 percent of net generation and 3.1 percent of retail electricity sales in 2020. Only biomass (including cogeneration) is projected to provide more than 1 percent of U.S. electricity sales by 2020 in the reference case. Geothermal energy is projected to provide about 0.6 percent of total generation in 2020, municipal solid waste/landfill gas about 0.6 percent, wind about 0.4 percent, and solar thermal and photovoltaics less than 0.1 percent each. Generation from conventional hydroelectric capacity is expected to remain essentially unchanged.

NO_x, SO_2, and Hg Emission Reduction Cases

The emission caps in the NO_x and SO_2 2008 cases are projected to have little or no effect on renewable energy use, with the exception of a small increase in co-firing of

Table 24. Renewable Fuels Market Projections in Two RPS Cases, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010 Reference Case	2010 RPS 20% Case	2010 RPS 10% Case	2020 Reference Case	2020 RPS 20% Case	2020 RPS 10% Case
Total Electricity Generation	3,706	4,597	4,573	4,591	5,294	5,252	5,285
Total Electricity Sales	3,312	4,147	4,117	4,141	4,788	4,707	4,771
Electricity Generation Using Renewables							
Conventional Hydroelectric Power	319	306	306	306	304	304	305
Geothermal	17	31	104	63	31	114	76
Municipal Solid Waste and Landfill Gas	27	28	35	32	32	40	37
Wood and Other Biomass	38	56	190	96	63	527	251
Dedicated Biomass	36	46	149	47	57	447	160
Biomass Co-firing	1	10	40	49	6	79	92
Solar (Thermal and Photovoltaic)	1	2	2	2	3	3	3
Wind	5	18	96	22	19	264	116
Total Renewables	406	441	732	521	453	1,253	788
Total Nonhydroelectric Renewables	87	136	426	215	149	948	483
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	6.3	6.2	6.2	6.5	6.2

Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

[35] For discussion of the renewable energy sources included, see pages 46-48 of the earlier EIA report.

[36] Small additions of new solar thermal capacity (107 megawatts) and central-station photovoltaic generating capacity (500 megawatts) are also assumed from 2000 to 2020. It is assumed that experience gained from solar and wind technology applications in foreign countries will contribute to reducing domestic capital costs through a learning effect. Based on a review of international renewable energy developments, it is assumed that 5 megawatts of photovoltaic capacity additions and 50 megawatts of wind capacity additions will contribute to the international learning effect in each year from 2000 through 2020. Other revisions from the earlier analysis include updated historical data and updated baseline projections for other renewable energy technologies.

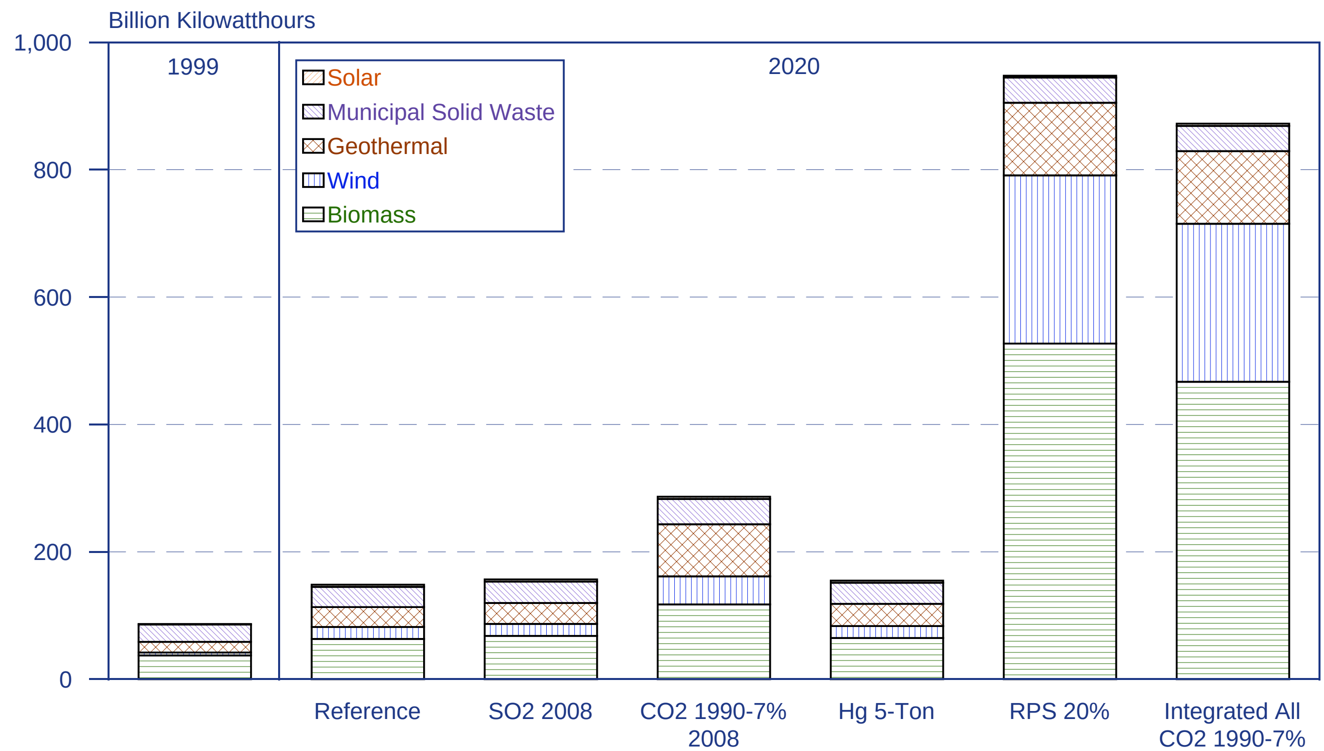
biomass with coal in the SO_2 2008 case in response to higher projected prices for low-sulfur coal (Figure 25). In the Hg 5-ton case, less than 1 gigawatt more new renewable energy generating capacity is projected to be added by 2020 than in the reference case, because the Hg cap can be met more cost-effectively by retrofitting and switching from coal to natural gas than by switching to more costly renewable energy technologies.

RPS Cases

Imposition of a 20-percent RPS is expected to lead to large increases in electricity generation from the least costly nonhydroelectric renewable fuels—biomass, wind, and geothermal. In the RPS 20% case, which requires that 10 percent of all U.S. electricity sales be provided by renewables other than conventional hydroelectricity by 2010, 15 percent by 2015, and 20 percent by 2020, total electricity generation from nonhydroelectric renewable energy sources is projected to increase to 948 billion kilowatthours in 2020. Because renewable generation is more expensive than coal- or natural-gas-fired generation, retail electricity prices are projected to reach 6.5 cents per kilowatthour by 2020, compared with 6.2 cents per kilowatthour in the reference case (Table 24). As a result, total electricity consumption in 2020 is projected to be 81 billion kilowatthours lower in the RPS 20% case than the 4,788 billion kilowatthours projected in the reference case. The natural gas share of total electricity sales in 2020 is projected to be 27 percent in the RPS 20% case, compared with 38 percent in the reference case, and the coal share of total sales in 2020 is projected to be 44 percent, compared with 49 percent in the reference case.

The total projected increase in nonhydroelectric renewable generation from 1999 through 2020 in the RPS 20% case is 861 billion kilowatthours. In contrast to the reference case, additions to renewable generating capacity are expected throughout the forecast period, consisting primarily of lower cost geothermal resources before 2010 (with little growth in geothermal capacity after 2010) and higher cost but more plentiful biomass and wind resources after 2010. Of the total increase in nonhydroelectric renewable generation over the forecast, 57 percent is expected to come from biomass, 30 percent from wind, 11 percent from geothermal, and 2 percent from landfill gas. Biomass (including cogeneration and co-firing with coal) is thus projected to become the primary renewable energy source for grid-connected U.S. electric power generation, providing 11 percent of all U.S. electricity sales in 2020 in the RPS 20% case. Biomass capacity in the electricity generation sector (excluding cogenerators) is projected to reach 61 gigawatts by 2020 in the RPS 20% case, compared with 2.4 gigawatts in the reference case, and generation from

Figure 25. Projected Electricity Generation from Nonhydroelectric Renewable Energy Sources, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2SO208P.D061201A, M2C7B08.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, and M2P7B08R_X.D070601A.

biomass co-fired with coal is projected to total 79 billion kilowatthours in 2020, compared with 6 billion kilowatthours in the reference case.[37]

Wind power adds the greatest amount of new renewable energy capacity in the RPS 20% case compared with the reference case and ranks second, after biomass, in increased generation.[38] Like biomass, wind capacity grows rapidly over the entire forecast period, increasing to 94 gigawatts by 2020 in the RPS 20% case, compared with about 8 gigawatts in the reference case.

U.S. geothermal capacity is projected to increase to 15 gigawatts by 2020 in the RPS 20% case, compared with 5 gigawatts in the reference case. However, there is considerable uncertainty about economically accessible supply of geothermal resources for sustained electric power production, and in the RPS 20% case, geothermal increases quickly, with most competitive geothermal resources developed by 2010. Only 1.3 gigawatts of new geothermal capacity is projected to be added after 2010.

Similarly, increased use of landfill gas provides additional relatively low-cost electric power in the RPS 20% case but is constrained by a limited number of landfills and the small size of individual landfill gas plants. As a result, compared with the reference case, additional new landfill gas capacity adds 1 gigawatt more generating capacity by 2020. Total municipal solid waste and landfill gas generating capacity in the electricity sector reaches 4.9 gigawatts by 2020 in the RPS 20% case.

Neither solar thermal nor photovoltaics is projected to add central-station generating capability in the RPS 20% case compared with the reference case. These technologies are both projected to remain more expensive than other alternatives through 2020. However, experience shows that some consumers and some utilities do select additional solar for reasons other than least-cost power supply; moreover, some jurisdictions may supplement the Federal RPS by offering rebates, tax credits, or other incentives not assumed here. As a result, additional residential and commercially installed solar units are possible. The projections in this report do not include off-grid photovoltaics. To the extent that off-grid markets are affected by increased costs of grid-supplied power or by other incentives, additional growth in off-grid photovoltaic generation growth could also occur.

In the RPS 10% case, which assumes an RPS half as stringent as in the RPS 20% case, projections for new renewable energy technologies are similar in overall direction to those in the RPS 20% case but show less new generating capacity powered by renewables. In the reference case 3.1 percent of U.S. electricity sales in 2020 are projected to be provided by nonhydroelectric renewables, meaning that an additional 7 percent is required in the RPS 10% case compared with 17 percent more in the RPS 20% case. In the RPS 10% case only 66 additional gigawatts are needed between 1999 and 2020 (excluding hydropower), or 39 percent of the total additions needed in the RPS 20% case. Because more coal-fired generating capacity is expected to be in service in 2020 in the RPS 10% case, biomass co-firing with coal is higher in 2020 in the RPS 10% case than in the RPS 20% case. In the RPS 10% case, electricity prices in 2020 are projected to average 6.2 cents per kilowatthour, the same as in the reference case (Table 24).

CO_2 1990-7% 2008 Case

The requirement to reduce CO_2 emissions alone results in increased renewable energy technology use compared with the reference case, including increased co-firing of biomass with coal in existing coal-fired plants and a slight increase in conventional hydroelectric power use. In the CO_2 1990-7% 2008 case, electricity prices in 2020 are projected to be 8.6 cents per kilowatthour, nearly 40 percent higher than projected in the reference case (Table 25). As a consequence, sales of electricity are projected to be 12 percent (nearly 600 billion kilowatthours) lower than in the reference case. Nonhydroelectric renewables (including cogeneration) are projected to provide almost 7 percent of U.S. electricity sales in 2020 in the CO_2 1990-7% 2008 case, and generation from conventional hydroelectric power is projected to be 5 billion kilowatthours higher than in the reference case in 2020, with 1.5 gigawatts of new hydroelectric capacity expected to be added by 2020.

Among renewable energy technologies, generation using biomass is projected to increase most in the CO_2 1990-7% 2008 case, to 118 billion kilowatthours in 2020 (Table 25), providing about 3 percent of total electricity sales. Generation from geothermal power increases to 82 billion kilowatthours in 2020, and generation from wind power increases to 44 billion kilowatthours in 2020.

Integrated All CO_2 1990-7% Case

The projections for renewable electricity generation in the integrated all CO_2 1990-7% case, which includes a 20-percent RPS, are generally similar to those in the RPS 20% case. However, because a 1990-7% cap on

[37]In an offline analysis using the assumptions of the RPS 20% case, EIA found that additional biomass co-firing beyond the 5-percent limit (up to 10 percent) could be economical as a fuel substitute for coal, assuming retrofit costs of $200 per kilowatt. Using the projected prices of coal, biomass, and renewable credits in 2015, approximately 100 billion kilowatthours of additional co-firing could be expected in 2015 beyond the level projected in the RPS 20% case. Because the RPS establishes a given level of renewable generation, however, the additional biomass co-firing would displace generation from other renewables rather than adding to the total.

[38]Because wind units generate electricity only when winds are sufficient, expected generation from a wind unit is less than for a comparably sized unit of biomass capacity.

power sector CO_2 emissions is also included, electricity prices are projected to be higher, total electricity sales are projected to be lower, and nonhydroelectric renewable energy use is projected to be lower than in the RPS 20% case. A slight increase in conventional hydroelectric power generation is also projected as a result of the CO2 cap (Table 26).

Integrated Sensitivity Cases

In the integrated moderate targets case, which assumes less stringent emissions caps than in the integrated all CO_2 1990-7% 2008 case and only a 10-percent RPS, nonhydroelectric renewables are projected to provide only about half as much electricity generation in 2020 as is projected in the integrated all CO_2 1990-7% 2008 case (Table 26). The 452 billion kilowatthours of nonhydroelectric renewable generation projected for 2020 in the integrated moderate targets case is similar to the level of 483 billion kilowatthours projected in the RPS 10% case.

In the integrated cost of service case, emissions allowances are assumed to have a zero cost basis in regions where electricity prices are based on cost of service. No RPS is assumed in this case. The projections for renewable generation in the integrated cost of service case (Table 26) are generally similar to those in the CO_2 1990-7% 2008 case (Table 25), but because overall

Table 25. Renewable Fuels Market Projections in the CO_2 1990-7% 2008 Case, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010		2020	
		Reference Case	CO_2 1990-7% 2008 Case	Reference Case	CO_2 1990-7% 2008 Case
Total Electricity Generation	3,706	4,597	4,280	5,294	4,963
Total Electricity Sales	3,312	4,147	3,803	4,788	4,204
Electricity Generation Using Renewables					
Conventional Hydroelectric Power	319	306	311	304	309
Geothermal	17	31	78	31	82
Municipal Solid Waste and Landfill Gas	27	28	36	32	40
Wood and Other Biomass	38	56	108	63	118
Dedicated Biomass	36	46	51	57	68
Biomass Co-firing	1	10	57	6	50
Solar (Thermal and Photovoltaic)	1	2	2	3	4
Wind	5	18	24	19	44
Total Renewables	406	441	559	453	596
Total Nonhydroelectric Renewables	87	136	248	149	287
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	8.8	6.2	8.6

Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

Table 26. Renewable Fuels Market Projections in Four Integrated Cases, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010					2020				
			Integrated Cases					Integrated Cases			
		Reference Case	All CO_2 1990-7%	Moderate Targets	Cost of Service	High Gas Price	Reference Case	All CO_2 1990-7%	Moderate Targets	Cost of Service	High Gas Price
Total Electricity Generation	3,706	4,597	4,305	4,347	4,408	4,306	5,294	5,025	5,014	5,064	4,886
Total Electricity Sales	3,312	4,147	3,830	3,870	3,956	3,838	4,788	4,313	4,318	4,453	4,188
Electricity Generation Using Renewables											
Conventional Hydroelectric Power	319	306	310	310	311	311	304	309	309	310	310
Geothermal	17	31	99	63	81	78	31	114	73	85	86
Municipal Solid Waste and Landfill Gas	27	28	36	36	36	36	32	40	40	40	40
Wood and Other Biomass	38	56	211	127	104	105	63	467	257	198	207
Dedicated Biomass	36	46	161	53	63	62	57	421	188	161	163
Biomass Co-firing	1	10	50	74	41	43	6	46	68	37	44
Solar (Thermal and Photovoltaic)	1	2	2	2	2	2	3	3	3	3	4
Wind	5	18	93	39	26	26	19	248	78	74	94
Total Renewables	406	441	750	577	559	558	453	1,181	761	710	740
Total Nonhydroelectric Renewables	87	136	440	267	249	247	149	872	452	400	430
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	8.6	8.2	7.7	8.6	6.2	8.0	8.2	7.9	9.3

Source: National Energy Modeling System, runs M2BASE.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

electricity demand is projected to be somewhat higher, renewables penetrate to a greater degree.

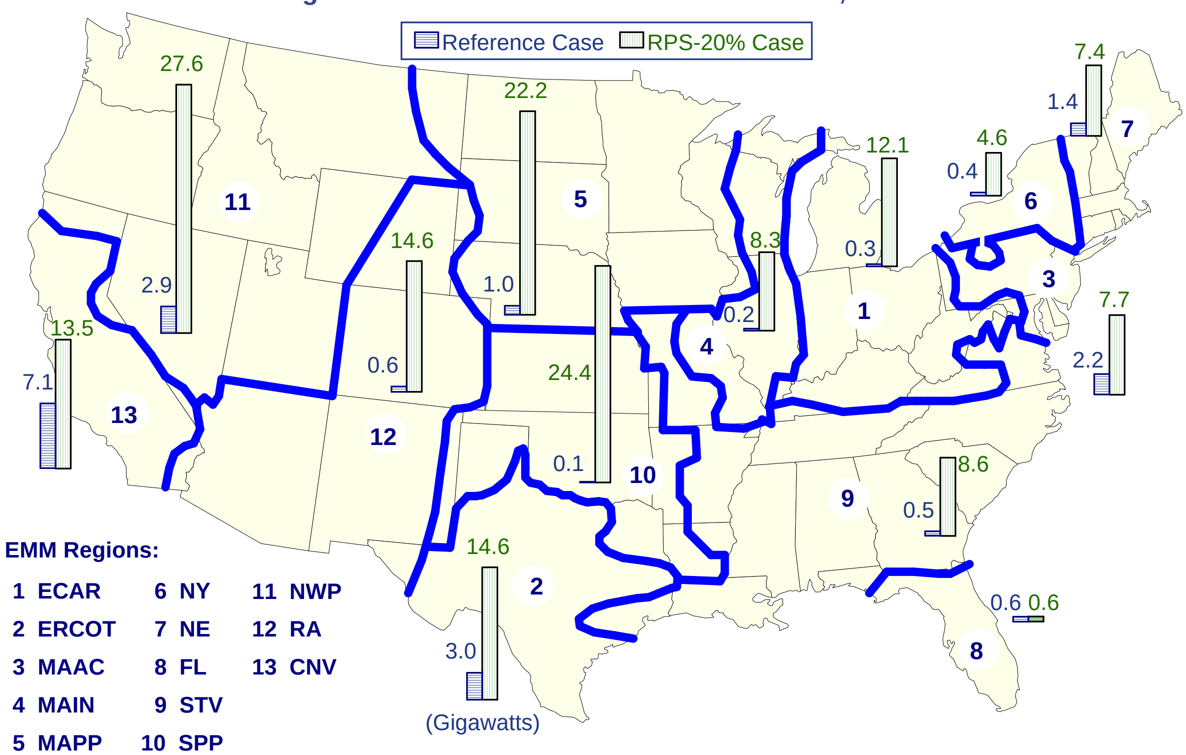
The integrated high gas price case assumes slower improvements in technologies for finding, developing, and delivering natural gas than are assumed for other cases in this analysis. It can be compared with the CO_2 1990-7% 2008 case, including the CO_2 reduction requirements but no RPS. Because of the higher natural gas prices, electricity generating costs are projected to rise more rapidly, and electricity prices in 2020 are projected to reach 9.3 cents per kilowatthour, higher than projected in any of the other analysis cases. As a result, renewables are projected to account for almost 18 percent of U.S. electricity sales by 2020, compared with 14 percent in the CO_2 1990-7% 2008 case, and nonhydroelectric renewables are projected to account for 10 percent of electricity sales by 2020.

Regional Impacts

Because opportunities for the development of new renewable energy supplies are not distributed evenly across the country, most of the projected increases in nonhydroelectric renewable electricity generation are expected in regions west of the Mississippi River (Figure 26). The West (EMM regions 11, 12, 13), which is projected to account for only about one-fifth of U.S. electricity sales in 2020 in the RPS 20% case, accounts for one-third of new qualifying renewable energy capacity. The Eastern Seaboard and Ohio Valley (regions 1, 3, 6, 7, 8, 9), which account for 56 percent of U.S. electricity sales, are expected to provide only one-fourth of new qualifying renewable energy capacity. The Midwest and Southwest from the Dakotas and Minnesota through Texas, which currently account for less than one-fourth of all U.S. electricity sales, are expected to account for more than 40 percent of new renewable energy electricity generating capacity in the RPS 20% case.

The large volumes of wind power projected in the RPS 20% case suggest that U.S. wind opportunities could be strained in meeting such large demands, primarily by exhausting wind resources, straining existing transmission networks, and encountering environmental and other siting objections. Using EIA estimates, four regions with relatively plentiful wind resources, the Upper Midwest (region 5), South Central (region 10), Northwest (region 11), and Southwest (region 12) are generally expected to be able to meet demands for new wind capacity. However, in order to meet the 20-percent RPS requirement, every region would fairly quickly exhaust its least-cost wind sites, and by the middle years of the forecast period nearly half of the regions with useful wind resources are projected to resort to their highest cost wind resources. Based on 1993 work done by the National Renewable Energy Laboratory, more recent experience, and contacts with experts, EIA assumes as

Figure 26. Cumulative Additions to Nonhydroelectric Renewable Generating Capacity by NEMS Electricity Market Module Region in the Reference and RPS-20% Cases, 2000-2020



Note: Capacity projections exclude cogenerators.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2RPS20_X.D070601A.

an intermittency constraint that 15 percent is the maximum percentage of any region's electricity sector generation that can be provided by wind and solar photovoltaic power without imposing notable additional costs on the system.[39] The far Southwest (region 12) is projected to be affected by such intermittency constraints, although the Upper Midwest (region 5), New England (region 7), South Central (region 10), and Northwest (region 11) approach them as well.

Uncertainties

There are significant uncertainties about the availability and quality of renewable energy resources, the future costs and performance of renewable energy technologies, and marketplace acceptance of the new technologies. National environmental concerns and renewables' perceived role in meeting those concerns add further uncertainty for renewable energy technology expectations. Also, the extent to which biomass can be efficiently co-fired with coal is still being tested.[40]

With little historical demand for large-scale use of renewables, resource availability, quality, accessibility, and sustainability are uncertain. Limited transmission capacity constrains geothermal and wind power located in remote areas. The extent to which large integrated electric power networks can incorporate intermittent power sources such as wind and solar photovoltaics is unclear. Cultural, environmental, and other market preference and acceptance issues could also affect renewable penetration.

Industry Employment Impacts

The analysis cases in this report can be expected to produce both broad macroeconomic and specific fuel sector impacts on employment. Macroeconomic impacts result from increased energy prices that will in turn affect industrial sectoral output, gross domestic product, overall productivity in the economy, and employment. In the primary fuel sectors, emission limits and higher prices are expected to alter the levels of overall and regional production of the fuels used for electricity generation and to change the levels of both direct employment and employment in associated industries and the surrounding infrastructure. In particular, the coal industry is expected to experience employment declines because of reduced coal production, and the natural gas and renewables industries are projected to show employment gains as electricity generators switch fuels. Relative to the reference case, projected employment gains in the oil and gas sectors in 2020 generally exceed projected employment losses in the coal sector in the Hg, NO_x, SO_2, and CO_2 cap cases.[41] In the RPS cases, increased activity and employment in the wind, biomass and geothermal industries lead to lower projected levels of production and employment in both the natural gas and coal industries.

Coal Industry

Between 1978 and 1999, the number of miners employed in the U.S. coal industry fell by 5.3 percent per year, from 246,000 to 79,000 (Figure 27). The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.4 percent over the same period. An additional factor contributing to the employment decline was the increased output from large surface mines in the Powder River Basin, which require much less labor per ton of output than mines located in the Interior and Appalachian regions. With improvements in productivity continuing over the forecast period, further declines in employment of 1.5 and 0.8 percent per year are projected from 1999 through 2010 and from 2010 through 2020, respectively. In absolute terms, coal mine employment is projected to decline in the reference case from 79,000 in 1999 to 67,000 in 2010 and 62,000 in 2020 (Table 27).

In the Hg 5-ton case, lower projected growth in U.S. coal consumption and production relative to the reference case combined with shifts in regional production patterns, leads to an expected overall decline in coal mining employment similar to that in the reference case forecast. Negative employment impacts resulting from the projected decline in U.S. coal production in the Hg 5-ton case are partially offset by shifts in production from high-productivity regions to regions with lower mining productivity. Relative to the reference case forecast, projected changes in regional production patterns are attributable to: (1) additional retrofits of flue gas desulfurization equipment (scrubbers) to reduce Hg emissions, making coal from the low-sulfur, high-productivity Powder River Basin region (Wyoming and Montana) less valuable relative to the reference case; and (2) a stringent cap on Hg emissions that leads to shifts in production to regions with low-Hg coals. As a result of the regional production shifts, labor productivity is projected to increase at an average rate of 1.8 percent per year in the Hg 5-ton case between 1999 and 2020, compared with a rate of 2.2 percent per year in the reference case. Thus, although coal production is projected to be 8 percent less in 2020 than in the reference case forecast (1,229 million tons in the Hg 5-ton case

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

[40]It is assumed in this analysis that biomass could be co-fired in coal plants up to 5 percent of total capacity. Co-firing above that level would require additional expenditures, whose costs are too uncertain to model at this time.

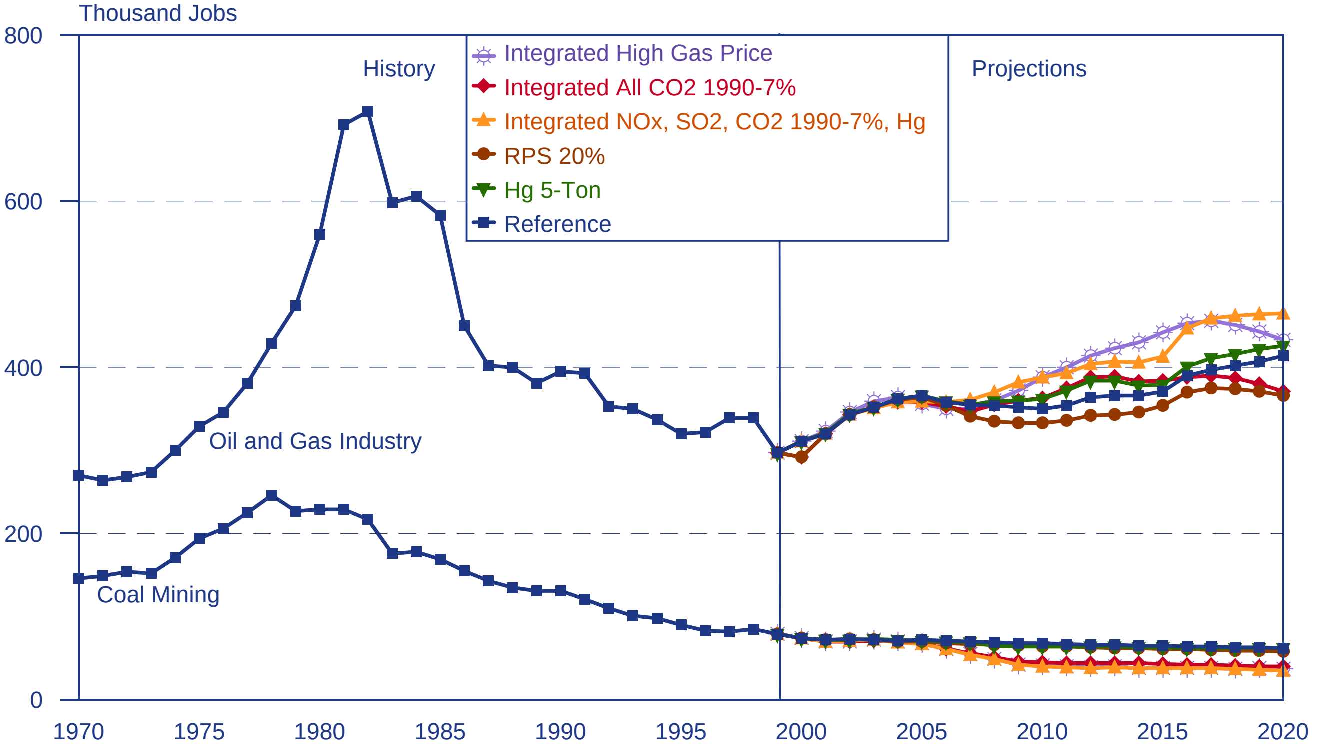
[41]For analysis of employment impacts in NO_x and SO_2 cap cases, see the results published in the earlier EIA report, pages 50-52.

compared with 1,340 million tons in the reference case), coal mine employment in 2020 is projected to be the same as in the reference case.

In the Hg 5-ton recycle case, it is assumed that 90 percent of the activated carbon used to remove Hg from power plant stack gases can be recycled and reused. Relative to the Hg 5-ton case, which assumes no recycling, the projected costs of removing Hg from the stack gas are substantially less, leading to less switching from high- to low-Hg coals and from coal to other fuels. U.S. coal production is projected to reach 1,261 million short tons by 2020, or 6 percent less than in the reference case, and coal industry employment is projected to fall to 61,000 by 2020, 2 percent less than the reference case forecast of 62,000 miners.

In the Hg MACT 90% case, it is assumed that all coal-fired generating units will be required to remove or capture 90 percent of the Hg from the coal received at the

Figure 27. Coal Mining and Oil and Gas Industry Employment, 1970-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, M2P7B08.D060801A, M2P7B08R_X.D070601A, and M2P7B08L.D060901A.

Table 27. Projected Impacts on Employment in the Coal Mining and Oil and Gas Industries, 2000-2020 (Thousand Jobs)

Industry	Analysis Case	1999	2005	2010	2020	Average Annual Growth, 2000-2020 (Percent)
Coal Mining.	Reference	79	71	67	62	-1.1
	Hg 5-Ton		71	64	62	-1.1
	RPS 20%		70	64	58	-1.5
	Integrated NO_x, SO_2, CO_2 1990-7%, Hg		67	40	35	-3.8
	Integrated All CO_2 1990-7%		68	45	40	-3.2
	Integrated High Gas Price		68	41	37	-3.5
Oil and Gas Extraction . . .	Reference	297	366	350	414	1.6
	Hg 5-Ton		366	362	426	1.7
	RPS 20%		364	333	366	1.0
	Integrated NO_x, SO_2, CO_2 1990-7%, Hg		359	388	465	2.2
	Integrated All CO_2 1990-7%		358	363	371	1.0
	Integrated High Gas Price		356	388	433	1.8

Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, M2P7B08.D060801A, M2P7B08R_X.D070601A, and M2P7B08L.D060901A.

plant, using maximum achievable control technology (MACT). Under this scenario, the incentive to switch to low-Hg coals is eliminated, because the costs of reduction are proportional to the percentage rather than the absolute amount of Hg removed. As a result, both coal production and employment patterns are not significantly different from those projected in the reference case.

In the RPS 20% case, projected U.S. coal consumption and production levels are slightly less than those in the reference case. In 2020, U.S. coal production is projected to reach 1,188 million short tons, 11 percent lower than in the reference case. As a result, U.S. coal mine employment is projected to decline from 79,000 miners in 1999 to 58,000 in 2020, 6 percent below the reference case projection for 2020.

In the integrated cases, lower levels of coal production in all supply regions relative to the reference case result in lower coal industry employment in all regions. In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, coal mine employment is projected to decline by 3.8 percent per year, to 35,000 by 2020. In the integrated all CO_2 1990-7% case, which includes an RPS, coal mine employment is projected to decline at a slightly slower rate of 3.2 percent per year, to 40,000 by 2020. The lower carbon allowance fee in this case, due to increased generation from renewable energy sources, leads to higher production of coal relative to the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Nevertheless, both of these cases show a considerably higher rate of decline in coal industry employment than does the reference case, where coal mine employment is projected to decline at a more moderate rate of 1.1 percent per year to 62,000 by 2020.

Although coal industry employment has declined substantially in recent years and is a relatively minor component of the current U.S. workforce, coal mines are typically in remote locations and provide a significant source of income and employment in rural areas of the country. According to data published by the U.S. Department of Labor, U.S. coal industry wages ranked in the top 20 of all major industries in 1999, with workers in the coal industry earning an average of $50,673 for the year, compared with an average of $33,244 for all U.S. industries taken as a whole.[42] In addition to the substantial contraction of the U.S. coal industry projected in the integrated cases, employment in the U.S. rail industry, which derives considerable revenues from coal shipments, also would be greatly affected.[43]

Oil and Gas Industry

Employment in the oil and gas industry has experienced a recent resurgence but is still lower than at its peak. In 2000, total industry employment in oil and gas production was 304,000 employees, up from 293,000 employees in 1999. Total oil and gas employment peaked in the U.S. in 1982, when employment reached 708,000 employees. Since 1982, employment has been generally falling, with minor upturns in 1990 (associated with the high oil prices accompanying the Gulf War) and in 2000, with a sharp resurgence in both world oil prices and domestic gas prices.

The oil and gas production industry comprises two segments: oil and gas production and oil and gas field services. Historically, most of the workers in the oil and gas industry have been employed in oil and gas field services rather than production. In 2000, oil and gas field service workers accounted for 172,000 employees, while production employment was 129,000. The year-to-year growth in oil and gas industry employment was entirely due to additional field service workers; employment in primary production actually fell by 4,000 jobs between 1999 and 2000.

Although oil production does not change dramatically in the reference case, total gas production is expected to increase rapidly, from 19.4 trillion cubic feet in 2000 to 29.5 trillion cubic feet by 2020. Producing more natural gas will require more employees, most of them employed in field services. In the reference case, total oil and gas employment is projected to reach 350,000 in 2010 and 414,000 in 2020. While the total number of oil and gas employees is projected to grow in the reference case, projected employment is 2020 is still less than the industry employment was as recently as 1986, when employment exceeded 450,000.

Controlling Hg emissions leads to greater use of natural gas and more jobs in the oil and gas industry. By 2020, industry employment is projected to be 426,000 in the Hg 5-ton case. Employment grows to as much as 465,000 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, 12 percent higher than employment in the reference case. Employment increases much more quickly in the early years. By 2010, employment in the integrated case is already 38,000 higher than projected in the reference case.

The introduction of an RPS lowers the growth in natural gas use and therefore lowers employment. In 2020, total industry employment in the RPS case is projected to be 366,000, 48,000 lower than projected in the reference case. Incorporating an RPS standard as part of an integrated policy including CO_2 emission reductions also lowers employment. In 2020, total employment in the oil and gas industry is projected to be 371,000 in the integrated all CO_2 1990-7% case, 20 percent lower than in the corresponding integrated case without the RPS.

[42]U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, "Covered Employment and Wages."

[43]See the earlier EIA report, pages 38 and 39, for a discussion of impacts on the rail industry.

Although controlling Hg either by itself or as part of an integrated policy is projected to stimulate oil and gas production to grow more quickly than it does in the reference case, the required growth in employment is not stronger than what has been experienced historically. Between 1980 and 1981, average oil and gas employment grew by more than 130,000 in a single year. This suggests that the projected expansion in oil and gas production workers is feasible across all scenarios, even those that projected strong increases in natural gas demand.

Renewable Fuels Industry

Depending on the emissions to be reduced, employment in U.S. renewable energy industries could either remain unaffected or be significantly increased by changes in U.S. emissions control policies. Renewable energy employment is not expected to increase under scenarios designed solely to reduce NO_x, SO_2, or Hg emissions from electric power plants because no notable increases in use of renewable energy resources are expected in those cases. In addition, most renewables—geothermal, hydroelectric, landfill gas, solar, and wind, for example—do not support separate renewable energy extraction industries. Only biomass involves notable labor in energy production, such as for energy crops or for separating, preparing, and transporting various agricultural and forest wastes.

Scenarios calling for significant reductions in CO_2 emissions or imposing a 10- or 20-percent national RPS could be expected to induce significant employment in manufacturing power plant equipment, for plant construction, and in ongoing operations and maintenance. Non-U.S. suppliers as well as domestic manufacturers would likely also provide significant shares of equipment for U.S. renewable energy installations, particularly for turbine generators.

Macroeconomic Impacts

The imposition of new, more stringent emissions caps on electricity generators is expected to affect the U.S. economy primarily through an increase in delivered energy prices. Higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher cost energy, the change would also tend to lower the productivity of other factors in the production process because of a shift in the prices of capital and labor relative to the price of energy. Moreover, a rise in energy prices would raise non-energy intermediate and final product prices and introduce cyclical behavior in the economy, resulting in output and employment losses in the short run. In the long run, however, the economy can be expected to recover and move back to a more stable growth path.

The macroeconomic assessment presented in this section evaluates one of the integrated cases discussed in Chapter 2, the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, but from two different implementation viewpoints. The integrated NO_x, SO_2, CO_2 1990-7%, Hg case is discussed because it incorporates all of the stringent emission caps analyzed in this report. It requires that power sector emissions of NO_x and SO_2 be reduced to 75 percent below their 1997 level, that Hg emissions be capped at 5 tons per year (90 percent below their 1997 level), and that CO_2 emissions be reduced to 7 percent below their 1990 level. Two implementation systems are presented to indicate that the manner of implementation will affect the overall impacts on the economy:

- The first case assumes a marketable emission permit system, with a no-cost allocation of the permits. In meeting the targets, power suppliers are free to buy and sell allowances at a market-determined price for the permits, which represents the marginal cost of abatement of any given pollutant.
- An alternative form of permit system would auction the permits to power suppliers. The price paid for the auctioned permits would equal the price paid for traded permits under the no-cost allocation system used for this study. However, the two systems imply a different distribution of income. The funds collected through the auction are assumed to be recycled to consumers through a lump-sum transfer.

Table 28 summarizes the projected macroeconomic impacts under these two implementation strategies.

With a No-Cost Allocation of Permits to Power Suppliers

Energy prices are projected to continue increasing relative to the reference case projections through the target year (2008) of the emission reduction. The most rapid increases in energy prices are projected during the first 10 years of the forecast period, because the power sector is expected to turn from coal to natural gas to comply with the CO_2 emission caps. Energy prices are projected to continue rising after 2010, but the rate of increase is expected to be more gradual.

In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the aggregate prices for the economy are projected to rise steadily above the level projected in the reference case. Higher projected electricity and natural gas prices initially affect only the energy portion of the consumer price index (CPI). The higher projected energy prices are expected to be accompanied by general price effects as they are incorporated in the prices of other goods and services. In this case, the level of the CPI is projected to rise steadily through 2010, reaching 0.9 percent above the reference case. Between 2010 and 2020, the level of the CPI does not increase further, and it remains 0.9 percent above the reference case in 2020.

Higher energy prices would affect both consumers and businesses. Households would face higher prices for energy and the need to adjust spending patterns. Rising expenditures for energy would take a larger share of the family budget for goods and service consumption, leaving less for savings. Energy services also represent a key input in the production of goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the prices of all intermediate goods and final goods and services in the economy. Capital, labor, and production processes in the economy would need to be adjusted to accommodate the new, higher set of energy and non-energy prices. These transition effects tend to dominate in the short run but dissipate over time.

Expectations on the part of power suppliers and consumers of energy play a key role. On the part of the

Table 28. Projected Macroeconomic Impacts in the Reference and Integrated NO_x, SO_2, CO_2 1990-7%, Hg Cases Under Two Emission Permit Allocation Schemes, 2010 and 2020

Projection	1999	2010	2020
Real Gross Domestic Product (Billion 1996 Dollars)			
Reference	8,876	12,667	16,515
No-Cost Allocation of Permits		12,555	16,493
Auction of Permits with Recycling to Consumers		12,565	16,456
Real Gross Domestic Product (Percent Change from Reference Case)			
No-Cost Allocation of Permits		-0.9	-0.1
Auction of Permits with Recycling to Consumers		-0.8	-0.4
Consumer Price Index (Index, 1982-1984 = 100)			
Reference	167.0	220.0	295.0
No-Cost Allocation of Permits		221.9	297.5
Auction of Permits with Recycling to Consumers		221.9	298.3
Consumer Price Index (Percent Change from Reference Case)			
No-Cost Allocation of Permits		0.9	0.9
Auction of Permits with Recycling to Consumers		0.9	1.1
Unemployment Rate (Percent)			
Reference	4.22	4.94	4.28
No-Cost Allocation of Permits		5.34	4.23
Auction of Permits with Recycling to Consumers		5.28	4.26
Unemployment Rate (Change in Rate from Reference Case)			
No-Cost Allocation of Permits		0.40	-0.05
Auction of Permits with Recycling to Consumers		0.34	-0.02
Disposable Income (Billion 1996 Dollars)			
Reference	6,363	8,928	11,842
No-Cost Allocation of Permits		8,822	11,789
Auction of Permits with Recycling to Consumers		8,861	11,819
Disposable Income (Percent Change from Reference Case)			
No-Cost Allocation of Permits		-1.2	-0.4
Auction of Permits with Recycling to Consumers		-0.8	-0.2
Non-agricultural Employment (Million Employed)			
Reference	128.5	149.7	165.1
No-Cost Allocation of Permits		148.4	165.2
Auction of Permits with Recycling to Consumers		148.6	165.1
Non-agricultural Employment (Change from Reference Case, Million Employed)			
No-Cost Allocation of Permits		-1.3	0.1
Auction of Permits with Recycling to Consumers		-1.1	0.0

Note: All percent changes and changes from the reference case are rounded to one decimal point.
Source: Simulations of the Standard & Poor's DRI Macroeconomic Model of the U.S. Economy.

power suppliers, current investment decisions depend on expectations about future markets. They will make decisions by reviewing each technology's current and future capital, operations and maintenance, and fuel costs. Both current and expected future costs are considered because generating assets require considerable investment and last many years. These forward-looking decisions help to moderate the ultimate price effects passed on to the rest of the economy. The views of consumers and businesses are also influenced by expectations of future price changes. Inflationary expectations on the part of consumers and businesses are characterized as a function of recent rates of increase in prices and spending. Thus, although expectations are important, they are based in general on recent changes, not on forward-looking expectations in the absence of change.

In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the unemployment rate is projected to be 0.4 percentage points above the reference case in 2010. Along with the rise in inflation and unemployment, real output of the economy is projected to decline. Real gross domestic product (GDP) is projected to be 0.9 percent lower relative to the reference case in 2010, and employment in non-agricultural establishments is projected to be lower by 1.3 million jobs. Similarly, real disposable income is expected to be 1.2 percent lower than the reference case level. The economic impacts peak early in the forecast period, by 2010, in response to the rapid rise in energy prices as the target level of emissions is reached in 2008.

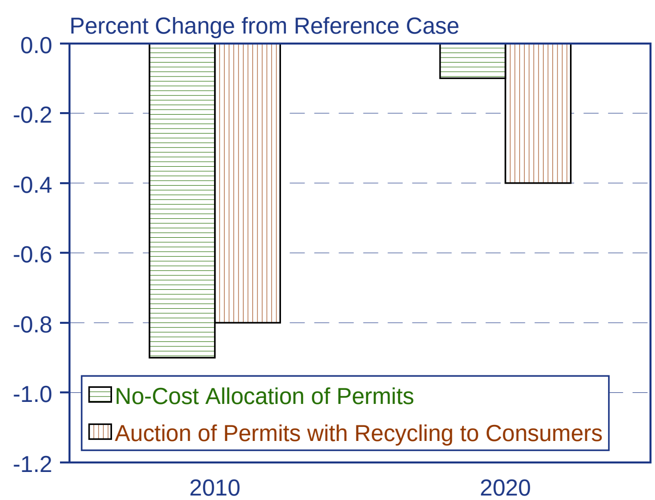
As the economy adjusts to higher energy prices, inflation begins to subside in the forecasts after 2010. At the same time, the economy begins to return to its long-run growth path. By 2020, real GDP is projected to be only 0.1 percent below the reference case level, and both employment and the unemployment rate are near reference case levels.

With an Auction of Permits with Recycling to Consumers

In the no-cost allocation system, there would be a redistribution of income flows between power suppliers in the form of purchases of emission permits. There would be no net burden on the power suppliers as a whole, only a transfer of funds among firms. While all firms are expected to benefit from trading, the burden would vary among firms. With a Federal auction system, in contrast, there would be a net transfer of income from power suppliers to the Federal Government. In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the magnitude of the transfer would be approximately $46 billion (1996 dollars) in 2010 and almost $60 billion in 2020. The key question at this juncture turns on the use of the funds by the Federal Government. If the funds were returned to the power suppliers, the effect would be the same as in the no-cost allocation scheme, but with the Federal Government establishing the permit market mechanism. Another use of the funds might be to return them to consumers either in the form of a lump-sum transfer or in the form of a personal income tax cut, partially compensating consumers for the higher prices paid for energy and non-energy goods and services.

Relative to the no-cost allocation of permits, an auction that transfers funds to consumers in a lump sum would help to maintain their level of overall consumption. With the transfer, however, total investment declines relative to the no-cost allocation system. The two effects tend to counterbalance each other, but not completely. Returning collected auction funds to the consumer has a slightly more positive effect than the negative effect on investment through 2010. In 2010, real GDP is projected to be 0.9 percent below the reference case under the no-cost allocation, but this is moderated to a difference of 0.8 percent when the funds are recycled to consumers (Figure 28). However, in the period between 2010 and 2020, investment rebounds faster in the no-cost allocation case, and this feature contributes significantly to the faster recovery back to the baseline. By 2020, real GDP under the no-cost allocation of permits is 0.1 percent below the reference case, but with the recycling of funds to consumers, real GDP is 0.4 percent below the reference case. There is a fundamental tradeoff in the time profile of the impacts in the two cases. Returning auctioned permit revenues to consumers ameliorates the near-term adverse impacts, but this case does not return

Figure 28. Changes in Projected U.S. Gross Domestic Product with Multiple Emissions Reduction Requirements, 2010 and 2020



Source: National Energy Modeling System, run M2P7B08. D060801A, and simulations of the Standard & Poor's DRI Macroeconomic Model of the U.S. Economy.

as quickly to the reference case as does the case with a no-cost allocation of permits.[44]

Other approaches would recycle the revenues from auctioned permits back to either consumers or business through a reduction in marginal tax rates on capital or labor.[45] Unlike the no-cost allocation or the lump-sum payment to consumers, this approach may lower the aggregate cost to the economy by shifting the tax burden away from taxes on labor and capital toward the taxation of an environmental pollutant. Most often research on this method is based on a general equilibrium approach, where all factors are assumed to be utilized fully, as in the work by Goulder, Parry, and Burtraw.[46]

[44]For further discussion of recycling issues for an economy in transition, see Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), Chapter 6, "Assessment of Economic Impacts."

[45]For a discussion of the relative merits of alternative policy instruments, see R. Perman, Y. Ma, and J. McGilvray, "Pollution Control Policy," in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

[46]L.H. Goulder, I.W.H. Parry, and D. Burtraw, "Revenue-Raising Versus Other Approaches to Environmental Protection: The Critical Significance of Pre-existing Tax Distortions," *RAND Journal of Economics,* Vol. 28. No. 4 (Winter 1997), pp. 708-731.

5. Comparisons with Other Studies

Introduction

This chapter is divided into two sections. The first describes selected studies in which a renewable portfolio standard (RPS) has been modeled as a policy option to increase electricity generation from eligible renewable sources. The results of those studies are compared with those obtained in the RPS cases of the present study. The second section describes another multiple emission reduction analysis, which examined potential reductions of mercury (Hg) emissions in combination with reductions in emissions of sulfur dioxide (SO_2) and carbon dioxide (CO_2). Comparisons of studies targeting emissions of SO_2, nitrogen oxides (NO_x), and CO_2 (but not Hg), singly and in various combinations, were included in the earlier analysis by the Energy Information Administration (EIA).[47]

As there are many different types of RPS and various mechanisms for their implementation, there are many analyses of different RPS proposals. Many were done more than a few years ago, making valid comparisons difficult.[48] Others did not focus on the electricity generation sector.[49] Very few modeled a 20-percent RPS target, and none modeled an RPS and multiple emission reductions jointly.[50] Analytical modeling of potential reductions in Hg emissions is relatively new, and comparative analyses may number as few as one. In this chapter, the results of EIA's current analysis are compared with results from three other RPS analyses and one analysis of Hg emission reductions:

- An EIA analysis in the *Annual Energy Outlook 2000* (*AEO2000*) that included sensitivity cases modeling an RPS[51]
- An RPS analysis by the Union of Concerned Scientists (UCS), also published in 1999[52]
- An RPS analysis sponsored by the Tellus Institute (Tellus), published in 1997[53]
- An Hg emission reduction analysis by the U.S. Environmental Protection Agency (EPA), published in 1999.[54]

The EPA mercury study was part of a larger analysis of multiple emission reductions, in which various reductions in SO_2 and CO_2 emissions were modeled in combination with Hg emission reductions.[55] No RPS analysis was included in the study.

[47]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR/OIAF/2000-05 (Washington, DC, December 2000), Chapter 6.

[48]Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Tellus Institute, and Union of Concerned Scientists, *Energy Innovations 1997: A Prosperous Path to a Clean Environment* (Washington, DC, June 1997).

[49]S. Bernow et al., *America's Global Warming Solutions* (Washington, DC: World Wildlife Fund and Energy Foundation, August 1999). This study focused on CO_2 reductions. In an offline analysis, a Systems Benefits Charge of 2 mills per kilowatthour induced a 10-percent share of generation from new renewable sources. Those generators were then modeled as planned capacity, and a 10-percent RPS was achieved.

[50]Interlaboratory Working Group. 2000. *Scenarios for a Clean Energy Future*, ORNL/CON-476 and LBNL-44029 (Oak Ridge, TN: Oak Ridge National Laboratory, and Berkeley, CA: Lawrence Berkeley National Laboratory, November 2000). This study modeled an RPS through an extension of the 1.5 cents per kilowatthour production tax credit (PTC) for wind and dedicated biomass installed by 2004 and a 1.0 cent per kilowatthour PTC for biomass co-firing in 2000-2004. The study's Advanced Scenario included an RPS, represented as an additional 1.5 cents per kilowatthour PTC for 2005-2008, with carbon reduction scenarios. The analysis covered all end-use sectors.

[51]Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), p. 18.

[52]S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999). See also S. Clemmer, D. Donovan, and A. Nogee, *Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future*, Phase I (Cambridge, MA: Union of Concerned Scientists, June 2001), web site www.ucsusa.org. The *Clean Energy Blueprint* analysis focuses on policies designed to improve energy efficiency and to develop renewable resources, including a 20-percent RPS by 2020. Projected savings on consumers' energy bills begin to outstrip the costs of the program in 2010, and net benefits over the period 2002-2020 total $31 billion (1999 dollars). Phase II, forthcoming in summer 2001, will address emission reduction strategies and improvements in power plant efficiency.

[53]S. Bernow, W. Dougherty, and M. Duckworth, "Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard," *The Electricity Journal* (May 1997).

[54]U.S. Environmental Protection Agency, Office of Air and Radiation, *Analysis of Emissions Reductions Options for the Electric Power Industry* (Washington, DC, March 1999), web site www.epa.gov/capi/multipol/mercury.htm.

[55]The EPA is currently working on a comprehensive update of this modeling effort.

Models produce different results for many reasons. The following are some of the most important:

Representation of the energy system. All the models used in the studies compared here include detailed representations of the electricity generation sector, but there are some differences in terms of interaction with other energy sectors. For example, EIA's National Energy Modeling System (NEMS) is a comprehensive model, integrating not only energy supply but also end-use demand and macroeconomic feedback. NEMS endogenously projects consumer demand for each fuel and the prices at which the fuels are expected to be supplied in order to meet demand. Changes in assumptions, such as the addition of pollution control equipment, alter electricity dispatch decisions, leading to a fuel price response. NEMS then recalculates projections of fuel prices and consumers' response to them, based on the projected changes in the electricity generation sector. In contrast, EPA's Integrated Planning Model (IPM) does not endogenously integrate fuel supply and demand. Thus, the EPA analysis does not include an endogenous fuel price response to altered demand.[56] Neither the UCS analysis nor the Tellus analysis, despite being based on NEMS, included an endogenous price response to changing fuel demands in the generation sector, because only the Electricity Market Module was run.

Assumptions regarding costs and performance of pollution control technologies. The EIA and EPA analyses used similar cost assumptions for various control technologies; however, because the Hg targets are so stringent, often requiring large investment in control equipment, even minor differences in cost can affect the choice of retrofit equipment. Because information about the technologies to reduce Hg emissions is incomplete, there are differences in assumptions concerning practicable retrofit options. EIA's analysis allowed for as many as 32 distinct plant retrofit configurations, and EPA's analysis modeled 16 retrofit combinations; but it is unclear how many practicable combinations there are. Further, new research has been conducted since the time of the EPA report, resulting in some revisions to cost and performance parameters for Hg control technology.

Assumptions regarding the extent of renewable resources and the penetration of renewable technologies. Models may reasonably differ over the shape of the supply functions at more ambitious RPS levels. For example, the UCS analysis was more optimistic than EIA's analysis with regard to the technological costs of wind turbines as supply resources are depleted. As a result, much more wind generation was projected in the UCS study. The optimal rate of biomass co-firing at utility coal units is debatable, ranging not only in magnitude (from 5 percent to 10 percent) but also in the pace of deployment. NEMS models grid-connected central-station and distributed generators in its Electricity Market Module as well as distributed generation in its Residential Demand and Commercial Buildings Modules.[57] Other studies project increased supply of solar technologies through a variety of off-grid applications.

Assumptions regarding the effects of new renewable resources on existing industry reliability standards. Because of the intermittent nature of both wind and solar resources, their contribution to regional reliability is assumed to be less than their total capability. Under the more ambitious RPS targets, the share of generation from intermittent sources can approach maximum industry standards, which vary at the regional level. Reliability standards, determined through loss-of-load probability calculations, enable regions to meet their generating reserve margins. NEMS assumes that the maximum contribution of renewable generators is capped at 15 percent,[58] whereas other models may allow greater shares from intermittent sources.

Differences in reference scenarios. Energy models are heavily dependent on assumptions of baseline values for critical variables, the most important of which are fuel prices, especially natural gas, and the rate of growth for electricity demand. The studies compared below were conducted at various times over a five year period from 1997 to 2001, and consequently the studies begin from different values. Wellhead natural gas prices in 1998 and 1999 were both lower in real terms than in 1997, but prices were sharply higher in 2000.[59] Consequently, EIA's study uses a much higher wellhead price for the near term in its reference case. Generally, electricity demand growth has accelerated over the last several years, and the studies project increasingly higher growth rates as the reference year of the study moves forward. The Tellus study, using the *AEO1996* (initial forecast year 1996), and the UCS study, using the *AEO1998* (initial forecast year 1998), both assume demand growth rates of 1.4 percent, as does the *AEO2000* sensitivity case (initial forecast year 2000); and

[56]The EPA analysis did provide for slight increases in price at higher consumption levels, but the model results never reached those levels.

[57]Energy Information Administration, *Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO66(2001) (Washington, DC, January 2001); Energy Information Administration, *Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO67(2001) (Washington, DC, January 2001); see also E. Boedecker, J. Cymbalsky, and S. Wade, "Modeling Distributed Electricity Generation in the NEMS Buildings Models," (Washington, DC, September 2000), http://www.eia.doe.gov/oiaf/analysispaper/electricity_generation.html.

[58]In the present EIA analysis, only one region (Rocky Mountain-AZ) is projected to reach the maximum.

[59]Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(00) (Washington, DC, July 2001), Table 6.8.

the current EIA study used a growth rate of 1.8 percent (initial forecast year 2000). EPA's Hg analysis assumed a 1.6-percent growth rate from 1997 to 2000 and a 1.8-percent growth rate from 2001 to 2010.

On the other hand, the analyses compared here have a number of similarities. The three RPS studies were based on the NEMS Electricity Market Module, with customized modifications to its Electricity Capacity Planning Module. Although the RPS targets analyzed ranged from 4 percent to 20 percent, the technological menu available to each model was similar, regional resource attributes were roughly similar, and electricity prices in competitive regions were assumed to depend on the marginal cost of generation. For Hg emissions, EPA's IPM model relied on a representation of coal supply similar to the Coal Market Module of NEMS, and abatement strategies were assumed to rely on the same types of control technologies applied to similarly representative plant configurations. Baseline assumptions about the generation fuel mix and Hg emissions in the two studies are comparable.

RPS Analyses

EIA's *AEO2000* Analysis of a 7.5-Percent RPS

EIA analyzed a 7.5-percent RPS target as a sensitivity case in the *AEO2000*. With the RPS targets set at 2.4 percent for the years 2000-2004, then increasing linearly to 7.5 percent in 2010 (see Table 29), the case replicated the targets called for in the Comprehensive Electricity Competition Act (CECA). An interesting feature of the CECA RPS was a cap of 1.5 cents per kilowatthour on the price of renewable credits. For the *AEO2000* analysis, EIA modeled three sensitivity cases, one of which removed both the 1.5-cent cap and a sunset provision, which would have allowed the 7.5-percent RPS target to lapse after 2015 (the "no cap, no sunset" case). The effects of the RPS were isolated by removing the renewable credit cap and using reference case assumptions about the regulation of wholesale electricity markets, rather than competitive assumptions.

In the no cap, no sunset case, EIA found that about 30 gigawatts of wind, 9 gigawatts of dedicated biomass, and 5 gigawatts of geothermal capacity were added to reference case projections by 2020 to meet the 7.5-percent RPS target. Electricity prices in 2020 were projected to be 0.3 cents higher than in the reference case. In two other RPS sensitivity cases, both of which included either the 1.5-cent cap on renewable credit prices or the sunset provision, it was projected that the 7.5-percent RPS target would not be achieved. A maximum 1.5-cent renewable credit was found to be largely insufficient to overcome the cost advantages enjoyed by fossil technologies and meet the relatively modest 7.5-percent target.

UCS Analysis of a Range of RPS Targets

In January 1999, UCS published a study analyzing several RPS proposals under consideration in Congress. The proposals ranged from modest RPS targets of 4 percent by 2010 (Schaefer bill, H.R. 655) to 20 percent by 2020 specified in the most ambitious proposal (Jeffords bill, S. 687) and included the CECA proposal of 7.5 percent.[60] As such, the proposals represented increases in electricity generation from renewable sources ranging from 10 percent to about 500 percent above reference levels.

Like the EIA analysis, the UCS modeled a national RPS requirement with trading of credits. UCS employed a model called RenewMarket, patterned after the Electricity Capacity Planning (ECP) module in NEMS. Like the ECP, RenewMarket compared the long-term costs of various technologies and allocated sufficient capacity to meet regional electricity demand at the lowest cost. Unlike the ECP, RenewMarket incorporated different assumptions about several renewable technologies. The forecast horizon for the UCS analysis was 10 years longer than that of NEMS, extending to 2030.

UCS incorporated four changes to RenewMarket with regard to wind and geothermal energy. UCS included an industrial growth rate penalty in the form of a capital cost multiplier that was applied when the growth in installed domestic capacity exceeded 20 percent per year on average over the previous 3 years. UCS also imposed a capital cost penalty on wind as the penetration of wind increased in a given region. The cost approximated the value of adding a combustion turbine to provide firm power as the capacity credit for wind declined at higher penetrations. UCS allowed RenewMarket to develop lower class wind resources at lower cost where it was economically feasible. Finally, UCS increased the amount of geothermal capacity that RenewMarket would allow to be built in a given year, from 300 megawatts to 1,000 megawatts.

The UCS analysis also used different assumptions in regard to the learning curve that provides for a reduction in capital costs as a technology penetrates the market. UCS assumed that exogenous factors, such as research and development and international growth, would spur further capital cost reductions across technology types. The NEMS assumption is more restrictive, limiting the international learning effect to a maximum of one unit per technology per year, regardless of the amount of international builds. RenewMarket also reduced the price response to declining demand for

[60] In the UCS analysis, the RPS was 5.5 percent, reflecting the original RPS goal of the Clinton Administration.

natural gas, resulting in higher prices and fewer builds of new gas-fired generators than would be obtained in the ECP.[61]

The UCS study found that the average price of electricity under an RPS increased from reference levels. Under the Jeffords proposal, a 20-percent RPS, UCS found that average electricity prices fell by 13 percent between 1998 and 2020, down from the 18-percent decline projected under reference conditions.[62] UCS also found that natural gas prices increased by less under the Jeffords proposal than under the other RPS targets examined over the forecast period. Although the 20-percent RPS target produced the highest net costs,[63] reaching a peak in 2024, costs were projected to decline rapidly over the remainder of the forecast horizon to 2030.

Tellus Analysis of a 4-Percent RPS in 2010

Two years before the UCS study, the Tellus study used NEMS to analyze an RPS proposal contained in Rep. Schaefer's bill, H.R. 655. That bill called for eligible renewable generation to supply 2 percent of total electricity generation in 2000, 3 percent by 2005, and 4 percent by 2010, making it one of the more modest RPS proposals. Basing their analysis on EIA's 1996 *AEO* reference case, the authors used the standard method of inducing additional renewable generation by imposing a negative "shadow price" on the operating cost of eligible renewable generation. By decrementing operating costs in this way, the RPS target was eventually met, and the shadow price reflected the national credit trading price.

The results of the Tellus analysis were similar to those of other studies. The authors found that meeting a 4-percent RPS target by 2010 increased average electricity prices by 0.03 cents per kilowatthour over reference levels. The shadow price peaked in 2005 at about 1.25 cents per kilowatthour, falling to about 1.0 cent in 2010. Most of the new generation came from wind sources, with geothermal also increasing its share significantly. These renewable sources tended to displace natural gas generation, although small amounts of coal and oil were also removed. At the regional level, California-Southern Nevada and the Pacific Northwest each accounted for about one-fourth of the new renewable generation, with the Rocky Mountain area, Texas, New England, and the Mid-Atlantic also projected to have significant increases. These regions combine high avoided costs with favorable renewable resource opportunities in responding to the constraints of the modeled RPS.

Comparison of RPS Results

The RPS targets and implementation schedules modeled for the EIA, UCS, and Tellus studies are shown in Table 29. Table 30 shows detailed results, where available. The current EIA study models a 20-percent RPS by 2020, as did the UCS analysis of the Jeffords bill. The RPS target in EIA's *AEO2000* no cap, no sunset case was lower, 7.5 percent (by 2010), and the Tellus analysis assumed the 4-percent requirement (by 2010) proposed in the Schaefer bill. Also shown in Table 30 are the results for EIA's integrated RPS case with reductions for four targeted emissions. The Tellus study is not included in Table 30 because of a lack of comparable quantitative results.

Differences in baseline values, largely attributable to the timing of the studies, influenced the ease with which the RPS target could be met. EIA's reference case for the current study, based on the *AEO2001*, estimated that generation from eligible renewables was 80 billion kilowatthours, accounting for only 2.1 percent of total generation in 2000; the UCS study, based on *AEO1998*, projected a 2.9-percent share for renewables in 2000. The Tellus study, which did not include electricity generated by cogenerators for their own use, projected that renewables would account for 1.9 percent of total electricity generation in 2000. In addition, because the studies used different base years, there were significant differences in the initial (year 2000) prices of natural gas: UCS, $2.59 per million Btu to electricity generators; EIA (*AEO2000*), $2.20 per million Btu; and EIA (current study), $3.46 per million Btu at the wellhead (values converted to 1999 dollars).

Table 29. Assumptions for Renewable Portfolio Standards and Timing in Four Analyses

Study	RPS Target and Implementation Schedule
EIA, Current Study. .	5% by 2005, 10% by 2010, 20% by 2020
EIA, *AEO2000*	2.4% 2000-2004, increasing to 7.5% by 2010
UCS.	5% by 2005, 10% by 2010, 20% by 2020
Tellus	2% by 2000, 3% by 2005, and 4% by 2010

Sources: **EIA, Current Study:** National Energy Modeling System, run M2RPS20_x.D070601A. **EIA, *AEO2000*:** National Energy Modeling System, run RPS2KFUL.D100699B. **UCS:** S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999). **Tellus:** S. Bernow, W. Dougherty, and M. Duckworth, "Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard," *The Electricity Journal* (May 1997).

[61] For example, in 2020 RenewMarket projects a price decline of $0.015 per million Btu for each quadrillion Btu reduction in cumulative consumption. Prior to 2005, changes in gas consumption are assumed to have no effect on price in the UCS analysis.

[62] The UCS analysis used the 1998 *AEO* reference case, which projected a decline of 1.1 cents per kilowatthour in average U.S. electricity prices between 1998 and 2020.

[63] Net cost was defined as increased expenditures on electricity minus savings from lower natural gas prices.

The different models projected similar responses to the RPS constraints. Generally, natural gas prices were projected to fall, CO_2 emissions were projected to be reduced in proportion to the RPS target, and NO_x and Hg emissions were projected to be reduced slightly. SO_2 emissions tended to remain fairly constant, with each study representing the CAAA90 SO_2 cap of 8.95 million tons.

The RPS increases the price of electricity on average, mostly because these generating sources are more expensive than coal- or natural-gas-fired generation, and all the studies report prices that rise in proportion to the target modeled. EIA reports an increase of about 4 percent in the RPS case in 2010, and UCS reports an increase of 2 percent. The larger price impact in EIA's RPS study arose from different assumptions about

Table 30. Comparison of Key RPS Results

Item	EIA, Current Study			EIA, *AEO2000* RPS Case	UCS[a]
	Reference	RPS 20%	Integrated All CO_2 1990-7%		
2005 Projections					
Coal-Fired Capacity (Gigawatts)	313	312	312	312	285
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,159	2,129	2,066	2,094	1,945
Natural Gas	820	759	803	665	799
Nuclear	740	740	740	674	605
Nonhydroelectric Renewables	105	199	198	185	193
Wind	16	27	27	32	20
Biomass (Including Co-Firing)	45	82	82	105	102
Geothermal	18	59	57	19	42
Municipal Solid Waste and Landfill Gas	25	30	30	29	28
All Solar Sources	1	1	1	1	1
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.96	2.91	2.80	2.30	2.86
Electricity Price (1999 Cents per Kilowatthour)	6.4	6.4	6.7	6.4	6.4
Electricity Demand (Billion Kilowatthours)	3,794	3,787	3,747	3,627	3,581
Renewable Credit Price (1999 Cents per Kilowatthour)	0	4.9	3.2	NA	0.5
SO_2 Emissions (Million Tons)	10.38	10.39	8.55	10.60	NA
NO_x Emissions (Million Tons)	4.30	4.25	3.03	5.43	NA
Hg Emissions (Tons)	45.2	45.0	40.7	NA	NA
Carbon Emissions (Million Metric Tons)	644	625	598	626	589
2010 Projections					
Coal-Fired Capacity (Gigawatts)	327	316	281	308	270
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,297	2,157	1,268	2,101	1,852
Natural Gas	1,085	919	1,512	890	1,028
Nuclear	725	725	741	627	561
Nonhydroelectric Renewables	136	426	440	301	396
Wind	18	96	93	80	94
Biomass (Including Co-Firing)	56	190	211	151	208
Geothermal	31	104	99	35	57
Municipal Solid Waste and Landfill Gas	28	35	36	34	35
All Solar Sources	2	2	2	2	3
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.87	2.65	3.13	2.43	3.09
Electricity Price (1999 Cents per Kilowatthour)	6.1	6.3	8.6	6.3	6.3
Electricity Demand (Billion Kilowatthours)	4,147	4,117	3,830	3,883	3,856
Renewable Credit Price (1999 Cents per Kilowatthour)	0	4.5	3.0	NA	1.6
SO_2 Emissions (Million Tons)	9.70	9.70	3.60	9.70	NA
NO_x Emissions (Million Tons)	4.34	4.23	1.41	5.56	NA
Hg Emissions (Tons)	45.6	44.1	5.0	NA	NA
Carbon Emissions (Million Metric Tons)	693	639	441	646	582

[a]UCS gas price is in dollars per thousand Btu to electricity generators, not national average wellhead price.

NA = not available.

Sources: **EIA, Current Study:** National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_x.D070601A, and M2P7B08R_x.D070601A. **EIA, *AEO2000*:** National Energy Modeling System, run RPS2KFUL.D100699B. **UCS:** S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999).

technology costs and renewable resource availability. The Tellus study projected a negligible price increase over the reference level in 2010 for the 4-percent RPS target.

In each study, generation from nonhydroelectric renewables responded according to the RPS targets that were assumed. Both EIA's RPS 20% case and the UCS study projected well over 800 billion kilowatthours from eligible renewables by 2020. For 2010, EIA's RPS 20% case projected that generation from nonhydroelectric renewables would reach 426 billion kilowatthours in the RPS case, UCS projected 396 billion kilowatthours, and Tellus projected 144 billion kilowatthours. When joined with the emissions caps in EIA's integrated all CO_2 1990-7% case, generation from eligible renewables reaches 440 billion kilowatthours. All the studies showed significantly lower natural-gas-fired generation and smaller reductions in coal-fired generation. In EIA's RPS 20% case the decline was about 12 percent in 2010 for natural gas and about 8 percent in 2010 for coal. Similar declines were projected in the UCS and Tellus studies.[64] A slight decrease in demand was projected in both the RPS 20% case of the current EIA study and the EIA *AEO2000* analysis.

Of the eligible renewable sources, geothermal and biomass co-firing tend to be used first, and wind and dedicated biomass generation tend to be heavily exploited at higher RPS targets. In EIA's RPS 20% case, geothermal makes up 44 percent of the increase in 2005, but after all low-cost geothermal resources are taken, wind and biomass sources penetrate the market at a higher rate later in the forecast. Biomass co-firing is also important in the near term, making up 39 percent of the renewable increase in 2005 in EIA's RPS case. By 2010, the biomass contribution to generation is about twice as large as the wind contribution in both the EIA studies, and together they account for about 73 percent of the total increment in EIA's RPS case. Landfill methane is projected to fill a significant niche in all the analyses. Wind generation, however, clearly plays a critical role in all the studies. By 2010, wind accounts for 27 percent of the renewable increase in EIA's RPS 20% case and 24 percent of the increase in the UCS study. Despite different cost assumptions in the several models, all the studies indicate that even relatively modest renewable credit prices make wind technology competitive in favorable resource regions.

All the studies project that a national RPS would contribute to reductions of CO_2 emissions in the electricity generation sector. In the RPS 20% case, EIA projects a reduction of 54 million metric tons carbon equivalent (8 percent) from reference levels by 2010. The expected reduction is similar in the UCS analysis, 54 million metric tons carbon equivalent by 2010. EIA's AEO2000 analysis projected a reduction of 35 million metric tons carbon equivalent by 2010. The 4-percent RPS target modeled in the Tellus analysis yields a reduction of 9 million metric tons carbon equivalent, about 2 percent of reference case levels.

Renewable credit prices are comparable across the studies. EIA's 20-percent target (10 percent in 2010) results in a renewable credit price of 4.5 cents per kilowatthour in 2010 in the RPS case, after which the price declines. With the higher natural gas prices obtained in the integrated all CO_2 1990-7% case, the renewable credit price is reduced to 3.0 cents per kilowatthour in 2010. The UCS study projects a credit price of 1.6 cents per kilowatthour (1999 dollars) in 2010, but the longer forecast horizon (to 2030) results in a later peak of 2.7 cents per kilowatthour in 2024.[65] The 4-percent RPS target in the Tellus study yields a peak renewable credit price of 1.3 cents per kilowatthour (1999 dollars) in 2005, declining to 1.1 cents in 2010.

At the regional level, California-Southern Nevada and the Pacific Northwest are projected to become significant net suppliers of renewable credits to other regions in all the studies, and Texas and New England are also generally expected to be net suppliers in all the studies. With the higher RPS target in the UCS study and in the RPS 20% case of the current EIA study, MAPP (Upper Midwest) is projected to become the largest regional contributor to a national RPS target. At the lower target level in the Tellus study, wind resources in the MAPP region are not exploited, and the region is a net consumer of renewable credits.

[64]Bernow reports 48 billion kilowatthours of natural-gas-fired generation displaced and 4 billion kilowatthours of coal-fired generation displaced.

[65]The UCS methodology for calculating the credit price allowed renewable generators to see higher RPS targets in the future, so that while the target is increasing (as under the Jeffords proposal), more costs could potentially be recovered in the future, which tended to reduce the credit price in the near term. As the target is approached and / or met later in the forecast, the credit price and the shadow price tend to converge.

Mercury Emission Reduction Studies

EPA Analysis of Emissions Reduction Options for the Electric Power Industry

EPA's Clean Air Power Initiative (CAPI) produced a new series of modeling efforts in 1999.[66] The emissions analyzed were SO_2, NO_x, CO_2 and Hg. Slightly revising an earlier 1996 study,[67] NO_x emission reductions were not assumed beyond then-current statutory requirements, such as Phases I and II of the Title IV Acid Rain program or the NO_x SIP Call, under which 19 States and the District of Columbia must reduce NO_x emissions by 2004. Hypothetical emission caps were developed for each of the remaining emissions. The study allowed a variety of compliance options to meet the emission caps, including fuel switching, repowering, retrofitting or retiring units, and adjusting dispatch.

In modeling Hg emission reductions, EPA made assumptions about Hg concentrations in fuels and the control technologies plant operators might employ (Table 31).[68] Since the completion of EPA's report, further research has resulted in generally lower estimates of Hg concentrations by coal supply areas, accounting for some of the differences between the EPA and EIA assumptions shown in Table 31.[69] In its modeling, EIA also disaggregated by coal quality, allowing lower quality coals (gob and waste anthracite, not displayed in Table 31) to have much higher Hg concentrations than they would if combined in a weighted average with lower Hg coals. Still, EIA's estimates of Hg concentrations are lower in virtually all cases, reflecting the wide variability in Hg content among coal samples.[70] Concentrations of Hg in lignite from all regions are substantially less in EIA's estimate, and Hg concentrations in Powder River Basin subbituminous coal are also significantly different. Further differences are apparent in the important bituminous supply regions in Kentucky, West Virginia, and Pennsylvania.

There can be substantial variation in the Hg concentrations of coal from different coal seams within a State, and even within an individual coal mine. In some cases, the degree of variability reflects the uncertainty of using State-level values as a proxy for fuels consumed at

Table 31. Comparison of EPA and EIA Assumptions for Average Mercury Concentrations in Selected Coals
(Pounds per Trillion Btu)

State of Origin	Coal Rank	EPA Assumption	EIA Assumption
Alabama	B	11.91	8.16
Colorado	B	5.89	3.56
Illinois	B	7.18	5.84
Indiana	B	7.96	5.95
Kentucky	B	9.92	6.81
Louisiana	L	28.04	8.08
Maryland	B	26.58	15.55
Montana	B	8.38	NA
Montana	L	17.87	9.13
Montana	S	9.97	5.19
New Mexico	S	7.06	7.18
North Dakota	L	19.73	8.38
Ohio	B	14.94	15.72
Oklahoma	B	10.76	33.27
Pennsylvania	B	18.13	11.40
Texas	L	31.51	14.77
Utah	B	2.87	4.18
West Virginia	B	10.11	8.10
Wyoming	B	8.13	2.23
Wyoming	S	9.35	5.77

B = bituminous, L = lignite, S = subbituminous. NA = not available.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998). **EIA:** U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999).

[66]EPA's Clean Air Power Initiative (CAPI), which began in 1995, was intended to improve air pollution control efforts by involving the power generating industry in the development and analysis of alternative approaches to reducing three major emissions: SO_2, NO_x, and, potentially, Hg. The analysis used the Integrated Planning Model (IPM), a detailed model of the electric power industry in which plant operators react to alternative levels of pollution targets. CAPI proposed a "cap and trade" approach for the emissions and modeled the proposed reductions on a national scale. Initial NO_x caps were set for both summer and winter beginning in 2000, and the initial rate-based caps were then reduced to a fairly stringent absolute cap of 0.15 pounds per million Btu in 2005. At the same time, SO_2 was reduced in 2010 by lowering the Clean Air Act Amendments of 1990 Title IV SO_2 allowance cap by 50 percent, to about 4.5 million tons per year. A cap on Hg emissions was set in 2000 to the amount expected in 2000, then lowered in 2005 by 50 percent, and again in 2010 by another 50 percent (total 75-percent reduction). The results of the initial analysis were published in 1996.

[67]U.S. Environmental Protection Agency, *EPA's Clean Air Power Initiative* (Washington, DC, 1996).

[68]EPA based the mercury concentrations on U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998).

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

[70]In 1999, EPA also estimated total Hg emissions at around 50 tons. Both EIA and EPA now estimate these emissions at around 43 tons.

coal-fired generating stations.[71] Further, EPA assumed a 21-percent reduction in Hg concentration from coal cleaning for bituminous coals shipped from 14 States, an adjustment not reflected in Table 31. The Hg concentrations used for EIA's analysis represented measurements taken at electric power plants, after preparation.[72] EPA and EIA used similar estimates for the negligible Hg concentrations in both oil and natural gas.

Another key difference between the EIA and EPA studies lies in the emissions modification factors (EMFs) corresponding to specific plant configurations (Table 32). After the Hg content of the fuel is estimated, Hg reductions in both models are calculated by applying assumed levels of reductions for specific items of control equipment. Plants may be configured with one or more control technologies, each assumed to reduce Hg in the flue gas by a certain percentage. The EMFs are nearly identical for particulate removal equipment. With regard to scrubbers, EPA modeled a generic scrubber with an EMF of 66 percent, whereas EIA used technology-specific EMFs for scrubbers ranging from 34 percent to 81 percent.[73] EPA and EIA also differed on the removal rate for fabric filters (also called baghouses), with EPA assuming an EMF of 56 percent and EIA 31 percent. EPA also assumed a variety of EMFs based on the boiler type present at the generating station, ranging from 41 percent to 100 percent. EIA, however, used a generic EMF of 93 percent, representing reductions in the combustion process from either the boiler-type or any NO_x controls.

Like the present EIA analysis, the EPA analysis concluded that the only viable control technology for directly reducing Hg emissions alone was activated carbon injection (ACI).[74] However, combining ACI technology with equipment designed to mitigate other emissions further reduces Hg, so that, effectively, plant operators have several compliance alternatives. EPA began with a simplified plant configuration menu of eight existing configurations,[75] each of which could fire either bituminous or subbituminous coal (16 model plant types), and then allowed the plants to deploy ACI in combination with spray coolers and / or fabric filters. Implied reduction rates for these mitigation options ranged from 65 percent Hg removal (cold side electrostatic precipitator using subbituminous coal with spray cooler and ACI) to 90 percent Hg removal (several combinations that include wet scrubbers).[76] EPA further assumed that higher reduction targets would require disproportionately greater amounts of activated carbon, reaching a peak ratio of 15,000 grams carbon to each gram Hg for the configuration of electrostatic precipitator with bituminous coal.

EPA's estimates of the costs for these technologies are compared with EIA's estimates for similar plant configurations in Table 33. Both EIA and EPA report high capital costs associated with the installation of fabric filters, and EIA's estimates of capital costs associated with spray coolers and fabric filters are slightly higher than EPA's. These capital costs, however, are generally less significant than the variable costs associated with activated carbon, so that the most important difference in the cost parameters lies in the assumptions regarding the efficiency of each model configuration. Whereas EPA fixed the rate of Hg reduction, EIA assumed that the rate of reduction would vary with the amount of carbon injected into the flue gas stream. Because EPA fixed

Table 32. Comparison of EPA and EIA Assumptions for Emission Modification Factors by Type of Emission Control Equipment
(Percentage of Hg Emissions Removed)

Emission Control Device	EPA Assumption	EIA Assumption
Flue Gas Desulfurization Scrubbers	66	NA
Wet Scrubber (Bituminous Coal)	NA	34
Wet Scrubber (Other Coals)	NA	81
Dry Scrubber	NA	61
Fabric Filter	56	31
Cold Side Electrostatic Precipitator	68	69
Hot Side Electrostatic Precipitator	100	100
Particulate Matter Scrubber	96	96

NA = not available.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998). **EIA:** U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999), and National Energy Technology Laboratory.

[71]T. D. Brown, D. N. Smith, R. A. Hargis, Jr., and W. J. O'Dowd, "Mercury Measurement and Its Control: What We Know, Have Learned, and Need To Further Investigate," *Journal of the Air & Waste Management Association* (June 1999).

[72]There is much uncertainty about Hg reductions from coal preparation. A recent estimate has put the Hg reduction at nearly 60 percent. Rae-Hoan Yoon, "Developing Advanced Separation Technologies for Producing Clean Coal," testimony before the Subcommittee on Energy and Air Quality, U.S. House of Representatives (March 14, 2001).

[73]EMF rates refer to the amount of Hg remaining in the effluent gas.

[74]While recognizing that coal cleaning procedures could have some promise for lowering Hg emissions, neither EPA nor EIA modeled this alternative, due to a lack of information on the incremental costs of preparation to remove Hg.

[75]Both EIA and EPA estimated that about two-thirds of coal-fired capacity would add cold side electrostatic precipitators.

[76]U.S. Environmental Protection Agency, Office of Air and Radiation, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), Appendix C.

the rate of reduction, the analysis also fixed the ratio of activated carbon to Hg, yielding a linear cost curve for variable carbon costs. The last two columns of Table 33 compare EIA's estimate of variable carbon cost *at the reduction rate specified by EPA*; some of the costs are significantly different. As both analyses acknowledge, however, the rate of carbon injection must increase rapidly as higher Hg removal rates are pursued. At a reduction rate of 90 percent, EIA's variable costs for carbon, increasing exponentially rather than linearly, far outstrip those assumed by EPA.[77]

EPA employed two alternative cases to analyze potential Hg reductions, the first based on Maximum Achievable Control Technology (MACT) and the second using a market-based national cap and trade approach. The MACT option would apply to generators larger than 25 megawatts and take effect in 2007. Assumed technology options are ACI with spray cooling and / or fabric filters in certain instances. The cap and trade approach assumed the level of Hg reduction achieved by the MACT from 2007 to 2025 as the cap, and coal-fired generators could trade any Hg allowances received in that year with other generators in the contiguous United States.[78] No banking was allowed. Each of these approaches was modeled with an Hg reduction only, and with two other multiple emission reduction cases: a 50-percent SO_2 reduction by 2010, and a 50-percent SO_2 reduction with an additional CO_2 reduction to 515 million metric tons carbon equivalent in 2008. Cost impacts to the electric power industry were mitigated under the cap and trade model, reducing total resource costs by 23 percent in the fully integrated cap and trade case as compared with the MACT cases. Because it most closely resembles the present EIA analysis, EPA's cap and trade approach is compared below.

The EPA reported that annual incremental costs to the industry under the most stringent integrated scenario would be $6.3 billion (1999 dollars) in 2010. The incremental costs for reducing Hg alone were reported as $2.3 billion under a MACT standard and $2.1 billion under a cap and trade regime. EPA also found that, generally, the cap and trade approach reduced total incremental costs to the power generation industry (as compared with the MACT approach), but the savings were modest because the assumed technology costs for Hg removal did not exhibit significant economies of scale.[79] The greatest cost saving occurred in the integrated carbon reduction case, in which the use of cap and trade instead of MACT was projected to achieve a 23-percent cost reduction. Reduced electricity demand in this case mitigated the impact of the 50-percent SO_2 cap in the fuel selection process, allowing generators to select coal with lower Hg content and possibly higher SO_2 content. Thus, SO_2 reductions in 2010 were greater under the MACT scenario than under the cap and trade scenario. Emissions of NO_x, CO_2, and Hg were similar under the two regimes.

Comparisons of Mercury Reduction Results

Seven alternative policy cases are offered for comparison. The first is a national cap and trade case, where EPA caps national Hg emissions at 35 percent of the baseline projection in 2010, or about 17 tons, and EIA's Hg sensitivity case caps Hg emissions at 60 percent below estimated 1997 levels, or about 20 tons. Two multiple

Table 33. Comparison of EPA and EIA Assumptions for Costs of Mercury Emission Control Equipment by Selected Plant Configurations and Percentage of Hg Emissions Removed

Existing Configuration and Coal Rank	Controls Added	Percent Hg Removed	Capital Costs (1999 Dollars per Kilowatt)		Total Operating and Maintenace Costs, Excluding Activated Carbon (1999 Mills per Kilowatthour)		Variable Costs for Activated Carbon (1999 Mills per Kilowatthour)	
			EPA	EIA	EPA	EIA	EPA	EIA
Cold Side ESP, SUB . . .	SC and ACI[a]	65	8.24	NA	0.30	NA	0.31	NA
Cold Side ESP, SUB . . .	SC, ACI, and FF	65	NA	45.23	NA	0.29	NA	0.07
Hot Side ESP, BIT	SC, ACI, and FF	85	45.57	53.37	0.91	0.81	0.41	0.71
Hot Side ESP, SUB	SC, ACI, and FF	85	44.92	45.23	0.86	0.75	0.24	0.11
DS and ESP, BIT	Simple injection system	85	1.62	3.24	0.14	0.15	0.41	3.54
DS and ESP, SUB	Simple injection system	85	0.97	2.42	0.09	0.14	0.24	0.69

[a]EIA did not model a plant configuration of spray cooler with simple injection.

ACI = activated carbon injection, BIT = bituminous, DS = dry scrubber, ESP = electrostatic precipitator, FF = fabric filter, SC = spray cooler, SUB = subbituminous. NA = not applicable.

Notes: EPA's rates of reduction are fixed; EIA's variable costs are reported at the fixed level specified.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air and Radiation, *Analysis of Emissions Reductions Options for the Electric Power Industry* (Washington, DC, March 1999), web site www.epa.gov/capi/multipol/mercury.htm. **EIA:** Unpublished data from the National Energy Technology Laboratory (NETL).

[77]The EPA and EIA studies assume the same cost for activated carbon, $1.00 per kilogram (1997 dollars).

[78]Therefore, EPA did not model a "hard cap" in either scenario. Reductions are compared with projected baseline emissions absent any policy change.

[79]Costs are annual incremental costs directly attributable to Hg control through retrofits and, to a lesser extent, altered fuel consumption.

emission reduction cases are compared, one with carbon emissions capped and one without. The targets for NO_x, SO_2, and CO_2 in the EIA analysis are significantly more stringent than those modeled by EPA.[80] In its integrated carbon case, EPA also assumed higher demand efficiencies, reducing electricity demand.[81] Finally, two MACT scenarios are compared. EPA's MACT scenario resulted in Hg reductions of 65 percent from projected baseline levels, while EIA's MACT 90% case projected Hg emissions reductions of 85 percent from 1997 levels.

Total coal supply is reduced under all Hg reduction scenarios (Table 34). Both EIA and EPA forecast only a modest drop in total coal production under a moderate Hg cap. Both models forecast an accelerated decline in coal production as SO_2 reductions are introduced, and both project substantial declines when CO_2 emissions become the policy goal. EIA's projection for electricity generation is significantly higher than that reported by the EPA because of greater coal capacity in 2010—about 30 gigawatts—as well as higher capacity factors and higher electricity demand. Because of different assumptions regarding Hg concentrations in Eastern coal, EPA and EIA forecast slightly different dynamics between the three Appalachian supply regions. In the EPA analysis, the Northern Appalachia supply region retains its production share and even increases its share under multiple emission reduction cases. EIA, in contrast, forecasts reduced production of Northern Appalachian coal in every policy case except under the 90% MACT reduction scenario. Conversely, EIA projects a modest increase in coals produced in Central and Southern Appalachia when Hg is targeted with SO_2, but EPA forecasts a declining role for these coals under all reduction scenarios except the MACT. The Midwest supply region obtains a larger market share in both the EIA and EPA forecasts in all but one policy case (integrated NO_x, SO_2, CO_2 1990-7%, Hg), to the extent that Midwest production increases from baseline levels. Because coal production declines generally when Hg is targeted, the supply of Western coal declines in all cases, but its market share holds fairly steady, in the 50 percent range, across all the scenarios. Higher sulfur Eastern coals also become slightly more competitive as Hg control equipment is added, especially in the MACT cases.

Because of the introduction of Hg control equipment, coal-fired capacity stays about the same across all the Hg reduction cases (Table 35); however, coal capacity loses some of its share when CO_2 reductions are introduced (integrated NO_x, SO_2, CO_2 1990-7%, Hg). In the cap and trade Hg reduction cases, EIA's 60-percent sensitivity case prompts 72 gigawatts of Hg retrofits (fabric filters and spray coolers) by 2010. In contrast, EPA's 65-percent reduction brings on 271 gigawatts of Hg retrofits in the same year. This different response highlights the role of variable levels of activated carbon usage in EIA's NEMS model, as compared with the constant levels of carbon injection employed in EPA's IPM. EIA also achieves a much larger share of the Hg reduction by deploying scrubbers, retrofitting 43 gigawatts by 2010, while EPA retrofits only 8 gigawatts. Interestingly, both EIA and EPA report modest declines in NO_x retrofits when Hg is the sole emission targeted. When CO_2 is

Table 34. Comparison of EPA and EIA Projections for Coal Supply by Region and Mercury Emissions Reduction Scenario, 2010
(Million Short Tons)

Coal Supply Region	EIA: Reference	EIA: Hg 20-Ton (60% Hg Reduction by 2008)	EIA: Integrated NO_X, SO_2, CO_2 1990-7%, Hg (90% Hg Reduction by 2008)	EIA: Hg MACT 90%	EPA: Reference	EPA: 65% Hg Reduction, Cap and Trade	EPA: 65% Hg Cap and 50% SO_2 by 2010	EPA: 65% Hg Cap, 50% SO_2, 515 Carbon with High Efficiency	EPA: 65% MACT
Northern Appalachia	165	158	82	170	109	105	130	113	111
Central and Southern Appalachia	255	264	163	248	213	203	156	143	216
Midwest	136	172	106	150	109	131	162	149	127
West	694	621	317	669	540	504	470	357	499
Central West and Gulf[a]	44	24	6	46	63	50	47	14	58
Total	**1,295**	**1,239**	**674**	**1,282**	**1,034**	**992**	**964**	**776**	**1,011**

[a]Central West and Gulf corresponds to the Western Interior and Gulf supply regions in EIA's NEMS Coal Market Module.

Sources: **EIA:** National Energy Modeling System runs M2BASE.D060801A, M2M6008.D060801A, M2P7B08.D060801A, and M2M9008M.D060801A. **EPA:** 1999 Integrated Planning Model runs HgIPM9c, Hgtrading1d, Hgtrading2d, Hgtrading3d, and HgMact1d.

[80]EIA's integrated case includes a 75-percent NO_x reduction below 1997 levels, whereas EPA assumes NO_x reductions only to levels stipulated by the NO_x SIP call. EIA's SO_2 target is 75 percent below 1997 levels, whereas EPA's target is 50 percent reduction, to 4.8 million tons. EIA's CO_2 target is 7 percent below 1990 levels (about 440 million metric tons carbon equivalent), whereas EPA's CO_2 target is 515 million metric tons carbon equivalent. EIA's caps are based on assumptions provided by the House Government Reform Committee, Subcommittee on National Economic Growth, Natural Resources and Regulatory Affairs in its request for this study. See Appendix for full text of letter.

[81]Demand was assumed to be reduced by 1.5 percent annually, reaching a total reduction of 15 percent in 2010.

included in the integrated cases, fewer retrofits of all types are projected by both NEMS and IPM; however, similar levels of scrubber retrofits are necessary in both models to achieve the SO_2 targets. When MACT is chosen as the control regime, both EIA and EPA project that retrofits with activated carbon systems on virtually all coal-fired generating capacity will reduce the amount of scrubber retrofits needed to achieve the Hg targets.

Retrofitted with appropriate control technology, coal-fired generation is able to retain most of its market share in both the EIA and the EPA forecasts, although significantly, EIA generally projects more coal-fired capacity, including some new builds, and more coal-fired generation, factors which increase both the difficulty and the costs of meeting the targets. When Hg emissions alone are constrained, generation from coal is reduced only

Table 35. Comparison of Key Mercury Emission Reduction Results

Item	EIA				EPA				
	Reference	Hg 20-Ton (60% Hg Reduction by 2008)	Integrated NO_X, SO_2, CO_2 1990-7%, Hg (90% Hg Reduction by 2008)	Hg MACT 90%	Reference	65% Hg Reduction, Cap and Trade	65% Hg Cap and 50% SO_2 by 2010	65% Hg Cap, 50% SO_2, 515 Carbon with High Efficiency	65% MACT
2007 Projections									
Coal-Fired Capacity (Gigawatts)	319	317	303	317	303	304	303	302	305
NO_x Retrofits (Gigawatts)	118	118	150	118	199	192	191	189	192
SO_2 Retrofits (Gigawatts)	7	10	10	8	4	8	79	51	5
Hg Retrofits (Gigawatts)	0	0	0	0	0	270	245	250	303
Electricity Generation by Fuel (Billion Kilowatthours)									
Coal	2,220	2,207	1,653	2,212	2,091	2,080	2,043	2,011	2,085
Natural Gas	916	927	1,211	921	626	637	673	565	631
Nuclear	738	738	742	738	613	613	613	613	613
Nonhydroelectric Renewables	119	119	228	120	61	61	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.88	2.88	2.98	2.88	NA	NA	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.74	14.86	14.03	14.74	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.2	6.3	7.7	6.2	NA	NA	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	3,936	3,935	3,765	3,936	3,690	3,690	3,690	3,550	3,690
SO_2 Emissions (Million Tons)	10.1	10.1	6.4	10.1	10.9	10.5	5.4	6.5	10.5
NO_x Emissions (Million Tons)	4.30	3.44	2.04	3.43	4.25	4.25	4.20	4.09	4.25
Hg Emissions (Tons)	45.3	45.1	31.1	45.2	52.0	18.0	16.0	16.3	18.0
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	662	661	516	662	615	613	609	587	614
CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	0	0	82	0	NA	NA	NA	NA	NA
SO_2 Allowance Price (1999 Dollars per Ton)	182	180	179	185	NA	NA	NA	NA	NA
2010 Projections									
Coal-Fired Capacity (Gigawatts)	327	323	277	324	303	304	301	284	304
NO_x Retrofits (Gigawatts)	119	118	177	119	209	192	190	181	193
SO_2 Retrofits (Gigawatts)	7	43	21	27	6	8	87	50	8
Hg Retrofits (Gigawatts)	0	72	105	356	0	271	251	249	302
Electricity Generation by Fuel (Billion Kilowatthours)									
Coal	2,297	2,237	1,113	2,266	2,114	2,073	2,006	1,681	2,099
Natural Gas	1,085	1,133	1,889	1,115	759	799	866	949	774
Nuclear	725	725	741	725	580	580	580	580	580
Nonhydroelectric Renewables	136	133	236	131	61	61	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.87	2.90	3.66	2.89	NA	NA	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.08	15.09	14.38	14.25	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.1	6.2	8.4	6.2	NA	NA	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	4,147	4,132	3,851	4,140	3,809	3,809	3,809	3,568	3,809
SO_2 Emissions (Million Tons)	9.7	9.7	3.2	9.7	9.7	9.8	4.8	4.8	9.7
NO_x Emissions (Million Tons)	4.34	3.42	1.26	3.44	4.15	4.07	3.94	3.21	4.12
Hg Emissions (Tons)	45.6	20.0	5.0	8.0	50.9	17.5	15.1	12.8	17.6
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	693	684	434	690	621	612	603	518	617
CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	0	0	120	0	NA	NA	NA	NA	NA
SO_2 Allowance Price (1999 Dollars per Ton)	187	0	0	114	NA	NA	NA	NA	NA
Incremental Costs (Billion 1999 Dollars)	0.0	1.7	23.2	5.9	0.0	2.1	5.2	6.3	2.3

NA = not available.

Note: Because Hg retrofits can include both fabric filters and spray coolers, retrofitted capacity may exceed total coal-fired capacity.

Sources: **EIA:** National Energy Modeling System runs M2BASE.D060801A, M2M6008.D060801A, M2P7B08.D060801A, and M2M9008M.D060801A. **EPA:** 1999 Integrated Planning Model runs HgIPM9c, Hgtrading1d, Hgtrading2d, Hgtrading3d, and HgMact1d.

negligibly by 2010. Further, in both the EIA and EPA MACT cases, coal-fired generation remains very close to reference levels. When SO_2 emissions targets are introduced, the IPM forecasts another slight reduction by 2010; in EIA's integrated NO_x, SO_2, CO_2 1990-7%, Hg case, however, the additional 75-percent NO_x reduction target forces a larger decrease in coal-fired generation by 2010. Both models reduce coal-fired generation significantly under carbon reduction regimes, although some of the decline in EPA's scenario can be traced to reduced demand under the high efficiency assumptions. Generally, increased gas-fired generation replaces the coal generation; however, both nuclear (in the form of reduced retirements) and nonhydroelectric renewables also make a contribution in EIA's cases, and by 2010 electricity demand falls as more emissions are targeted and retail electricity prices rise.

The patterns of emission reductions are similar in the EIA and EPA studies. Carbon emissions fall slightly from reference levels in the non-carbon cases, reflecting the decrease in coal-fired generation under Hg control policies. Substantial reductions in carbon emissions, however, require an explicit cap. Hg emissions in EIA's cap and trade cases reflect the hard-target caps, while in EPA's cases, Hg emissions continue to fall from the 65-percent reduction level as other emissions are targeted and more control equipment is added. The pattern of reductions, however, reveals that both models suggest a similar conclusion: marginal Hg reductions over a range from 65 to 80 percent come somewhat easily, but raising the target to 90 percent (or 5 tons Hg annually) increases the difficulty, and associated costs, exponentially. Both models suggest that NO_x emissions fall only slightly in the absence of explicit NO_x reduction targets. SO_2 emissions vary directly with the amount of scrubber retrofits, but when carbon is targeted, the shift to gas-fired generation leads to SO_2 reductions with fewer retrofits.

Both studies indicate that costs to the industry, either annual incremental costs in the EPA study or total resource costs in the EIA study, are mitigated by a cap and trade approach, but the savings under the cap and trade approach are not as dramatic as for other emissions, such as SO_2. In both models, there is only one control option (ACI), and assumptions used in both models provide for high removal rates. EPA assumed limited economies of scale, and EIA assumed none for ACI equipment. Therefore, opportunities for the industry to maximize Hg reductions at larger plants while purchasing allowances for smaller plants are relatively few. In the EPA study, the integrated cap and trade scenario does provide some benefits not available under the MACT. With significant scrubber retrofits and reduced demand, about one-tenth of the generators were able to address Hg reductions by switching to coals higher in sulfur but lower in Hg content, thereby avoiding installation of MACT controls—an alternative generally not available at the higher target levels modeled by EIA. The projected costs of compliance in EIA's analysis are higher than those found by EPA, because EIA projects higher electricity demand, more use of coal-fired generation, and more use of natural gas, especially in the CO_2 cap cases. In EIA's Hg 20-ton case, resource costs are projected to be $1.7 billion higher than in the reference case, compared to a difference of $2.1 billion in EPA's Hg cap and trade case.

One of the biggest potential concerns under an Hg cap and trade system is uneven regional distribution of emissions.[82] Allaying these fears somewhat, both EIA and EPA found that the regulatory regime, either cap and trade or MACT, did not introduce any significant differential impacts in regional emissions of Hg. Because they have most of the baseload coal capacity, the Southeast (SERC) and the Midwest (ECAR) regions are the largest contributors to Hg emissions. Under both control regimes, these two regions reduce their Hg emissions from reference levels by large amounts in both absolute and percentage terms. Both EIA and EPA forecast significant emission reductions in percentage terms for Texas (ERCOT). Because California and Florida have very little coal capacity, both EIA and EPA forecast slight increases in shares of national Hg emissions for those areas. The Mid-American Interconnected Network (MAIN, consisting of Illinois and Wisconsin) and the Middle Atlantic (MAAC) region exhibit different responses in the two models. EIA forecasts a slight increase in the share of emissions from MAIN, whereas EPA projects a significant decline. For MAAC, EIA forecasts a slight decline by 2010 and EPA a slight increase. The differences are likely attributable to slight regional shifts in the level of Hg emissions targeted.

Conclusions

The studies reviewed here share a number of similar conclusions. Under an RPS, biomass and wind generators provide most of the required renewable generation. Geothermal sources make an important contribution in the near term. At lower RPS target levels, wind turbines may be developed without much effect on the marginal cost of electricity in several regions. Natural gas prices play a critical role in analyzing the cost of achieving the RPS: where natural gas prices are low, the cost of replacing natural-gas-fired generation with any of these renewable sources is relatively high.

[82] "Any regulatory scheme for mercury that incorporates trading or other approaches that involve economic incentives must be constructed in a way that assures that communities near the sources of emissions are adequately protected." U.S. Environmental Protection Agency, *Federal Register*, Vol. 65, No. 245 (December 20, 2000).

With regard to Hg reductions, both EIA and EPA find that costs accelerate as reduction targets become more stringent. Imposing Hg reductions only has little effect on reducing other emissions. Reducing CO_2 and Hg emissions jointly leads to slightly greater Hg reductions. Incremental costs, however, rise rapidly when CO_2 is targeted along with other emissions. Controlling Hg emissions through a MACT rather than a cap and trade program does not affect regional distributions of emissions. The MACT approach, however, produces a smaller reduction in Hg emissions than the cap and trade approach and probably increases SO_2 emissions.

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Appendix A

Letters from the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs

ONE HUNDRED SIXTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON GOVERNMENT REFORM

2157 RAYBURN HOUSE OFFICE BUILDING

WASHINGTON, DC 20515–6143

MAJORITY (202) 225-5074
MINORITY (202) 225-5051
TTY (202) 225-6852

June 29, 2000

<u>BY FACSIMILE</u>

The Honorable Larry Pettis
Acting Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Pettis:

I am writing to request that the Energy Information Administration (EIA) analyze the potential costs of various "multi-pollutant" strategies to reduce air emissions from electric power plants.

Many "stakeholders" in the debates over New Source Review reform and Clean Air Act reauthorization advocate "integrated, market-based, multi-pollutant" strategies to reduce air emissions from electric power generation. Utilities and environmental activists alike argue that the current approach, which imposes numerous, uncoordinated, pollutant-by-pollutant requirements, is costly, rife with litigation, and fraught with compliance delays. Utilities in particular complain that the resulting lack of "regulatory certainty" discourages long-term planning, investment, and innovation, shortchanging both consumers and the environment. Proponents of multi-pollutant strategies typically advocate emission caps for nitrogen oxides (NOx), sulfur dioxide (SO_2), mercury, and carbon dioxide (CO_2), with emissions banking, trading, and credit for early reductions to provide flexibility and lower costs.

I have two concerns about the proposed multi-pollutant strategies. First, flexibility is purchased at the price of extending the Environmental Protection Agency's (EPA's) regulatory web to encompass CO_2. I believe this would set a dangerous precedent, because CO_2 is the most ubiquitous byproduct of industrial society. The power to control CO_2 emissions is potentially the power to eliminate coal as a fuel source, restructure the electric power industry by political fiat, and regulate vast numbers of small- and mid-sized users of fossil fuels.

Second, the proposed emission reductions are very steep. Under one such proposal, for example, electric utilities would be required to reduce NOx and SO_2 emissions 75 percent below

1997 levels, reduce mercury emissions 90 percent below 1997 levels, and reduce CO_2 emissions to 1990 levels -- all by 2005. Another proposal would require comparable reductions and, in addition, phase in a 10 percent renewable energy portfolio standard (RPS) by 2010 and a 20 percent RPS by 2020. By way of comparison, the Clinton-Gore Administration's "Comprehensive Electricity Competition Act" (CECA) would phase in a 7.5 percent RPS by 2010. In short, multi-pollutant strategies may prove to be quite costly, notwithstanding their utilization of emissions trading.

Therefore, pursuant to the Constitution and Rules X and XI of the United States House of Representatives, I request that EIA analyze the cost implications -- the likely impacts on both consumers and energy markets -- of the following multi-pollutant emission control scenarios for power plants. Please provide results through 2020, in periods of five years or less, using EIA's latest Annual Energy Outlook as the baseline.

Scenario 1a: Assume a starting date of 2001. By 2005, reduce NOx and SO_2 emissions 75 percent below 1997 levels, reduce mercury emissions 90 percent below 1997 levels, and reduce CO_2 emissions to 1990 levels.

Scenario 1b: In addition to Scenario 1a, phase in a 5 percent RPS by 2005, a 10 percent RPS by 2010, and a 20 percent RPS by 2020.

Scenario 1c: In addition to Scenario 1a, reduce CO_2 emissions 7 percent below 1990 levels by 2008-2012.

Scenario 1d: In addition to Scenario 1b, reduce CO_2 emissions 7 percent below 1990 levels by 2008-2012.

Scenario 2a: Assume a starting date of 2001. By 2008, reduce NOx and SO_2 emissions 75 percent below 1997 levels, reduce mercury emissions 90 percent below 1997 levels, and reduce CO_2 emissions to 1990 levels.

Scenario 2b: In addition to Scenario 2a, phase in a 5 percent RPS by 2005, a 10 percent RPS by 2010, and a 20 percent RPS by 2020.

Scenario 2c: In addition to Scenario 2a, reduce CO_2 emissions 7 percent below 1990 levels by 2008-2012.

Scenario 2d: In addition to Scenario 2b, reduce CO_2 emissions 7 percent below 1990 levels by 2008-2012.

For Scenarios 1d and 2d, please estimate the individual impacts of each provision as well as the combined impacts of all provisions. For example, to what extent would meeting the CO_2 targets achieve the other requirements, including the RPS? I am aware that the mercury provisions will be difficult to analyze due to limitations in the available data. However, if EIA is unable to model the mercury provisions directly, perhaps EIA would be able to infer the costs of mercury reductions from the projected impacts of other provisions on mercury emissions.

Please deliver your analysis to the Subcommittee majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building by October 1, 2000. If EIA is unable to analyze the costs of the mercury provisions by October 1st, then please prepare a follow-up paper analyzing those costs -- both individually and in combination with the other proposed emission control requirements -- as soon as possible after October 1st.

If your have any questions about this request, please call Subcommittee Staff Director Marlo Lewis at 225-1962. Thank you for your attention to this request.

Sincerely,

David M. McIntosh
Chairman
Subcommittee on National Economic Growth
Natural Resources, and Regulatory Affairs

cc: The Honorable Dan Burton
The Honorable Dennis Kucinich

3

ONE HUNDRED SIXTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON GOVERNMENT REFORM

2157 RAYBURN HOUSE OFFICE BUILDING

WASHINGTON, DC 20515-6143

MAJORITY (202) 225-5074
MINORITY (202) 225-5051
TTY (202) 225-6852

August 17, 2000

<u>BY FACSIMILE</u>

The Honorable Larry Pettis
Acting Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Pettis:

This letter is in the nature of a clarification. On June 29, 2000, Subcommittee Chairman David McIntosh requested that the Energy Information Administration (EIA) analyze the potential costs of various "multi-pollutant" strategies to reduce air emissions from electric power plants. All modeling exercises depend upon assumptions. In its analysis, EIA may find that "multi-pollutant" strategies, especially emission controls for carbon dioxide (CO_2), are so expensive as to encourage new investment in nuclear power. If so, EIA will need to make one of two assumptions: Either (1) the nuclear option is limited to life extension of existing nuclear units, or (2) it also includes construction of new units.

EIA should use assumption (1). Although the proposed "multi-pollutant" strategies may be costly enough to make construction of new nuclear capacity attractive from a strictly economic point of view, public opinion and other political factors are likely to preclude such construction in the foreseeable future. For example, utilities will be disinclined to invest in new nuclear units as long as substantial numbers of policymakers and citizens oppose the transport and remote disposal of spent nuclear fuel.

In addition, some of the leading advocates of CO_2 emission reductions are staunch opponents of nuclear power. For example, in *Earth in the Balance*, Vice President Al Gore, citing safety concerns regarding both reactors and nuclear waste, asserts: "It is a mistake, therefore, to argue that nuclear power holds the key to solving global warming." In Mr. Gore's view, "the present generation of nuclear technology ... seems now rather obviously at a technological dead end," and, consequently, "the proportion of world energy use that could practically be derived from nuclear power is fairly small and is likely to remain so" (p. 328).

Presumably, most supporters of "multi-pollutant" strategies within the environmental community are of the same mind.

In summary, EIA should assume that the nuclear option will be limited to life extension of existing nuclear plants, if they are economically viable. If you have any questions about this letter, please contact me at 225-1962.

Sincerely,

Mario Lewis, Jr.
Staff Director
Subcommittee on National Economic Growth,
Natural Resources, and Regulatory Affairs

cc: Mr. Kevin Binger
Mr. Phil Schiliro

2

Appendix B

Tables for NO_x and SO_2 Cap Cases

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.01	11.98	11.27	11.22	11.27	11.12	11.11	11.14
Natural Gas Plant Liquids	2.62	3.12	3.12	3.10	3.37	3.38	3.38	4.16	4.17	4.18
Dry Natural Gas	19.16	21.95	21.94	21.83	24.04	24.13	24.14	30.24	30.30	30.39
Coal	23.08	25.45	25.26	25.45	26.55	26.29	26.21	27.16	26.93	27.06
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.59	6.54
Renewable Energy[1]	6.53	7.13	7.13	7.18	7.90	7.91	8.04	8.42	8.44	8.55
Other[2]	1.65	0.35	0.35	0.35	0.31	0.30	0.54	0.33	0.32	0.33
Total	**73.29**	**77.88**	**77.72**	**77.80**	**81.19**	**80.97**	**81.33**	**87.97**	**87.85**	**88.18**
Imports										
Crude Oil[3]	18.96	21.42	21.42	21.43	22.38	22.45	22.39	25.82	25.88	25.82
Petroleum Products[4]	4.14	6.28	6.22	6.21	8.65	8.61	8.38	10.80	10.73	10.68
Natural Gas	3.63	5.13	5.13	5.12	5.55	5.56	5.61	6.59	6.59	6.63
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**	**33.93**	**33.88**	**33.87**	**37.54**	**37.58**	**37.35**	**44.18**	**44.16**	**44.09**
Exports										
Petroleum[6]	1.98	1.73	1.74	1.74	1.69	1.69	1.73	1.85	1.83	1.86
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	1.51	1.45	1.46	1.45	1.41	1.41	1.38
Total	**3.62**	**3.57**	**3.57**	**3.57**	**3.58**	**3.58**	**3.61**	**3.89**	**3.87**	**3.88**
Discrepancy[7]	**0.69**	**0.43**	**0.42**	**0.42**	**0.04**	**0.04**	**0.13**	**0.11**	**0.14**	**0.15**
Consumption										
Petroleum Products[8]	38.02	41.34	41.31	41.27	44.44	44.42	44.28	50.45	50.44	50.37
Natural Gas	22.21	26.44	26.43	26.31	29.00	29.10	29.15	36.06	36.09	36.23
Coal	21.42	24.39	24.21	24.40	25.64	25.38	25.34	26.42	26.18	26.31
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.59	6.54
Renewable Energy[1]	6.54	7.13	7.14	7.19	7.91	7.91	8.05	8.43	8.45	8.55
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**	**107.81**	**107.61**	**107.68**	**115.11**	**114.94**	**114.94**	**128.16**	**128.00**	**128.25**
Net Imports - Petroleum	**21.12**	**25.96**	**25.90**	**25.90**	**29.34**	**29.37**	**29.05**	**34.78**	**34.78**	**34.65**
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	2.96	2.95	2.95	2.87	2.88	2.86	3.22	3.20	3.22
Coal Minemouth Price (dollars per ton)	17.17	15.05	15.06	15.49	14.08	14.18	14.81	12.87	13.02	13.00
Average Electric Price (cents per Kwh)	6.6	6.4	6.5	6.3	6.1	6.2	6.2	6.2	6.2	6.2

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur 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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Sector and Source	1999	2005 Reference	2005 NO_x 2008	2005 SO_2 2008	2010 Reference	2010 NO_x 2008	2010 SO_2 2008	2020 Reference	2020 NO_x 2008	2020 SO_2 2008
		Projections								
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.40	0.40
Petroleum Subtotal	1.42	1.40	1.41	1.40	1.30	1.30	1.30	1.23	1.23	1.23
Natural Gas	4.88	5.57	5.58	5.57	5.61	5.61	5.61	6.23	6.24	6.24
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	0.44	0.44	0.44
Electricity	3.91	4.57	4.54	4.57	4.95	4.94	4.93	5.79	5.78	5.79
Delivered Energy	**10.66**	**12.01**	**11.99**	**12.02**	**12.34**	**12.32**	**12.32**	**13.74**	**13.74**	**13.74**
Electricity Related Losses	8.44	9.67	9.59	9.62	10.10	10.05	10.03	10.85	10.79	10.88
Total	**19.10**	**21.68**	**21.59**	**21.64**	**22.44**	**22.37**	**22.34**	**24.59**	**24.54**	**24.62**
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	0.60	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	4.17	4.17	4.17	4.44	4.44	4.44
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	4.39	4.37	4.40	4.91	4.89	4.90	5.62	5.61	5.62
Delivered Energy	**7.55**	**9.13**	**9.12**	**9.15**	**9.85**	**9.83**	**9.85**	**10.83**	**10.83**	**10.83**
Electricity Related Losses	7.91	9.30	9.23	9.26	10.01	9.96	9.98	10.51	10.47	10.57
Total	**15.46**	**18.44**	**18.35**	**18.41**	**19.86**	**19.79**	**19.83**	**21.34**	**21.30**	**21.40**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.22	1.22	1.31	1.31	1.31	1.49	1.49	1.49
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.53	2.53	2.51	2.85	2.86	2.85
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.28	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	4.44	4.45	4.45	4.71	4.71	4.70	5.02	5.04	5.03
Petroleum Subtotal	9.45	9.86	9.87	9.87	10.57	10.57	10.54	11.63	11.65	11.62
Natural Gas[6]	9.80	10.46	10.46	10.43	11.27	11.29	11.31	12.73	12.74	12.74
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	1.81	1.81	1.80	1.83	1.83	1.80	1.87	1.88	1.86
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.60	2.59	2.59	2.59	2.56	2.60	2.60	2.58
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.61	3.90	3.89	3.90	4.17	4.15	4.16	4.76	4.73	4.75
Delivered Energy	**27.56**	**29.23**	**29.24**	**29.21**	**31.24**	**31.25**	**31.22**	**34.80**	**34.81**	**34.78**
Electricity Related Losses	7.80	8.25	8.20	8.20	8.50	8.44	8.47	8.91	8.84	8.94
Total	**35.36**	**37.48**	**37.44**	**37.42**	**39.74**	**39.70**	**39.70**	**43.71**	**43.65**	**43.72**

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Transportation										
Distillate Fuel	5.13	6.28	6.28	6.27	7.00	7.00	6.99	8.22	8.22	8.22
Jet Fuel[8]	3.46	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Motor Gasoline[2]	15.92	17.67	17.68	17.68	18.97	18.97	18.97	21.26	21.27	21.26
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.30	0.30	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	29.03	29.03	31.68	31.68	31.67	36.73	36.73	36.73
Pipeline Fuel Natural Gas	0.66	0.83	0.84	0.83	0.91	0.91	0.91	1.10	1.10	1.11
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.16	0.16
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	0.01	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**	**30.03**	**30.04**	**30.03**	**32.83**	**32.84**	**32.83**	**38.20**	**38.20**	**38.20**
Electricity Related Losses	0.13	0.19	0.19	0.19	0.24	0.24	0.24	0.31	0.31	0.31
Total	**26.41**	**30.22**	**30.22**	**30.22**	**33.07**	**33.08**	**33.07**	**38.51**	**38.51**	**38.52**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.74	8.74	9.49	9.48	9.48	10.85	10.85	10.84
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.03	3.08	3.08	3.06	3.41	3.42	3.41
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.57	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.24	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.99	4.99	5.35	5.37	5.36
Petroleum Subtotal	37.01	40.90	40.92	40.91	44.16	44.17	44.13	50.21	50.23	50.20
Natural Gas[6]	18.50	20.91	20.92	20.88	22.05	22.07	22.10	24.66	24.69	24.67
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	1.95	1.95	1.92	2.00	2.00	1.98
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.71	2.71	2.71	2.72	2.68	2.72	2.72	2.71
Renewable Energy[13]	2.65	2.94	2.94	2.94	3.18	3.18	3.18	3.65	3.65	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.89	12.96	14.15	14.10	14.12	16.34	16.29	16.32
Delivered Energy	**72.05**	**80.41**	**80.39**	**80.41**	**86.27**	**86.25**	**86.21**	**97.57**	**97.59**	**97.56**
Electricity Related Losses	24.29	27.40	27.22	27.27	28.84	28.69	28.72	30.58	30.41	30.69
Total	**96.33**	**107.81**	**107.61**	**107.68**	**115.11**	**114.94**	**114.94**	**128.16**	**128.00**	**128.25**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.06	0.05	0.06	0.06	0.03	0.06	0.06	0.04
Residual Fuel	0.96	0.38	0.33	0.31	0.22	0.19	0.12	0.19	0.15	0.13
Petroleum Subtotal	1.02	0.44	0.40	0.36	0.28	0.25	0.15	0.25	0.21	0.16
Natural Gas	3.71	5.53	5.51	5.43	6.94	7.03	7.05	11.40	11.40	11.56
Steam Coal	18.77	21.68	21.50	21.70	22.93	22.66	22.65	23.70	23.46	23.60
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.59	6.54
Renewable Energy[15]	3.88	4.19	4.19	4.24	4.73	4.73	4.86	4.78	4.80	4.91
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**	**40.35**	**40.11**	**40.24**	**42.99**	**42.79**	**42.84**	**46.92**	**46.70**	**47.01**

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.80	8.78	9.54	9.54	9.51	10.91	10.90	10.88
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.03	3.08	3.08	3.06	3.41	3.42	3.41
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.57	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.01	1.48	1.43	1.41	1.42	1.39	1.32	1.42	1.39	1.36
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.99	4.99	5.35	5.37	5.36
Petroleum Subtotal	38.02	41.34	41.31	41.27	44.44	44.42	44.28	50.45	50.44	50.37
Natural Gas	22.21	26.44	26.43	26.31	29.00	29.10	29.15	36.06	36.09	36.23
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	23.43	23.61	24.88	24.62	24.57	25.70	25.46	25.58
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	24.21	24.40	25.64	25.38	25.34	26.42	26.18	26.31
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.59	6.54
Renewable Energy[17]	6.54	7.13	7.14	7.19	7.91	7.91	8.05	8.43	8.45	8.56
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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**	**107.81**	**107.61**	**107.68**	**115.11**	**114.94**	**114.94**	**128.16**	**128.00**	**128.25**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.39	80.41	86.27	86.25	86.21	97.57	97.59	97.56
Total Energy Use	96.33	107.81	107.61	107.68	115.11	114.94	114.94	128.16	128.00	128.25
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	10960	10960	10960	12667	12667	12667	16515	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1699.7	1701.5	1825.7	1820.2	1816.4	2051.2	2045.3	2049.0

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Residential	**13.10**	**13.27**	**13.39**	**13.19**	**13.46**	**13.56**	**13.57**	**13.77**	**13.81**	**13.79**
Primary Energy[1]	6.71	7.49	7.48	7.47	7.18	7.19	7.17	7.08	7.07	7.08
Petroleum Products[2]	7.55	9.20	9.15	9.15	9.37	9.36	9.35	9.47	9.46	9.42
Distillate Fuel	6.27	7.45	7.38	7.38	7.57	7.57	7.57	7.78	7.78	7.76
Liquefied Petroleum Gas	10.36	12.60	12.60	12.60	12.86	12.84	12.78	12.75	12.74	12.63
Natural Gas	6.52	7.11	7.11	7.10	6.72	6.74	6.73	6.65	6.64	6.66
Electricity	23.47	22.16	22.54	21.99	22.30	22.53	22.61	22.44	22.59	22.52
Commercial	**13.18**	**12.70**	**12.89**	**12.53**	**12.25**	**12.40**	**12.24**	**12.69**	**12.71**	**12.65**
Primary Energy[1]	5.22	5.57	5.56	5.55	5.68	5.70	5.68	5.79	5.77	5.79
Petroleum Products[2]	4.99	6.13	6.08	6.09	6.29	6.29	6.27	6.40	6.39	6.37
Distillate Fuel	4.37	5.24	5.17	5.17	5.36	5.36	5.36	5.53	5.53	5.52
Residual Fuel	2.63	3.65	3.64	3.64	3.71	3.71	3.69	3.86	3.85	3.85
Natural Gas[3]	5.34	5.55	5.54	5.54	5.66	5.68	5.66	5.78	5.76	5.78
Electricity	21.45	20.26	20.71	19.93	18.76	19.06	18.74	19.00	19.07	18.91
Industrial[4]	**5.27**	**5.76**	**5.78**	**5.69**	**5.67**	**5.70**	**5.64**	**5.90**	**5.90**	**5.87**
Primary Energy	3.91	4.47	4.45	4.45	4.49	4.49	4.46	4.68	4.68	4.65
Petroleum Products[2]	5.54	6.00	5.97	5.97	6.13	6.12	6.07	6.16	6.17	6.10
Distillate Fuel	4.65	5.40	5.34	5.34	5.56	5.56	5.55	5.73	5.72	5.71
Liquefied Petroleum Gas	8.50	7.74	7.74	7.74	7.88	7.85	7.74	7.76	7.78	7.64
Residual Fuel	2.78	3.38	3.37	3.37	3.44	3.43	3.42	3.59	3.58	3.58
Natural Gas[5]	2.79	3.64	3.63	3.63	3.50	3.51	3.49	3.85	3.83	3.84
Metallurgical Coal	1.65	1.58	1.59	1.58	1.54	1.55	1.55	1.44	1.44	1.43
Steam Coal	1.43	1.35	1.35	1.36	1.31	1.31	1.31	1.21	1.21	1.21
Electricity	13.00	12.80	13.10	12.50	12.08	12.31	12.08	12.22	12.29	12.25
Transportation	**8.30**	**9.39**	**9.34**	**9.33**	**9.69**	**9.69**	**9.70**	**9.20**	**9.19**	**9.19**
Primary Energy	8.29	9.38	9.32	9.32	9.68	9.67	9.68	9.18	9.17	9.17
Petroleum Products[2]	8.28	9.37	9.32	9.31	9.67	9.67	9.68	9.18	9.17	9.16
Distillate Fuel[6]	8.22	8.98	8.90	8.90	8.95	8.98	8.95	8.83	8.83	8.83
Jet Fuel[7]	4.70	5.29	5.23	5.23	5.49	5.52	5.49	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.76	10.75	11.31	11.29	11.32	10.60	10.58	10.58
Residual Fuel	2.46	3.11	3.11	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.06	14.06	14.07	14.06	13.96	13.70	13.70	13.59
Natural Gas[10]	7.02	7.28	7.27	7.26	7.21	7.22	7.21	7.41	7.39	7.41
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.16	19.16	19.36	19.35	19.35
Methanol (M85)[12]	10.38	13.13	13.11	13.10	13.83	13.82	13.83	14.35	14.35	14.35
Electricity	15.59	14.52	14.73	14.50	13.62	13.69	13.92	13.22	13.18	13.28
Average End-Use Energy	**8.49**	**9.17**	**9.19**	**9.09**	**9.22**	**9.25**	**9.22**	**9.21**	**9.21**	**9.19**
Primary Energy	6.31	7.19	7.16	7.15	7.35	7.34	7.34	7.23	7.23	7.22
Electricity	19.41	18.65	19.02	18.38	17.99	18.25	18.09	18.19	18.29	18.19
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.63	1.62	1.59	1.61	1.59	1.88	1.88	1.88
Petroleum Products	2.49	3.61	3.65	3.61	3.90	3.97	4.17	4.17	4.27	4.34
Distillate Fuel	4.04	4.72	4.66	4.69	4.87	4.87	4.89	5.06	5.07	5.08
Residual Fuel	2.40	3.42	3.46	3.45	3.65	3.69	3.97	3.89	3.99	4.12
Natural Gas	2.58	3.44	3.43	3.45	3.26	3.25	3.29	3.71	3.68	3.72
Steam Coal	1.21	1.14	1.14	1.13	1.06	1.07	1.04	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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.49	8.49	8.81	8.81	8.81	8.49	8.49	8.48
Distillate Fuel	7.25	8.14	8.07	8.08	8.20	8.22	8.21	8.20	8.20	8.20
Jet Fuel	4.70	5.29	5.23	5.23	5.49	5.52	5.49	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.63	8.63	8.74	8.71	8.63	8.54	8.56	8.42
Motor Gasoline[8]	9.45	10.80	10.76	10.75	11.31	11.29	11.32	10.60	10.58	10.58
Residual Fuel	2.47	3.25	3.25	3.25	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.05	4.72	4.71	4.71	4.47	4.47	4.47	4.60	4.58	4.60
Coal	1.23	1.16	1.16	1.15	1.08	1.09	1.06	1.00	1.00	0.98
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.16	19.16	19.36	19.35	19.35
Methanol (M85)[12]	10.38	13.13	13.11	13.10	13.83	13.82	13.83	14.35	14.35	14.35
Electricity	19.41	18.65	19.02	18.38	17.99	18.25	18.09	18.19	18.29	18.19
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	154.98	153.01	160.41	161.32	161.37	183.27	183.76	183.49
Commercial	98.42	114.97	116.49	113.61	119.69	120.93	119.51	136.41	136.59	135.93
Industrial	111.66	127.05	127.73	125.50	133.28	134.08	132.61	154.57	154.64	153.94
Transportation	212.64	273.84	272.37	272.14	308.81	308.71	308.89	340.45	340.15	340.03
Total Non-Renewable Expenditures	556.99	669.69	671.57	664.26	722.19	725.04	722.39	814.69	815.14	813.39
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.64	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**671.99**	**664.68**	**722.82**	**725.68**	**723.02**	**815.54**	**815.99**	**814.24**

[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.
SO_2 = Sulfur 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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Supply, Disposition, and Prices	1999	2005 Reference	2005 NO_x 2008	2005 SO_2 2008	2010 Reference	2010 NO_x 2008	2010 SO_2 2008	2020 Reference	2020 NO_x 2008	2020 SO_2 2008
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	2092	2104	2245	2218	2187	2315	2288	2270
Petroleum	94	43	39	35	28	25	16	25	21	17
Natural Gas[2]	359	583	584	595	825	839	878	1495	1503	1535
Nuclear Power	730	740	740	740	725	725	725	613	617	613
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	373	377	397	396	406	400	400	409
Total	**3369**	**3844**	**3827**	**3850**	**4219**	**4203**	**4211**	**4847**	**4829**	**4842**
Non-Utility Generation for Own Use	16	17	17	17	17	17	16	17	17	16
Distributed Generation	0	0	0	0	1	1	1	5	5	5
Cogenerators[4]										
Coal	47	53	53	53	52	52	50	52	52	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	207	237	240	235	261	266	257	318	329	319
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	8
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	6	6	5
Total	**303**	**345**	**348**	**343**	**373**	**379**	**368**	**441**	**452**	**442**
Other End-Use Generators	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	172	173	171	180	181	176	208	211	207
Generation for Own Use	156	178	180	177	198	203	197	238	246	240
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1339	1332	1340	1452	1447	1444	1698	1694	1696
Commercial	1073	1288	1282	1290	1439	1434	1437	1646	1644	1647
Industrial	1058	1142	1139	1143	1222	1216	1221	1395	1387	1393
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3294**	**3794**	**3779**	**3799**	**4147**	**4132**	**4137**	**4788**	**4774**	**4784**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.7	7.5	7.6	7.7	7.7	7.7	7.7	7.7
Commercial	7.3	6.9	7.1	6.8	6.4	6.5	6.4	6.5	6.5	6.5
Industrial	4.4	4.4	4.5	4.3	4.1	4.2	4.1	4.2	4.2	4.2
Transportation	5.3	5.0	5.0	4.9	4.6	4.7	4.7	4.5	4.5	4.5
All Sectors Average	**6.6**	**6.4**	**6.5**	**6.3**	**6.1**	**6.2**	**6.2**	**6.2**	**6.2**	**6.2**
Prices by Service Category[9] (1999 cents/kwh)										
Generation	4.1	3.8	3.9	3.7	3.5	3.5	3.5	3.6	3.6	3.6
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	13.71	10.38	10.39	9.46	9.70	9.70	3.57	8.95	8.95	3.27
Nitrogen Oxide	5.45	4.30	3.12	4.27	4.34	1.62	4.26	4.49	1.64	4.49

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

Table B5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	2005 Reference	2005 NO_x 2008	2005 SO_2 2008	2010 Reference	2010 NO_x 2008	2010 SO_2 2008	2020 Reference	2020 NO_x 2008	2020 SO_2 2008
		Projections								
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.6	304.1	318.6	314.3	317.0	318.5	313.8	316.3
Other Fossil Steam[3]	137.4	127.8	127.5	124.6	119.2	116.4	109.8	116.9	114.6	108.7
Combined Cycle	21.0	53.2	54.9	71.3	107.8	110.6	130.9	202.2	208.0	213.2
Combustion Turbine/Diesel	74.3	123.1	119.3	115.4	147.2	147.6	134.2	199.5	199.8	197.9
Nuclear Power	97.4	97.5	97.5	97.5	94.8	94.8	94.8	76.3	76.9	76.3
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	94.8	94.8	94.8	98.0	98.0	98.4	99.5	99.5	99.9
Distributed Generation[5]	0.0	0.7	0.7	0.4	2.5	2.5	2.2	11.5	11.4	12.2
Total	**743.4**	**820.4**	**817.7**	**827.6**	**907.8**	**904.0**	**907.0**	**1044.2**	**1043.7**	**1044.2**
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	0.8	1.3	18.9	14.6	19.1	20.5	15.8	20.3
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	19.4	21.1	37.5	74.2	77.0	97.3	168.6	174.3	179.6
Combustion Turbine/Diesel	0.0	38.9	35.3	31.4	64.7	65.2	51.6	117.2	117.6	115.4
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	0.5	0.5	2.0	2.0	2.4	2.0	2.1	2.5
Distributed Generation[5]	0.0	0.7	0.7	0.4	2.5	2.5	2.2	11.5	11.4	12.2
Total	**0.0**	**60.6**	**58.4**	**71.1**	**162.2**	**161.4**	**172.6**	**319.8**	**321.2**	**329.8**
Cumulative Total Additions	**0.0**	**92.6**	**90.4**	**103.1**	**195.9**	**195.1**	**206.3**	**355.1**	**356.5**	**365.1**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	5.4	7.3	7.2	7.1	9.1
Other Fossil Steam[3]	0.0	9.9	10.1	13.1	18.4	21.2	27.8	20.7	23.0	29.0
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	4.4	4.5	4.5	6.0	6.2	5.9	6.3	6.3	6.0
Nuclear Power	0.0	0.0	0.0	0.0	2.6	2.6	2.6	21.2	20.6	21.2
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	16.7	17.1	20.1	32.8	35.7	44.0	55.6	57.4	65.6
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	8.6	8.4	8.6	8.6	8.4
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	39.9	40.2	39.8	43.3	44.0	43.1	51.4	52.7	51.6
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	8.2	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**59.5**	**59.1**	**63.3**	**64.0**	**62.9**	**73.2**	**74.5**	**73.2**
Cumulative Additions[6]	**0.0**	**6.8**	**7.1**	**6.7**	**10.9**	**11.6**	**10.4**	**20.7**	**22.1**	**20.8**

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

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
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	152.0	202.3	196.1	226.4	155.5	157.0	141.5	147.9	146.4	127.9
Gross Domestic Trade	**334.2**	**327.6**	**321.4**	**351.7**	**258.4**	**260.0**	**244.5**	**147.9**	**146.4**	**127.9**
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)	4413.9	6468.6	6609.7	6918.8	4510.4	4665.6	4000.2	4605.1	4603.1	3975.6
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**12515.5**	**12824.6**	**9361.6**	**9516.8**	**8851.5**	**4605.1**	**4603.1**	**3975.6**
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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Production										
Dry Gas Production[1]	18.67	21.40	21.39	21.27	23.43	23.52	23.53	29.47	29.53	29.62
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**	**4.69**	**4.69**	**4.69**	**5.00**	**5.01**	**5.06**	**5.82**	**5.82**	**5.86**
Canada	3.29	4.48	4.48	4.47	4.72	4.73	4.77	5.43	5.42	5.46
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	0.80	0.80
Total Supply	**22.15**	**26.20**	**26.19**	**26.07**	**28.49**	**28.59**	**28.65**	**35.35**	**35.40**	**35.53**
Consumption by Sector										
Residential	4.75	5.42	5.43	5.43	5.46	5.47	5.47	6.07	6.08	6.07
Commercial	3.06	3.88	3.88	3.88	4.06	4.06	4.06	4.32	4.33	4.32
Industrial[3]	8.31	8.81	8.81	8.79	9.48	9.49	9.51	10.53	10.54	10.53
Electric Generators[4]	3.64	5.43	5.41	5.33	6.81	6.90	6.92	11.19	11.19	11.34
Lease and Plant Fuel[5]	1.23	1.38	1.38	1.37	1.50	1.50	1.50	1.87	1.87	1.88
Pipeline Fuel	0.64	0.81	0.82	0.81	0.88	0.89	0.89	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	**21.65**	**25.79**	**25.78**	**25.66**	**28.29**	**28.39**	**28.44**	**35.20**	**35.24**	**35.37**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.41**	**0.20**	**0.20**	**0.21**	**0.14**	**0.16**	**0.16**

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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, M2NOX08.D060801A, M2SO208P.D061201A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.95	2.95	2.87	2.88	2.86	3.22	3.20	3.22
Average Import Price	2.29	2.95	2.95	2.94	2.64	2.65	2.65	2.72	2.72	2.73
Average[2]	**2.11**	**2.96**	**2.95**	**2.95**	**2.82**	**2.84**	**2.82**	**3.13**	**3.11**	**3.13**
Delivered Prices										
Residential	6.69	7.31	7.30	7.29	6.91	6.92	6.91	6.83	6.82	6.83
Commercial	5.49	5.70	5.69	5.69	5.82	5.83	5.82	5.93	5.92	5.94
Industrial[3]	2.87	3.74	3.73	3.72	3.59	3.60	3.58	3.95	3.93	3.95
Electric Generators[4]	2.63	3.50	3.49	3.51	3.32	3.31	3.35	3.78	3.75	3.79
Transportation[5]	7.21	7.48	7.47	7.46	7.40	7.42	7.40	7.61	7.59	7.61
Average[6]	**4.15**	**4.84**	**4.83**	**4.84**	**4.59**	**4.59**	**4.58**	**4.72**	**4.70**	**4.72**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.35	4.08	4.09	4.09	3.70	3.70	3.71
Commercial	3.37	2.74	2.74	2.74	2.99	3.00	3.00	2.81	2.81	2.81
Industrial[3]	0.76	0.78	0.78	0.78	0.77	0.77	0.76	0.82	0.82	0.82
Electric Generators[4]	0.52	0.54	0.54	0.57	0.49	0.48	0.53	0.65	0.64	0.66
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.58	4.58	4.48	4.48	4.48
Average[6]	**2.04**	**1.88**	**1.88**	**1.89**	**1.76**	**1.75**	**1.77**	**1.59**	**1.59**	**1.59**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.59	23.59	22.30	22.33	22.35	22.48	22.52	22.50
Commercial	10.32	10.63	10.64	10.64	12.16	12.16	12.18	12.12	12.14	12.12
Industrial[3]	6.28	6.86	6.86	6.83	7.26	7.27	7.26	8.65	8.62	8.61
Electric Generators[4]	1.88	2.94	2.91	3.01	3.36	3.28	3.66	7.24	7.12	7.50
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.41	0.41	0.68	0.68	0.68
Total	**40.32**	**44.25**	**44.23**	**44.31**	**45.49**	**45.45**	**45.85**	**51.18**	**51.08**	**51.41**

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

Table B9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per barrel)	**16.49**	**21.43**	**20.56**	**21.92**	**20.73**	**20.77**	**20.79**	**21.47**	**21.48**	**21.49**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.66**	**5.67**	**5.66**	**5.32**	**5.30**	**5.32**	**5.25**	**5.25**	**5.26**
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.51	2.51	2.75	2.74	2.75
Conventional	2.59	2.18	2.18	2.18	1.81	1.81	1.81	1.98	1.98	1.98
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.69	0.70	0.76	0.76	0.77
Lower 48 Offshore	1.56	2.06	2.07	2.06	2.16	2.15	2.16	1.87	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**	**15.75**	**15.73**	**15.76**	**14.55**	**14.47**	**14.52**	**14.11**	**14.09**	**14.15**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.95**	**2.95**	**2.87**	**2.88**	**2.86**	**3.22**	**3.20**	**3.22**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.40**	**21.39**	**21.27**	**23.43**	**23.52**	**23.53**	**29.47**	**29.53**	**29.62**
Lower 48 Onshore	12.83	14.46	14.44	14.38	16.71	16.77	16.81	21.31	21.13	21.21
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.32	1.32	1.39	1.39	1.40
Non-Associated	11.03	12.95	12.93	12.86	15.39	15.45	15.48	19.91	19.74	19.82
Conventional	6.64	7.67	7.67	7.62	7.93	7.98	8.06	11.14	10.95	11.03
Unconventional	4.39	5.27	5.26	5.25	7.45	7.47	7.42	8.78	8.78	8.79
Lower 48 Offshore	5.43	6.47	6.48	6.43	6.22	6.24	6.22	7.59	7.83	7.83
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	5.41	5.42	5.37	5.13	5.15	5.13	6.56	6.79	6.80
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**	**167.88**	**167.98**	**167.97**	**185.55**	**184.76**	**184.95**	**200.71**	**200.33**	**199.99**
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**	**28.87**	**28.97**	**28.69**	**29.86**	**30.05**	**30.02**	**39.36**	**39.44**	**39.60**

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Production[1]										
Appalachia	433	426	424	437	421	420	449	396	396	397
Interior	185	182	181	193	180	177	180	161	167	168
West	486	624	619	593	694	682	636	783	763	764
East of the Mississippi	559	561	557	583	557	554	586	524	529	536
West of the Mississippi	544	672	667	641	738	725	678	817	797	793
Total	**1103**	**1233**	**1224**	**1223**	**1295**	**1279**	**1265**	**1340**	**1325**	**1329**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	58	57	56	56	55
Total	**-49**	**-44**	**-44**	**-44**	**-40**	**-40**	**-40**	**-36**	**-36**	**-36**
Total Supply[2]	**1054**	**1189**	**1180**	**1179**	**1254**	**1239**	**1224**	**1304**	**1289**	**1294**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	83	82	83	84	82	86	86	85
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1068	1068	1145	1129	1117	1196	1181	1185
Total	**1032**	**1189**	**1181**	**1180**	**1256**	**1241**	**1228**	**1306**	**1291**	**1294**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-2**	**-2**	**-3**	**-2**	**-2**	**-1**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	15.06	15.49	14.08	14.18	14.81	12.87	13.02	13.00
(1999 dollars per million Btu)	0.82	0.73	0.73	0.74	0.69	0.69	0.71	0.64	0.64	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.67	29.81	28.61	28.69	28.69	26.50	26.55	26.38
Coke Plants	44.28	42.39	42.51	42.37	41.36	41.42	41.45	38.52	38.65	38.42
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	22.91	22.96	21.28	21.45	21.05	19.41	19.52	19.09
(1999 dollars per million Btu)	1.21	1.14	1.14	1.13	1.06	1.07	1.04	0.98	0.98	0.96
Average	**25.77**	**23.78**	**23.80**	**23.85**	**22.13**	**22.31**	**21.94**	**20.15**	**20.27**	**19.85**
Exports[7]	37.44	36.39	36.45	36.41	35.66	35.72	35.52	33.09	33.18	32.66

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
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	3.43	3.46	3.53	4.93	5.01	5.13	4.95	5.07	5.15
Municipal Solid Waste[3]	2.61	2.96	2.96	2.91	3.42	3.36	3.65	3.93	3.87	4.16
Wood and Other Biomass[4]	1.57	1.75	1.75	1.75	2.12	2.12	2.12	2.45	2.45	2.45
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	7.76	7.76	7.77
Total	**88.83**	**94.75**	**94.79**	**94.80**	**97.98**	**97.99**	**98.41**	**99.49**	**99.55**	**99.92**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.20	301.20	301.13	301.13	301.13	300.07	300.07	300.07
Geothermal[2]	13.21	18.34	18.59	19.10	30.94	31.56	32.58	31.16	32.12	32.79
Municipal Solid Waste[3]	18.12	20.68	20.70	20.33	23.88	23.35	25.69	27.76	27.23	29.57
Wood and Other Biomass[4]	9.02	14.94	14.88	18.47	21.30	20.31	26.98	19.78	19.43	24.57
Dedicated Plants	7.73	9.16	9.16	9.16	11.36	11.36	11.37	13.82	13.82	13.82
Cofiring	1.29	5.78	5.72	9.31	9.94	8.95	15.61	5.95	5.61	10.74
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	18.83	18.84	18.84
Total	**355.43**	**372.61**	**372.82**	**376.55**	**397.03**	**396.12**	**406.16**	**400.32**	**400.42**	**408.57**
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	5.17	5.17	5.17	6.06	6.06	6.06	7.54	7.54	7.54
Total	**5.35**	**5.87**	**5.87**	**5.87**	**6.76**	**6.76**	**6.76**	**8.24**	**8.24**	**8.24**
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	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.12**	**33.97**	**33.97**	**33.97**	**39.05**	**39.05**	**39.05**	**47.57**	**47.57**	**47.57**
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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.44**	**0.44**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	0.44	0.44
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**	**2.42**	**2.42**	**2.42**	**2.64**	**2.64**	**2.64**	**3.08**	**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	2.23	2.23	2.23	2.46	2.46	2.46	2.90	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.21**	**0.22**	**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**	**4.19**	**4.19**	**4.24**	**4.73**	**4.73**	**4.86**	**4.78**	**4.80**	**4.91**
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	0.44	0.45	0.47	0.85	0.87	0.90	0.85	0.88	0.90
Municipal Solid Waste[6]	0.25	0.28	0.28	0.28	0.32	0.32	0.35	0.38	0.37	0.40
Biomass	0.12	0.18	0.18	0.22	0.26	0.24	0.32	0.25	0.24	0.30
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.14	0.13	0.17	0.17	0.17
Cofiring	0.02	0.07	0.07	0.11	0.12	0.11	0.18	0.07	0.07	0.13
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**	**7.31**	**7.31**	**7.36**	**8.10**	**8.09**	**8.23**	**8.62**	**8.64**	**8.75**
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	0.20	0.19	0.20	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**	**0.22**	**0.21**	**0.22**	**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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.5	23.2	23.3	23.3
Natural Gas	69.5	80.2	80.3	80.3	80.8	80.8	80.8	89.8	89.9	89.8
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	227.1	224.8	225.8	242.6	240.5	238.9	275.6	273.2	274.6
Total	**290.1**	**335.0**	**332.8**	**333.8**	**349.2**	**347.1**	**345.5**	**389.8**	**387.6**	**388.9**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.0	12.0	12.1	12.0	12.0
Natural Gas	45.4	57.4	57.4	57.4	60.1	60.0	60.1	63.9	64.0	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	218.4	216.4	217.5	240.4	238.3	237.7	267.1	265.1	266.7
Total	**242.1**	**289.4**	**287.4**	**288.5**	**314.3**	**312.2**	**311.6**	**345.0**	**343.0**	**344.6**
Industrial[1]										
Petroleum	104.2	99.2	99.4	99.3	105.3	105.5	104.8	113.6	114.0	113.5
Natural Gas[2]	141.6	148.4	148.4	148.0	159.8	160.0	160.4	180.3	180.7	180.6
Coal	55.9	65.8	65.8	65.7	65.6	65.7	64.9	65.8	66.0	65.5
Electricity	178.8	193.6	192.2	192.6	204.1	202.1	201.8	226.4	223.7	225.6
Total	**480.4**	**507.0**	**505.9**	**505.6**	**534.8**	**533.3**	**532.0**	**586.1**	**584.3**	**585.3**
Transportation										
Petroleum[3]	485.8	556.3	556.4	556.3	607.2	607.3	607.1	704.2	704.3	704.1
Natural Gas[4]	9.5	12.8	12.8	12.8	14.4	14.4	14.4	18.1	18.1	18.2
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	4.4	4.4	5.8	5.7	5.7	7.9	7.8	7.9
Total[3]	**498.2**	**573.6**	**573.6**	**573.5**	**627.5**	**627.6**	**627.3**	**730.2**	**730.3**	**730.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	694.1	694.0	749.0	749.3	748.4	853.1	853.5	853.0
Natural Gas	266.0	298.8	299.0	298.4	315.1	315.3	315.7	352.0	352.8	352.5
Coal	58.8	68.8	68.8	68.7	68.8	68.9	68.1	69.0	69.1	68.7
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	643.6	637.8	640.3	692.8	686.6	684.1	777.0	769.8	774.7
Total[3]	**1510.8**	**1705.0**	**1699.7**	**1701.5**	**1825.7**	**1820.2**	**1816.4**	**2051.2**	**2045.3**	**2049.0**
Electric Generators[6]										
Petroleum	20.0	9.4	8.3	7.6	5.8	5.3	3.2	5.2	4.4	3.4
Natural Gas	45.8	79.6	79.3	78.2	100.0	101.2	101.5	164.1	164.2	166.4
Coal	490.5	554.6	550.1	554.6	587.0	580.2	579.3	607.7	601.2	604.9
Total	**556.3**	**643.6**	**637.8**	**640.3**	**692.8**	**686.6**	**684.1**	**777.0**	**769.8**	**774.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	702.4	701.6	754.8	754.6	751.6	858.3	857.9	856.4
Natural Gas	311.8	378.4	378.3	376.6	415.0	416.4	417.3	516.2	517.0	518.9
Coal	549.3	623.3	618.9	623.2	655.8	649.1	647.4	676.7	670.4	673.6
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**	**1705.0**	**1699.7**	**1701.5**	**1825.7**	**1820.2**	**1816.4**	**2051.2**	**2045.3**	**2049.0**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.1**	**6.1**	**6.3**	**6.3**	**6.3**

[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.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

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

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.12	4.27	4.34	1.62	4.26	4.49	1.64	4.49
Sulfur Dioxide (million tons)	13.71	10.38	10.39	9.46	9.70	9.70	3.57	8.95	8.95	3.27
Mercury (tons)	43.60	45.24	44.70	42.53	45.60	44.07	31.86	45.07	43.53	32.51
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	637.78	640.32	692.78	686.63	684.10	776.99	769.78	774.73
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	2144	1302	4391	2405	3668	5037	3201	5229
Sulfur Dioxide (1999 dollars per ton)	0	190	192	162	187	198	794	241	203	983
Mercury (million 1999 dollars per ton)	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	0
Retrofits (gigawatts)										
Scrubber[1]	0.0	6.5	6.1	25.0	7.1	6.1	124.7	14.8	18.7	139.4
Combustion	0.0	39.9	53.4	41.2	42.1	62.4	46.2	46.1	68.7	49.2
SCR Post-combustion	0.0	92.8	87.7	84.7	92.9	236.5	84.8	93.0	242.3	85.8
SNCR Post-combustion	0.0	25.2	0.3	38.3	26.3	22.3	38.5	43.4	31.9	45.0
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	589	561	642	639	527	721	705	636
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	451	464	464	456	509	440	439	494
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	184	198	188	184	229	179	182	199

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxide.
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 M2BASE.D060801A, M2NOX08.D060801A, M2SO208P.D061201A.

Appendix C

Tables for CO_2 1990-7% Cap 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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Production							
Crude Oil and Lease Condensate	12.45	11.98	12.02	11.27	11.19	11.12	11.31
Natural Gas Plant Liquids	2.62	3.12	3.02	3.37	3.57	4.16	4.30
Dry Natural Gas	19.16	21.95	21.28	24.04	25.48	30.24	31.31
Coal	23.08	25.45	24.30	26.55	15.16	27.16	13.52
Nuclear Power	7.79	7.90	7.90	7.74	7.95	6.54	7.44
Renewable Energy[1]	6.53	7.13	8.29	7.90	10.08	8.42	10.94
Other[2]	1.65	0.35	0.58	0.31	0.31	0.33	0.33
Total	**73.29**	**77.88**	**77.40**	**81.19**	**73.73**	**87.97**	**79.16**
Imports							
Crude Oil[3]	18.96	21.42	21.38	22.38	22.51	25.82	25.80
Petroleum Products[4]	4.14	6.28	5.87	8.65	8.01	10.80	10.25
Natural Gas	3.63	5.13	5.10	5.55	6.84	6.59	8.18
Other Imports[5]	0.64	1.11	1.02	0.96	0.89	0.96	0.81
Total	**27.37**	**33.93**	**33.37**	**37.54**	**38.24**	**44.18**	**45.03**
Exports							
Petroleum[6]	1.98	1.73	1.75	1.69	1.71	1.85	1.83
Natural Gas	0.17	0.33	0.33	0.43	0.12	0.63	0.12
Coal	1.48	1.51	1.51	1.45	1.44	1.41	1.44
Total	**3.62**	**3.57**	**3.59**	**3.58**	**3.27**	**3.89**	**3.40**
Discrepancy[7]	**0.69**	**0.43**	**0.56**	**0.04**	**0.03**	**0.11**	**-0.04**
Consumption							
Petroleum Products[8]	38.02	41.34	40.92	44.44	44.03	50.45	50.25
Natural Gas	22.21	26.44	25.74	29.00	32.01	36.06	39.21
Coal	21.42	24.39	23.16	25.64	14.08	26.42	12.62
Nuclear Power	7.79	7.90	7.90	7.74	7.95	6.54	7.44
Renewable Energy[1]	6.54	7.13	8.30	7.91	10.08	8.43	10.95
Other[9]	0.35	0.61	0.61	0.38	0.52	0.25	0.38
Total	**96.33**	**107.81**	**106.63**	**115.11**	**108.68**	**128.16**	**120.84**
Net Imports - Petroleum	**21.12**	**25.96**	**25.50**	**29.34**	**28.81**	**34.78**	**34.21**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.22	20.83	20.83	21.37	21.37	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.96	2.79	2.87	3.36	3.22	3.74
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.74	14.08	14.22	12.87	12.77
Average Electric Price (cents per Kwh)	6.6	6.4	6.8	6.1	8.8	6.2	8.6

[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 M2BASE.D060801A, M2C7B08.D060801A.

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

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Energy Consumption							
Residential							
Distillate Fuel	0.86	0.87	0.87	0.80	0.81	0.76	0.77
Kerosene	0.10	0.08	0.08	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.45	0.45	0.42	0.42	0.40	0.41
Petroleum Subtotal	1.42	1.40	1.40	1.30	1.30	1.23	1.25
Natural Gas	4.88	5.57	5.60	5.61	5.55	6.23	6.25
Coal	0.04	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	0.44	0.43
Electricity	3.91	4.57	4.49	4.95	4.51	5.79	5.26
Delivered Energy	**10.66**	**12.01**	**11.96**	**12.34**	**11.84**	**13.74**	**13.24**
Electricity Related Losses	8.44	9.67	9.38	10.10	8.28	10.85	8.78
Total	**19.10**	**21.68**	**21.35**	**22.44**	**20.12**	**24.59**	**22.02**
Commercial							
Distillate Fuel	0.36	0.37	0.37	0.38	0.38	0.37	0.39
Residual Fuel	0.10	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
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.60	0.60	0.60	0.62	0.62	0.62	0.63
Natural Gas	3.14	3.99	4.01	4.17	4.15	4.44	5.09
Coal	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
Electricity	3.66	4.39	4.33	4.91	4.51	5.62	4.96
Delivered Energy	**7.55**	**9.13**	**9.10**	**9.85**	**9.44**	**10.83**	**10.85**
Electricity Related Losses	7.91	9.30	9.05	10.01	8.28	10.51	8.28
Total	**15.46**	**18.44**	**18.15**	**19.86**	**17.72**	**21.34**	**19.13**
Industrial[4]							
Distillate Fuel	1.13	1.22	1.21	1.31	1.29	1.49	1.49
Liquefied Petroleum Gas	2.32	2.45	2.42	2.53	2.56	2.85	2.88
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	0.22	0.16	0.16	0.25	0.26	0.28	0.29
Motor Gasoline[2]	0.21	0.23	0.23	0.25	0.24	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.41	4.71	4.73	5.02	5.09
Petroleum Subtotal	9.45	9.86	9.79	10.57	10.60	11.63	11.72
Natural Gas[6]	9.80	10.46	10.44	11.27	11.37	12.73	13.49
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	1.73	1.81	1.80	1.83	1.78	1.87	1.83
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.53	2.60	2.55
Renewable Energy[7]	2.15	2.42	2.41	2.64	2.63	3.08	3.08
Electricity	3.61	3.90	3.83	4.17	3.84	4.76	3.95
Delivered Energy	**27.56**	**29.23**	**29.05**	**31.24**	**30.97**	**34.80**	**34.79**
Electricity Related Losses	7.80	8.25	8.00	8.50	7.04	8.91	6.59
Total	**35.36**	**37.48**	**37.05**	**39.74**	**38.01**	**43.71**	**41.38**

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

Sector and Source	1999	Projections 2005 Reference	2005 CO_2 1990-7% 2008	2010 Reference	2010 CO_2 1990-7% 2008	2020 Reference	2020 CO_2 1990-7% 2008
Transportation							
Distillate Fuel	5.13	6.28	6.23	7.00	6.86	8.22	8.10
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.48	5.97	5.96
Motor Gasoline[2]	15.92	17.67	17.63	18.97	18.88	21.26	21.19
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.87	0.86
Liquefied Petroleum Gas	0.02	0.03	0.03	0.04	0.04	0.06	0.06
Other Petroleum[9]	0.26	0.30	0.29	0.31	0.31	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.92	31.68	31.42	36.73	36.53
Pipeline Fuel Natural Gas	0.66	0.83	0.81	0.91	0.95	1.10	1.14
Compressed Natural Gas	0.02	0.06	0.05	0.09	0.09	0.16	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.03	0.03	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.09	0.09	0.12	0.12	0.17	0.17
Delivered Energy	**26.28**	**30.03**	**29.90**	**32.83**	**32.62**	**38.20**	**38.04**
Electricity Related Losses	0.13	0.19	0.18	0.24	0.22	0.31	0.28
Total	**26.41**	**30.22**	**30.08**	**33.07**	**32.83**	**38.51**	**38.31**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.48	8.74	8.68	9.49	9.34	10.85	10.74
Kerosene	0.15	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.48	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.08	3.11	3.41	3.45
Motor Gasoline[2]	16.17	17.93	17.89	19.24	19.15	21.57	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	1.05	1.10	1.10	1.20	1.21	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.68	4.99	5.01	5.35	5.42
Petroleum Subtotal	37.01	40.90	40.72	44.16	43.94	50.21	50.14
Natural Gas[6]	18.50	20.91	20.91	22.05	22.11	24.66	26.13
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.95	1.90	2.00	1.95
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	2.65	2.71	2.70	2.71	2.66	2.72	2.67
Renewable Energy[13]	2.65	2.94	2.93	3.18	3.17	3.65	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.24	12.95	12.74	14.15	12.98	16.34	14.35
Delivered Energy	**72.05**	**80.41**	**80.01**	**86.27**	**84.86**	**97.57**	**96.92**
Electricity Related Losses	24.29	27.40	26.62	28.84	23.81	30.58	23.92
Total	**96.33**	**107.81**	**106.63**	**115.11**	**108.68**	**128.16**	**120.84**
Electric Generators[14]							
Distillate Fuel	0.06	0.06	0.03	0.06	0.02	0.06	0.02
Residual Fuel	0.96	0.38	0.17	0.22	0.07	0.19	0.09
Petroleum Subtotal	1.02	0.44	0.20	0.28	0.09	0.25	0.11
Natural Gas	3.71	5.53	4.83	6.94	9.90	11.40	13.08
Steam Coal	18.77	21.68	20.46	22.93	11.43	23.70	9.95
Nuclear Power	7.79	7.90	7.90	7.74	7.95	6.54	7.44
Renewable Energy[15]	3.88	4.19	5.36	4.73	6.92	4.78	7.32
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.51	0.24	0.37
Total	**35.52**	**40.35**	**39.36**	**42.99**	**36.79**	**46.92**	**38.27**

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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Total Energy Consumption							
Distillate Fuel	7.54	8.80	8.71	9.54	9.35	10.91	10.76
Kerosene	0.15	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.48	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.08	3.11	3.41	3.45
Motor Gasoline[2]	16.17	17.93	17.89	19.24	19.15	21.57	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	2.01	1.48	1.28	1.42	1.28	1.42	1.34
Other Petroleum[12]	4.53	4.71	4.68	4.99	5.01	5.35	5.42
Petroleum Subtotal	38.02	41.34	40.92	44.44	44.03	50.45	50.25
Natural Gas	22.21	26.44	25.74	29.00	32.01	36.06	39.21
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	20.61	23.60	22.37	24.88	13.33	25.70	11.90
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	21.42	24.39	23.16	25.64	14.08	26.42	12.62
Nuclear Power	7.79	7.90	7.90	7.74	7.95	6.54	7.44
Renewable Energy[17]	6.54	7.13	8.30	7.91	10.09	8.43	10.95
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.51	0.24	0.37
Total	**96.33**	**107.81**	**106.63**	**115.11**	**108.68**	**128.16**	**120.84**
Energy Use and Related Statistics							
Delivered Energy Use	72.05	80.41	80.01	86.27	84.86	97.57	96.92
Total Energy Use	96.33	107.81	106.63	115.11	108.68	128.16	120.84
Population (millions)	273.13	288.02	288.02	300.17	300.17	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10960	10903	12667	12611	16515	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1655.8	1825.7	1564.5	2051.2	1737.7

[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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A.

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

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Residential	**13.10**	**13.27**	**13.62**	**13.46**	**16.45**	**13.77**	**16.28**
Primary Energy[1]	6.71	7.49	7.37	7.18	7.55	7.08	7.45
Petroleum Products[2]	7.55	9.20	9.15	9.37	9.37	9.47	9.43
Distillate Fuel	6.27	7.45	7.37	7.57	7.56	7.78	7.74
Liquefied Petroleum Gas	10.36	12.60	12.59	12.86	12.91	12.75	12.65
Natural Gas	6.52	7.11	6.97	6.72	7.18	6.65	7.11
Electricity	23.47	22.16	23.45	22.30	30.07	22.44	28.95
Commercial	**13.18**	**12.70**	**13.33**	**12.25**	**16.44**	**12.69**	**15.59**
Primary Energy[1]	5.22	5.57	5.44	5.68	6.06	5.79	6.16
Petroleum Products[2]	4.99	6.13	6.08	6.29	6.27	6.40	6.32
Distillate Fuel	4.37	5.24	5.16	5.36	5.32	5.53	5.48
Residual Fuel	2.63	3.65	3.62	3.71	3.69	3.86	3.84
Natural Gas[3]	5.34	5.55	5.41	5.66	6.11	5.78	6.21
Electricity	21.45	20.26	21.86	18.76	27.59	19.00	26.61
Industrial[4]	**5.27**	**5.76**	**5.83**	**5.67**	**6.74**	**5.90**	**6.66**
Primary Energy	3.91	4.47	4.38	4.49	4.69	4.68	4.85
Petroleum Products[2]	5.54	6.00	5.95	6.13	6.11	6.16	6.10
Distillate Fuel	4.65	5.40	5.33	5.56	5.49	5.73	5.69
Liquefied Petroleum Gas	8.50	7.74	7.72	7.88	7.94	7.76	7.71
Residual Fuel	2.78	3.38	3.35	3.44	3.42	3.59	3.58
Natural Gas[5]	2.79	3.64	3.49	3.50	3.97	3.85	4.33
Metallurgical Coal	1.65	1.58	1.58	1.54	1.55	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.31	1.21	1.21	1.09
Electricity	13.00	12.80	13.92	12.08	18.93	12.22	18.34
Transportation	**8.30**	**9.39**	**9.35**	**9.69**	**9.77**	**9.20**	**9.22**
Primary Energy	8.29	9.38	9.33	9.68	9.74	9.18	9.19
Petroleum Products[2]	8.28	9.37	9.33	9.67	9.73	9.18	9.18
Distillate Fuel[6]	8.22	8.98	8.89	8.95	8.94	8.83	8.82
Jet Fuel[7]	4.70	5.29	5.23	5.49	5.48	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.77	11.31	11.42	10.60	10.61
Residual Fuel	2.46	3.11	3.10	3.18	3.17	3.33	3.32
Liquid Petroleum Gas[9]	12.87	14.07	14.04	14.07	14.17	13.70	13.61
Natural Gas[10]	7.02	7.28	7.13	7.21	7.67	7.41	7.83
Ethanol (E85)[11]	14.42	19.21	19.19	19.16	19.31	19.36	19.43
Methanol (M85)[12]	10.38	13.13	12.99	13.83	13.84	14.35	14.42
Electricity	15.59	14.52	15.12	13.62	18.08	13.22	16.65
Average End-Use Energy	**8.49**	**9.17**	**9.30**	**9.22**	**10.51**	**9.21**	**10.15**
Primary Energy	6.31	7.19	7.11	7.35	7.50	7.23	7.32
Electricity	19.41	18.65	19.99	17.99	25.81	18.19	25.08
Electric Generators[13]							
Fossil Fuel Average	1.48	1.64	1.53	1.59	2.39	1.88	2.89
Petroleum Products	2.49	3.61	3.75	3.90	4.37	4.17	4.44
Distillate Fuel	4.04	4.72	4.74	4.87	4.89	5.06	5.09
Residual Fuel	2.40	3.42	3.59	3.65	4.24	3.89	4.30
Natural Gas	2.58	3.44	3.37	3.26	4.05	3.71	4.44
Steam Coal	1.21	1.14	1.07	1.06	0.93	0.98	0.84

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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Average Price to All Users[14]							
Petroleum Products[2]	7.44	8.53	8.51	8.81	8.86	8.49	8.49
Distillate Fuel	7.25	8.14	8.07	8.20	8.19	8.20	8.18
Jet Fuel	4.70	5.29	5.23	5.49	5.48	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.62	8.74	8.80	8.54	8.49
Motor Gasoline[8]	9.45	10.80	10.77	11.31	11.42	10.60	10.61
Residual Fuel	2.47	3.25	3.23	3.33	3.32	3.49	3.48
Natural Gas	4.05	4.72	4.63	4.47	4.91	4.60	5.13
Coal	1.23	1.16	1.10	1.08	0.97	1.00	0.88
Ethanol (E85)[11]	14.42	19.21	19.19	19.16	19.31	19.36	19.43
Methanol (M85)[12]	10.38	13.13	12.99	13.83	13.84	14.35	14.42
Electricity	19.41	18.65	19.99	17.99	25.81	18.19	25.08
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)							
Residential	134.28	153.83	157.22	160.41	187.74	183.27	208.65
Commercial	98.42	114.97	120.19	119.69	153.84	136.41	167.83
Industrial	111.66	127.05	128.36	133.28	158.77	154.57	175.72
Transportation	212.64	273.84	271.56	308.81	308.69	340.45	339.36
Total Non-Renewable Expenditures	556.99	669.69	677.32	722.19	809.05	814.69	891.56
Transportation Renewable Expenditures	0.14	0.42	0.42	0.64	0.64	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**677.74**	**722.82**	**809.68**	**815.54**	**892.41**

[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 M2BASE.D060801A, M2C7B08.D060801A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A.

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

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Generation by Fuel Type							
Electric Generators[1]							
Coal	1831	2106	2002	2245	1148	2315	1001
Petroleum	94	43	21	28	10	25	12
Natural Gas[2]	359	583	593	825	1421	1495	1924
Nuclear Power	730	740	740	725	744	613	696
Pumped Storage	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	429	397	515	400	543
Total	**3369**	**3844**	**3783**	**4219**	**3837**	**4847**	**4177**
Non-Utility Generation for Own Use	16	17	21	17	20	17	19
Distributed Generation	0	0	0	1	1	5	1
Cogenerators[4]							
Coal	47	53	52	52	45	52	40
Petroleum	9	10	10	10	10	10	11
Natural Gas	207	237	243	261	331	318	668
Other Gaseous Fuels[5]	4	6	6	7	7	8	9
Renewable Sources[3]	31	34	34	39	39	48	48
Other[6]	5	5	5	5	5	6	6
Total	**303**	**345**	**350**	**373**	**437**	**441**	**781**
Other End-Use Generators[7]	5	5	5	5	5	5	5
Sales to Utilities	151	172	170	180	185	208	290
Generation for Own Use	156	178	185	198	257	238	496
Net Imports[8]	**33**	**57**	**57**	**35**	**49**	**23**	**35**
Electricity Sales by Sector							
Residential	1145	1339	1316	1452	1323	1698	1542
Commercial	1073	1288	1270	1439	1322	1646	1455
Industrial	1058	1142	1122	1222	1124	1395	1158
Transportation	17	26	26	35	34	49	48
Total	**3294**	**3794**	**3733**	**4147**	**3803**	**4788**	**4204**
End-Use Prices (1999 cents per kwh)[9]							
Residential	8.0	7.6	8.0	7.6	10.3	7.7	9.9
Commercial	7.3	6.9	7.5	6.4	9.4	6.5	9.1
Industrial	4.4	4.4	4.7	4.1	6.5	4.2	6.3
Transportation	5.3	5.0	5.2	4.6	6.2	4.5	5.7
All Sectors Average	**6.6**	**6.4**	**6.8**	**6.1**	**8.8**	**6.2**	**8.6**
Prices by Service Category[9] **(1999 cents per kwh)**							
Generation	4.1	3.8	4.2	3.5	6.0	3.6	5.9
Transmission	0.6	0.6	0.6	0.7	0.8	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.1	2.0	2.0
Emissions (million short tons)							
Sulfur Dioxide	13.71	10.38	10.39	9.70	8.20	8.95	7.34
Nitrogen Oxide	5.45	4.30	4.01	4.34	2.44	4.49	2.17

[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 M2BASE.D060801A, M2C7B08.D060801A.

Table C5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections 2005 Reference	2005 CO_2 1990-7% 2008	2010 Reference	2010 CO_2 1990-7% 2008	2020 Reference	2020 CO_2 1990-7% 2008
Electric Generators[2]							
Capability							
Coal Steam	305.1	303.9	302.8	318.6	267.2	318.5	218.4
Other Fossil Steam[3]	137.4	127.8	119.3	119.2	102.7	116.9	92.3
Combined Cycle	21.0	53.2	78.4	107.8	196.3	202.2	268.0
Combustion Turbine/Diesel	74.3	123.1	118.2	147.2	121.5	199.5	134.2
Nuclear Power	97.4	97.5	97.5	94.8	97.5	76.3	90.1
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	88.8	94.8	100.0	98.0	109.1	99.5	117.7
Distributed Generation[5]	0.0	0.7	0.9	2.5	1.4	11.5	3.0
Total	**743.4**	**820.4**	**836.6**	**907.8**	**915.4**	**1044.2**	**943.4**
Cumulative Planned Additions[6]							
Coal Steam	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
Combined Cycle	0.0	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
Nuclear Power	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
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	0.0	5.1	5.1	6.7	6.7	8.1	8.1
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**32.0**	**32.0**	**33.7**	**33.7**	**35.3**	**35.3**
Cumulative Unplanned Additions[6]							
Coal Steam	0.0	1.1	0.0	18.9	0.0	20.5	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	19.4	44.6	74.2	162.7	168.6	234.7
Combustion Turbine/Diesel	0.0	38.9	35.4	64.7	40.8	117.2	53.5
Nuclear Power	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
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	5.7	2.0	13.1	2.0	20.2
Distributed Generation[5]	0.0	0.7	0.9	2.5	1.4	11.5	3.0
Total	**0.0**	**60.6**	**86.7**	**162.2**	**218.0**	**319.8**	**311.5**
Cumulative Total Additions	**0.0**	**92.6**	**118.7**	**195.9**	**251.7**	**355.1**	**346.8**
Cumulative Retirements[7]							
Coal Steam	0.0	2.3	2.3	5.4	37.9	7.2	86.7
Other Fossil Steam[3]	0.0	9.9	18.3	18.4	34.9	20.7	45.4
Combined Cycle	0.0	0.0	0.0	0.2	0.2	0.2	0.5
Combustion Turbine/Diesel	0.0	4.4	5.7	6.0	7.7	6.3	7.8
Nuclear Power	0.0	0.0	0.0	2.6	0.0	21.2	7.4
Pumped Storage	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
Renewable Sources	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**16.7**	**26.5**	**32.8**	**80.9**	**55.6**	**148.0**
Cogenerators[8]							
Capability							
Coal	8.4	8.9	8.9	8.6	7.4	8.6	6.7
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	3.0
Natural Gas	34.6	39.9	40.9	43.3	53.0	51.4	101.3
Other Gaseous Fuels	0.2	0.8	0.8	0.9	0.9	1.1	1.2
Renewable Sources[4]	5.4	5.9	5.9	6.8	6.8	8.2	8.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**60.3**	**63.3**	**71.9**	**73.2**	**121.3**
Cumulative Additions[6]	**0.0**	**6.8**	**7.8**	**10.9**	**19.4**	**20.7**	**68.9**

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

Net Summer Capability[1]	1999	Projections 2005 Reference	2005 CO_2 1990-7% 2008	2010 Reference	2010 CO_2 1990-7% 2008	2020 Reference	2020 CO_2 1990-7% 2008
Other End-Use Generators[9]							
Renewable Sources	1.0	1.1	1.1	1.3	1.3	1.3	1.4
Cumulative Additions	0.0	0.1	0.1	0.3	0.3	0.3	0.4

[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 M2BASE.D060801A, M2C7B08.D060801A.

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

Electricity Trade	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	182.2	125.3	125.3	102.9	102.9	0.0	0.0
Gross Domestic Economy Trade	152.0	202.3	162.5	155.5	58.3	147.9	73.8
Gross Domestic Trade	**334.2**	**327.6**	**287.8**	**258.4**	**161.2**	**147.9**	**73.8**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.8	5905.8	4851.2	4851.2	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4413.9	6468.6	5924.3	4510.4	3242.6	4605.1	4015.2
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11830.1**	**9361.6**	**8093.9**	**4605.1**	**4015.2**
International Electricity Trade							
Firm Power Imports From Canada and	27.0	10.7	10.7	5.8	19.1	0.0	12.1
Economy Imports From Canada and Mexico[1]	21.9	63.5	63.5	45.9	45.9	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**74.1**	**74.1**	**51.7**	**65.0**	**30.6**	**42.7**
Firm Power Exports To Canada and Mexico	9.2	9.7	9.7	8.7	8.7	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.0	7.0	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.7**	**16.7**	**16.4**	**16.4**	**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 M2BASE.D060801A, M2C7B08.D060801A.

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

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Production							
Dry Gas Production[1]	18.67	21.40	20.74	23.43	24.83	29.47	30.52
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.69**	**4.67**	**5.00**	**6.56**	**5.82**	**7.88**
Canada	3.29	4.48	4.45	4.72	4.94	5.43	5.72
Mexico	-0.01	-0.18	-0.18	-0.25	0.32	-0.40	0.36
Liquefied Natural Gas	0.10	0.39	0.39	0.53	1.30	0.79	1.80
Total Supply	**22.15**	**26.20**	**25.52**	**28.49**	**31.45**	**35.35**	**38.45**
Consumption by Sector							
Residential	4.75	5.42	5.45	5.46	5.40	6.07	6.08
Commercial	3.06	3.88	3.91	4.06	4.05	4.32	4.96
Industrial[3]	8.31	8.81	8.82	9.48	9.50	10.53	11.23
Electric Generators[4]	3.64	5.43	4.74	6.81	9.71	11.19	12.84
Lease and Plant Fuel[5]	1.23	1.38	1.34	1.50	1.57	1.87	1.91
Pipeline Fuel	0.64	0.81	0.79	0.88	0.93	1.07	1.11
Transportation[6]	0.02	0.05	0.05	0.09	0.09	0.15	0.15
Total	**21.65**	**25.79**	**25.11**	**28.29**	**31.25**	**35.20**	**38.28**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.20**	**0.20**	**0.14**	**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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2C7B08.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A.

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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Source Price							
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.79	2.87	3.36	3.22	3.74
Average Import Price	2.29	2.95	2.92	2.64	2.95	2.72	3.05
Average[2]	**2.11**	**2.96**	**2.81**	**2.82**	**3.27**	**3.13**	**3.59**
Delivered Prices							
Residential	6.69	7.31	7.16	6.91	7.37	6.83	7.30
Commercial	5.49	5.70	5.56	5.82	6.27	5.93	6.38
Industrial[3]	2.87	3.74	3.59	3.59	4.07	3.95	4.44
Electric Generators[4]	2.63	3.50	3.43	3.32	4.13	3.78	4.53
Transportation[5]	7.21	7.48	7.32	7.40	7.88	7.61	8.04
Average[6]	**4.15**	**4.84**	**4.75**	**4.59**	**5.04**	**4.72**	**5.26**
Transmission & Distribution Margins[7]							
Residential	4.58	4.35	4.34	4.08	4.10	3.70	3.71
Commercial	3.37	2.74	2.74	2.99	3.00	2.81	2.79
Industrial[3]	0.76	0.78	0.77	0.77	0.80	0.82	0.85
Electric Generators[4]	0.52	0.54	0.62	0.49	0.86	0.65	0.93
Transportation[5]	5.10	4.51	4.51	4.58	4.61	4.48	4.45
Average[6]	**2.04**	**1.88**	**1.94**	**1.76**	**1.77**	**1.59**	**1.67**
Transmission & Distribution Revenue (billion 1999 dollars)							
Residential	21.77	23.57	23.68	22.30	22.13	22.48	22.56
Commercial	10.32	10.63	10.72	12.16	12.15	12.12	13.81
Industrial[3]	6.28	6.86	6.83	7.26	7.64	8.65	9.56
Electric Generators[4]	1.88	2.94	2.94	3.36	8.34	7.24	11.99
Transportation[5]	0.08	0.24	0.24	0.41	0.40	0.68	0.66
Total	**40.32**	**44.25**	**44.41**	**45.49**	**50.67**	**51.18**	**58.58**

[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 M2BASE.D060801A, M2C7B08.D060801A.

Table C9. Oil and Gas Supply

Production and Supply	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Crude Oil							
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**21.43**	**20.57**	**20.73**	**20.82**	**21.47**	**21.38**
Production (million barrels per day)[2]							
U.S. Total	**5.88**	**5.66**	**5.68**	**5.32**	**5.28**	**5.25**	**5.34**
Lower 48 Onshore	3.27	2.81	2.81	2.52	2.51	2.75	2.81
Conventional	2.59	2.18	2.18	1.81	1.82	1.98	2.05
Enhanced Oil Recovery	0.68	0.63	0.63	0.70	0.69	0.76	0.76
Lower 48 Offshore	1.56	2.06	2.08	2.16	2.13	1.87	1.89
Alaska	1.05	0.79	0.79	0.65	0.65	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.75**	**15.75**	**14.55**	**14.50**	**14.11**	**14.31**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.79**	**2.87**	**3.36**	**3.22**	**3.74**
Production (trillion cubic feet)[3]							
U.S. Total	**18.67**	**21.40**	**20.74**	**23.43**	**24.83**	**29.47**	**30.52**
Lower 48 Onshore	12.83	14.46	13.91	16.71	17.59	21.31	22.32
Associated-Dissolved[4]	1.80	1.51	1.51	1.32	1.33	1.39	1.43
Non-Associated	11.03	12.95	12.39	15.39	16.26	19.91	20.89
Conventional	6.64	7.67	7.38	7.93	8.50	11.14	11.29
Unconventional	4.39	5.27	5.01	7.45	7.76	8.78	9.60
Lower 48 Offshore	5.43	6.47	6.37	6.22	6.75	7.59	7.64
Associated-Dissolved[4]	0.93	1.06	1.06	1.09	1.09	1.04	1.04
Non-Associated	4.50	5.41	5.31	5.13	5.66	6.56	6.60
Alaska	0.42	0.47	0.46	0.50	0.50	0.57	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**167.88**	**169.86**	**185.55**	**185.18**	**200.71**	**203.89**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.93**	**28.87**	**27.88**	**29.86**	**33.37**	**39.36**	**44.17**

[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 M2BASE.D060801A, M2C7B08.D060801A.

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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Production[1]							
Appalachia	433	426	412	421	285	396	238
Interior	185	182	169	180	125	161	109
West	486	624	591	694	305	783	294
East of the Mississippi	559	561	537	557	380	524	324
West of the Mississippi	544	672	636	738	335	817	317
Total	**1103**	**1233**	**1173**	**1295**	**715**	**1340**	**641**
Net Imports							
Imports	9	16	12	17	9	20	9
Exports	58	60	60	58	57	56	58
Total	**-49**	**-44**	**-48**	**-40**	**-48**	**-36**	**-49**
Total Supply[2]	**1054**	**1189**	**1125**	**1254**	**667**	**1304**	**592**
Consumption by Sector							
Residential and Commercial	5	5	5	5	5	5	5
Industrial[3]	79	82	82	83	81	86	84
Coke Plants	28	25	25	23	23	19	19
Electric Generators[4]	921	1077	1013	1145	559	1196	491
Total	**1032**	**1189**	**1125**	**1256**	**668**	**1306**	**599**
Discrepancy and Stock Change[5]	**21**	**-1**	**-0**	**-2**	**-1**	**-2**	**-7**
Average Minemouth Price							
(1999 dollars per short ton)	17.17	15.05	14.74	14.08	14.22	12.87	12.77
(1999 dollars per million Btu)	0.82	0.73	0.71	0.69	0.67	0.64	0.61
Delivered Prices (1999 dollars per short ton)[6]							
Industrial	31.39	29.67	29.49	28.61	26.50	26.50	23.68
Coke Plants	44.28	42.39	42.43	41.36	41.48	38.52	38.61
Electric Generators							
(1999 dollars per short ton)	24.73	22.90	21.67	21.28	18.98	19.41	16.92
(1999 dollars per million Btu)	1.21	1.14	1.07	1.06	0.93	0.98	0.84
Average	**25.77**	**23.78**	**22.71**	**22.13**	**20.67**	**20.15**	**18.56**
Exports[7]	37.44	36.39	36.36	35.66	34.66	33.09	31.44

[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 M2BASE.D060801A, M2C7B08.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2C7B08.D060801A.

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

Capacity and Generation	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Electric Generators[1] (excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	78.77	79.26	80.43	79.38	80.90	79.38	80.90
Geothermal[2]	2.87	3.43	7.05	4.93	10.66	4.95	11.11
Municipal Solid Waste[3]	2.61	2.96	3.24	3.42	4.42	3.93	4.95
Wood and Other Biomass[4]	1.57	1.75	1.75	2.12	2.87	2.45	3.98
Solar Thermal	0.33	0.35	0.35	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.21	0.21	0.54	0.54
Wind	2.66	6.92	7.10	7.52	9.65	7.76	15.72
Total	**88.83**	**94.75**	**100.01**	**97.98**	**109.10**	**99.49**	**117.68**
Generation (billion kilowatthours)							
Conventional Hydropower	309.55	301.20	305.12	301.13	306.16	300.07	305.01
Geothermal[2]	13.21	18.34	48.20	30.94	77.91	31.16	81.75
Municipal Solid Waste[3]	18.12	20.68	22.93	23.88	31.66	27.76	35.68
Wood and Other Biomass[4]	9.02	14.94	34.61	21.30	73.34	19.78	74.18
Dedicated Plants	7.73	9.16	9.18	11.36	16.44	13.82	24.09
Cofiring	1.29	5.78	25.43	9.94	56.89	5.95	50.09
Solar Thermal	0.89	0.96	0.96	1.11	1.11	1.37	1.37
Solar Photovoltaic	0.03	0.20	0.20	0.51	0.51	1.36	1.36
Wind	4.61	16.30	16.80	18.16	24.07	18.83	43.92
Total	**355.43**	**372.61**	**428.82**	**397.03**	**514.77**	**400.32**	**543.28**
Cogenerators[5]							
Net Summer Capability							
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.17	5.19	6.06	6.06	7.54	7.55
Total	**5.35**	**5.87**	**5.89**	**6.76**	**6.76**	**8.24**	**8.25**
Generation (billion kilowatthours)							
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04
Biomass	27.08	29.92	30.02	35.01	34.94	43.52	43.48
Total	**31.12**	**33.97**	**34.07**	**39.05**	**38.99**	**47.57**	**47.53**
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
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.10	0.10	0.35	0.35	0.35	0.36
Total	**1.00**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.35**
Generation (billion kilowatthours)							
Conventional Hydropower[7]	4.57	4.44	4.44	4.43	4.43	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.20	0.20	0.75	0.75	0.75	0.78
Total	**4.59**	**4.64**	**4.64**	**5.18**	**5.18**	**5.17**	**5.19**

[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 M2BASE.D060801A, M2C7B08.D060801A.

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

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Marketed Renewable Energy[2]							
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.44	0.43
Commercial	**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
Industrial[3]	**2.15**	**2.42**	**2.41**	**2.64**	**2.63**	**3.08**	**3.08**
Conventional Hydroelectric	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
Biomass	1.97	2.23	2.22	2.46	2.44	2.90	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.22**	**0.22**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.19	0.20	0.21	0.21
Electric Generators[5]	**3.88**	**4.19**	**5.36**	**4.73**	**6.92**	**4.78**	**7.32**
Conventional Hydroelectric	3.19	3.10	3.14	3.10	3.15	3.08	3.14
Geothermal	0.28	0.44	1.34	0.85	2.31	0.85	2.44
Municipal Solid Waste[6]	0.25	0.28	0.31	0.32	0.43	0.38	0.49
Biomass	0.12	0.18	0.38	0.26	0.76	0.25	0.78
Dedicated Plants	0.10	0.11	0.10	0.14	0.17	0.17	0.25
Cofiring	0.02	0.07	0.28	0.12	0.59	0.07	0.52
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.17	0.17	0.19	0.25	0.19	0.45
Total Marketed Renewable Energy	**6.64**	**7.31**	**8.47**	**8.10**	**10.28**	**8.62**	**11.15**
Non-Marketed Renewable Energy[7] Selected Consumption							
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**
Solar Hot Water Heating	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol							
From Corn	0.12	0.19	0.18	0.20	0.20	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.02	0.02	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.22**	**0.22**	**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 M2BASE.D060801A, M2C7B08.D060801A.

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	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Residential							
Petroleum	26.0	26.5	26.5	24.5	24.6	23.2	23.6
Natural Gas	69.5	80.2	80.6	80.8	79.9	89.8	90.0
Coal	1.1	1.2	1.2	1.3	1.3	1.3	1.2
Electricity	193.4	227.1	210.5	242.6	151.6	275.6	163.2
Total	**290.1**	**335.0**	**318.9**	**349.2**	**257.4**	**389.8**	**278.1**
Commercial							
Petroleum	13.7	11.8	11.8	12.0	12.1	12.1	12.4
Natural Gas	45.4	57.4	57.8	60.1	59.8	63.9	73.3
Coal	1.7	1.7	1.7	1.8	1.8	1.9	1.9
Electricity	181.3	218.4	203.1	240.4	151.6	267.1	154.0
Total	**242.1**	**289.4**	**274.5**	**314.3**	**225.4**	**345.0**	**241.6**
Industrial[1]							
Petroleum	104.2	99.2	98.5	105.3	106.2	113.6	115.1
Natural Gas[2]	141.6	148.4	148.0	159.8	161.3	180.3	191.6
Coal	55.9	65.8	65.6	65.6	64.3	65.8	64.5
Electricity	178.8	193.6	179.5	204.1	128.9	226.4	122.6
Total	**480.4**	**507.0**	**491.6**	**534.8**	**460.7**	**586.1**	**493.9**
Transportation							
Petroleum[3]	485.8	556.3	554.3	607.2	602.0	704.2	700.2
Natural Gas[4]	9.5	12.8	12.4	14.4	15.0	18.1	18.7
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.1	5.8	3.9	7.9	5.1
Total[3]	**498.2**	**573.6**	**570.9**	**627.5**	**621.1**	**730.2**	**724.1**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	629.7	693.8	691.1	749.0	744.9	853.1	851.4
Natural Gas	266.0	298.8	298.9	315.1	316.0	352.0	373.6
Coal	58.8	68.8	68.5	68.8	67.4	69.0	67.7
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	643.6	597.2	692.8	436.1	777.0	444.9
Total[3]	**1510.8**	**1705.0**	**1655.8**	**1825.7**	**1564.5**	**2051.2**	**1737.7**
Electric Generators[6]							
Petroleum	20.0	9.4	4.2	5.8	1.8	5.2	2.3
Natural Gas	45.8	79.6	69.6	100.0	142.5	164.1	188.4
Coal	490.5	554.6	523.4	587.0	291.7	607.7	254.2
Total	**556.3**	**643.6**	**597.2**	**692.8**	**436.1**	**777.0**	**444.9**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	649.7	703.1	695.3	754.8	746.8	858.3	853.7
Natural Gas	311.8	378.4	368.5	415.0	458.5	516.2	561.9
Coal	549.3	623.3	592.0	655.8	359.2	676.7	321.9
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1705.0**	**1655.8**	**1825.7**	**1564.5**	**2051.2**	**1737.7**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.7**	**6.1**	**5.2**	**6.3**	**5.3**

[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 M2BASE.D060801A, M2C7B08.D060801A.

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

Impacts	1999	Projections					
		2005		2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Emissions							
Nitrogen Oxide (million tons)	5.45	4.30	4.01	4.34	2.44	4.49	2.17
Sulfur Dioxide (million tons)	13.71	10.38	10.39	9.70	8.20	8.95	7.34
Mercury (tons)	43.60	45.24	42.45	45.60	24.16	45.07	21.09
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	597.24	692.78	436.08	776.99	444.95
Allowance Prices							
Nitrogen Oxide (1999 dollars per ton)	0	4352	455	4391	0	5037	0
Sulfur Dioxide (1999 dollars per ton)	0	190	150	187	0	241	0
Mercury (million 1999 dollars per ton)	0	0	0	0	0	0	0
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	38	0	157	0	151
Retrofits (gigawatts)							
Scrubber [1]	0.0	6.5	0.0	7.1	0.0	14.8	0.0
Combustion	0.0	39.9	38.8	42.1	42.8	46.1	44.6
SCR Post-combustion	0.0	92.8	77.4	92.9	77.4	93.0	77.4
SNCR Post-combustion	**0.0**	**25.2**	**36.3**	**26.3**	**36.4**	**43.4**	**36.7**
Coal Production by Sulfur Category (million tons)							
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	586	642	297	721	286
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	412	464	280	440	235
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	175	188	137	179	120

[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 M2BASE.D060801A, M2C7B08.D060801A.

Appendix D

Tables for Hg Cap Cases

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.01	12.01	11.27	11.25	11.21	11.12	11.19	11.14
Natural Gas Plant Liquids	2.62	3.12	3.11	3.12	3.37	3.46	3.42	4.16	4.25	4.17
Dry Natural Gas	19.16	21.95	21.93	21.93	24.04	24.71	24.38	30.24	30.90	30.35
Coal	23.08	25.45	25.42	25.43	26.55	25.01	26.05	27.16	25.77	26.81
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[1]	6.53	7.13	7.14	7.13	7.90	8.02	7.89	8.42	8.57	8.42
Other[2]	1.65	0.35	0.35	0.35	0.31	0.30	0.54	0.33	0.32	0.33
Total	**73.29**	**77.88**	**77.86**	**77.87**	**81.19**	**80.50**	**81.24**	**87.97**	**87.55**	**87.82**
Imports										
Crude Oil[3]	18.96	21.42	21.42	21.40	22.38	22.43	22.43	25.82	25.78	25.85
Petroleum Products[4]	4.14	6.28	6.25	6.27	8.65	8.50	8.47	10.80	10.73	10.79
Natural Gas	3.63	5.13	5.13	5.13	5.55	5.67	5.60	6.59	6.70	6.63
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**	**33.93**	**33.92**	**33.91**	**37.54**	**37.56**	**37.46**	**44.18**	**44.16**	**44.23**
Exports										
Petroleum[6]	1.98	1.73	1.74	1.74	1.69	1.69	1.71	1.85	1.88	1.86
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	1.51	1.45	1.52	1.45	1.41	1.42	1.41
Total	**3.62**	**3.57**	**3.57**	**3.57**	**3.58**	**3.65**	**3.59**	**3.89**	**3.93**	**3.90**
Discrepancy[7]	**0.69**	**0.43**	**0.41**	**0.42**	**0.04**	**-0.04**	**0.11**	**0.11**	**0.19**	**0.13**
Consumption										
Petroleum Products[8]	38.02	41.34	41.35	41.34	44.44	44.44	44.40	50.45	50.48	50.49
Natural Gas	22.21	26.44	26.41	26.42	29.00	29.77	29.38	36.06	36.80	36.18
Coal	21.42	24.39	24.38	24.38	25.64	24.10	25.19	26.42	24.95	26.07
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[1]	6.54	7.13	7.14	7.14	7.91	8.02	7.90	8.43	8.57	8.43
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**	**107.81**	**107.80**	**107.79**	**115.11**	**114.46**	**115.00**	**128.16**	**127.59**	**128.01**
Net Imports - Petroleum	**21.12**	**25.96**	**25.94**	**25.93**	**29.34**	**29.24**	**29.19**	**34.78**	**34.63**	**34.78**
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	2.96	2.96	2.96	2.87	3.06	2.90	3.22	3.41	3.33
Coal Minemouth Price (dollars per ton)	17.17	15.05	15.11	15.19	14.08	14.83	15.37	12.87	14.52	14.10
Average Electric Price (cents per Kwh)	6.6	6.4	6.4	6.4	6.1	6.4	6.2	6.2	6.4	6.3

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.41	0.41
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.24	1.24
Natural Gas	4.88	5.57	5.57	5.57	5.61	5.57	5.60	6.23	6.19	6.21
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	0.44	0.43	0.43
Electricity	3.91	4.57	4.56	4.56	4.95	4.90	4.93	5.79	5.76	5.78
Delivered Energy	**10.66**	**12.01**	**12.01**	**12.01**	**12.34**	**12.25**	**12.31**	**13.74**	**13.67**	**13.71**
Electricity Related Losses	8.44	9.67	9.66	9.66	10.10	9.87	10.06	10.85	10.69	10.82
Total	**19.10**	**21.68**	**21.67**	**21.67**	**22.44**	**22.13**	**22.37**	**24.59**	**24.36**	**24.52**
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	0.60	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	4.17	4.14	4.17	4.44	4.41	4.42
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	4.39	4.39	4.39	4.91	4.88	4.89	5.62	5.59	5.60
Delivered Energy	**7.55**	**9.13**	**9.13**	**9.13**	**9.85**	**9.78**	**9.83**	**10.83**	**10.78**	**10.80**
Electricity Related Losses	7.91	9.30	9.30	9.30	10.01	9.82	9.98	10.51	10.37	10.49
Total	**15.46**	**18.44**	**18.43**	**18.43**	**19.86**	**19.60**	**19.81**	**21.34**	**21.14**	**21.29**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.22	1.22	1.31	1.31	1.31	1.49	1.50	1.50
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.53	2.52	2.51	2.85	2.86	2.85
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.28	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	4.44	4.45	4.44	4.71	4.72	4.71	5.02	5.03	5.03
Petroleum Subtotal	9.45	9.86	9.87	9.87	10.57	10.57	10.55	11.63	11.64	11.64
Natural Gas[6]	9.80	10.46	10.45	10.45	11.27	11.31	11.34	12.73	12.77	12.74
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	1.81	1.81	1.81	1.83	1.82	1.82	1.87	1.87	1.87
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.58	2.58	2.60	2.60	2.59
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.61	3.90	3.89	3.89	4.17	4.16	4.15	4.76	4.72	4.75
Delivered Energy	**27.56**	**29.23**	**29.23**	**29.23**	**31.24**	**31.27**	**31.27**	**34.80**	**34.81**	**34.80**
Electricity Related Losses	7.80	8.25	8.25	8.25	8.50	8.37	8.47	8.91	8.76	8.88
Total	**35.36**	**37.48**	**37.48**	**37.47**	**39.74**	**39.64**	**39.74**	**43.71**	**43.57**	**43.68**

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Transportation										
Distillate Fuel	5.13	6.28	6.28	6.28	7.00	6.99	6.99	8.22	8.21	8.22
Jet Fuel[8]	3.46	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Motor Gasoline[2]	15.92	17.67	17.67	17.67	18.97	18.97	18.97	21.26	21.26	21.27
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.03	0.03	0.03	0.04	0.05	0.05	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.30	0.30	0.30	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	29.03	29.03	31.68	31.67	31.67	36.73	36.72	36.73
Pipeline Fuel Natural Gas	0.66	0.83	0.83	0.83	0.91	0.93	0.92	1.10	1.12	1.10
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.15	0.16
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	0.01	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**	**30.03**	**30.03**	**30.03**	**32.83**	**32.85**	**32.84**	**38.20**	**38.21**	**38.20**
Electricity Related Losses	0.13	0.19	0.19	0.19	0.24	0.24	0.24	0.31	0.31	0.31
Total	**26.41**	**30.22**	**30.22**	**30.22**	**33.07**	**33.09**	**33.08**	**38.51**	**38.51**	**38.51**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.74	8.74	9.49	9.48	9.48	10.85	10.84	10.85
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.03	3.08	3.08	3.07	3.41	3.42	3.41
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.57	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.24	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	5.00	4.99	5.35	5.36	5.36
Petroleum Subtotal	37.01	40.90	40.91	40.90	44.16	44.16	44.14	50.21	50.22	50.22
Natural Gas[6]	18.50	20.91	20.90	20.90	22.05	22.04	22.12	24.66	24.65	24.63
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	1.95	1.95	1.94	2.00	2.00	1.99
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.71	2.71	2.71	2.71	2.70	2.72	2.72	2.72
Renewable Energy[13]	2.65	2.94	2.94	2.94	3.18	3.18	3.18	3.65	3.64	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.94	12.94	14.15	14.06	14.10	16.34	16.24	16.29
Delivered Energy	**72.05**	**80.41**	**80.40**	**80.40**	**86.27**	**86.15**	**86.24**	**97.57**	**97.47**	**97.51**
Electricity Related Losses	24.29	27.40	27.40	27.40	28.84	28.30	28.75	30.58	30.12	30.50
Total	**96.33**	**107.81**	**107.80**	**107.79**	**115.11**	**114.46**	**115.00**	**128.16**	**127.59**	**128.01**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.06	0.06	0.06	0.05	0.04	0.06	0.05	0.05
Residual Fuel	0.96	0.38	0.38	0.38	0.22	0.22	0.22	0.19	0.21	0.22
Petroleum Subtotal	1.02	0.44	0.44	0.44	0.28	0.27	0.26	0.25	0.26	0.27
Natural Gas	3.71	5.53	5.52	5.52	6.94	7.73	7.26	11.40	12.15	11.55
Steam Coal	18.77	21.68	21.67	21.67	22.93	21.39	22.49	23.70	22.23	23.35
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[15]	3.88	4.19	4.20	4.19	4.73	4.84	4.72	4.78	4.93	4.79
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**	**40.35**	**40.33**	**40.33**	**42.99**	**42.36**	**42.85**	**46.92**	**46.36**	**46.79**

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.80	8.80	9.54	9.53	9.52	10.91	10.90	10.90
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.03	3.08	3.08	3.07	3.41	3.42	3.41
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.57	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.01	1.48	1.48	1.48	1.42	1.42	1.42	1.42	1.45	1.46
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	5.00	4.99	5.35	5.36	5.36
Petroleum Subtotal	38.02	41.34	41.35	41.34	44.44	44.44	44.40	50.45	50.48	50.49
Natural Gas	22.21	26.44	26.41	26.42	29.00	29.77	29.38	36.06	36.80	36.18
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	23.59	23.60	24.88	23.34	24.43	25.70	24.22	25.35
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	24.38	24.38	25.64	24.10	25.19	26.42	24.95	26.07
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[17]	6.54	7.13	7.14	7.14	7.91	8.03	7.90	8.43	8.57	8.43
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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**	**107.81**	**107.80**	**107.79**	**115.11**	**114.46**	**115.00**	**128.16**	**127.59**	**128.01**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.40	80.40	86.27	86.15	86.24	97.57	97.47	97.51
Total Energy Use	96.33	107.81	107.80	107.79	115.11	114.46	115.00	128.16	127.59	128.01
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	10960	10960	10960	12667	12667	12667	16515	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1704.4	1704.4	1825.7	1796.5	1817.6	2051.2	2022.7	2043.3

[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.
Hg = Mercury.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Residential	**13.10**	**13.27**	**13.29**	**13.29**	**13.46**	**13.84**	**13.58**	**13.77**	**14.04**	**13.90**
Primary Energy[1]	6.71	7.49	7.49	7.49	7.18	7.32	7.20	7.08	7.21	7.16
Petroleum Products[2]	7.55	9.20	9.17	9.19	9.37	9.35	9.35	9.47	9.39	9.45
Distillate Fuel	6.27	7.45	7.41	7.43	7.57	7.57	7.57	7.78	7.76	7.77
Liquefied Petroleum Gas	10.36	12.60	12.60	12.60	12.86	12.81	12.78	12.75	12.53	12.68
Natural Gas	6.52	7.11	7.11	7.11	6.72	6.91	6.76	6.65	6.82	6.75
Electricity	23.47	22.16	22.23	22.23	22.30	23.05	22.57	22.44	22.90	22.64
Commercial	**13.18**	**12.70**	**12.72**	**12.72**	**12.25**	**12.72**	**12.41**	**12.69**	**13.03**	**12.86**
Primary Energy[1]	5.22	5.57	5.56	5.56	5.68	5.83	5.71	5.79	5.93	5.87
Petroleum Products[2]	4.99	6.13	6.10	6.12	6.29	6.28	6.28	6.40	6.35	6.38
Distillate Fuel	4.37	5.24	5.20	5.22	5.36	5.36	5.37	5.53	5.51	5.52
Residual Fuel	2.63	3.65	3.64	3.64	3.71	3.71	3.71	3.86	3.86	3.86
Natural Gas[3]	5.34	5.55	5.55	5.55	5.66	5.84	5.70	5.78	5.94	5.88
Electricity	21.45	20.26	20.33	20.31	18.76	19.55	19.04	19.00	19.52	19.24
Industrial[4]	**5.27**	**5.76**	**5.75**	**5.76**	**5.67**	**5.81**	**5.69**	**5.90**	**5.98**	**5.95**
Primary Energy	3.91	4.47	4.46	4.47	4.49	4.55	4.48	4.68	4.70	4.71
Petroleum Products[2]	5.54	6.00	5.98	6.00	6.13	6.09	6.08	6.16	6.03	6.13
Distillate Fuel	4.65	5.40	5.36	5.38	5.56	5.55	5.56	5.73	5.70	5.72
Liquefied Petroleum Gas	8.50	7.74	7.74	7.75	7.88	7.79	7.75	7.76	7.54	7.70
Residual Fuel	2.78	3.38	3.38	3.37	3.44	3.44	3.44	3.59	3.59	3.59
Natural Gas[5]	2.79	3.64	3.64	3.64	3.50	3.67	3.53	3.85	4.03	3.95
Metallurgical Coal	1.65	1.58	1.58	1.59	1.54	1.55	1.55	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.35	1.31	1.27	1.31	1.21	1.20	1.22
Electricity	13.00	12.80	12.82	12.82	12.08	12.72	12.31	12.22	12.71	12.44
Transportation	**8.30**	**9.39**	**9.36**	**9.39**	**9.69**	**9.69**	**9.70**	**9.20**	**9.23**	**9.19**
Primary Energy	8.29	9.38	9.35	9.37	9.68	9.67	9.68	9.18	9.21	9.17
Petroleum Products[2]	8.28	9.37	9.34	9.37	9.67	9.67	9.68	9.18	9.21	9.17
Distillate Fuel[6]	8.22	8.98	8.93	8.96	8.95	8.95	8.97	8.83	8.82	8.83
Jet Fuel[7]	4.70	5.29	5.25	5.28	5.49	5.49	5.51	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.78	10.81	11.31	11.30	11.31	10.60	10.66	10.58
Residual Fuel	2.46	3.11	3.11	3.11	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.07	14.07	14.07	14.01	13.97	13.70	13.51	13.64
Natural Gas[10]	7.02	7.28	7.28	7.28	7.21	7.39	7.24	7.41	7.57	7.50
Ethanol (E85)[11]	14.42	19.21	19.20	19.21	19.16	19.18	19.16	19.36	19.40	19.37
Methanol (M85)[12]	10.38	13.13	13.12	13.13	13.83	13.83	13.83	14.35	14.37	14.35
Electricity	15.59	14.52	14.61	14.60	13.62	14.39	14.03	13.22	13.63	13.39
Average End-Use Energy	**8.49**	**9.17**	**9.16**	**9.17**	**9.22**	**9.37**	**9.26**	**9.21**	**9.32**	**9.26**
Primary Energy	6.31	7.19	7.17	7.19	7.35	7.39	7.35	7.23	7.28	7.25
Electricity	19.41	18.65	18.70	18.69	17.99	18.71	18.25	18.19	18.68	18.41
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.63	1.63	1.59	1.75	1.63	1.88	2.05	1.93
Petroleum Products	2.49	3.61	3.61	3.61	3.90	3.89	3.87	4.17	4.09	4.07
Distillate Fuel	4.04	4.72	4.68	4.70	4.87	4.87	4.88	5.06	5.05	5.06
Residual Fuel	2.40	3.42	3.43	3.43	3.65	3.66	3.66	3.89	3.86	3.83
Natural Gas	2.58	3.44	3.43	3.43	3.26	3.48	3.30	3.71	3.92	3.81
Steam Coal	1.21	1.14	1.14	1.14	1.06	1.09	1.06	0.98	1.01	0.98

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.50	8.53	8.81	8.79	8.80	8.49	8.48	8.47
Distillate Fuel	7.25	8.14	8.09	8.12	8.20	8.20	8.22	8.20	8.19	8.19
Jet Fuel	4.70	5.29	5.25	5.28	5.49	5.49	5.51	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.63	8.64	8.74	8.66	8.63	8.54	8.33	8.48
Motor Gasoline[8]	9.45	10.80	10.78	10.81	11.31	11.30	11.31	10.60	10.66	10.58
Residual Fuel	2.47	3.25	3.25	3.25	3.33	3.34	3.34	3.49	3.49	3.49
Natural Gas	4.05	4.72	4.72	4.71	4.47	4.62	4.49	4.60	4.77	4.70
Coal	1.23	1.16	1.15	1.15	1.08	1.11	1.08	1.00	1.02	1.00
Ethanol (E85)[11]	14.42	19.21	19.20	19.21	19.16	19.18	19.16	19.36	19.40	19.37
Methanol (M85)[12]	10.38	13.13	13.12	13.13	13.83	13.83	13.83	14.35	14.37	14.35
Electricity	19.41	18.65	18.70	18.69	17.99	18.71	18.25	18.19	18.68	18.41
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	153.99	154.00	160.41	163.73	161.38	183.27	185.85	184.53
Commercial	98.42	114.97	115.15	115.12	119.69	123.45	120.92	136.41	139.29	137.81
Industrial	111.66	127.05	126.93	127.04	133.28	136.92	134.03	154.57	157.03	156.19
Transportation	212.64	273.84	272.95	273.72	308.81	308.68	308.96	340.45	341.59	340.19
Total Non-Renewable Expenditures	556.99	669.69	669.02	669.89	722.19	732.78	725.28	814.69	823.76	818.73
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.64	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**669.44**	**670.31**	**722.82**	**733.41**	**725.92**	**815.54**	**824.61**	**819.58**

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	2105	2105	2245	2082	2185	2315	2149	2266
Petroleum	94	43	43	43	28	27	26	25	26	27
Natural Gas[2]	359	583	580	581	825	955	871	1495	1618	1522
Nuclear Power	730	740	740	740	725	725	725	613	613	617
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	374	373	397	400	396	400	407	401
Total	**3369**	**3844**	**3841**	**3841**	**4219**	**4189**	**4203**	**4847**	**4812**	**4832**
Non-Utility Generation for Own Use	16	17	17	17	17	17	17	17	16	16
Distributed Generation	0	0	0	0	1	1	1	5	5	5
Cogenerators[4]										
Coal	47	53	53	53	52	51	51	52	51	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	207	237	237	237	261	263	262	318	333	325
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	8
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**	**345**	**345**	**345**	**373**	**375**	**375**	**441**	**456**	**448**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	172	172	180	179	180	208	211	209
Generation for Own Use	156	178	178	178	198	201	200	238	251	243
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1339	1337	1337	1452	1437	1445	1698	1688	1694
Commercial	1073	1288	1287	1287	1439	1429	1435	1646	1637	1642
Industrial	1058	1142	1142	1141	1222	1219	1218	1395	1384	1391
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3294**	**3794**	**3791**	**3791**	**4147**	**4119**	**4132**	**4788**	**4758**	**4776**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.6	7.6	7.6	7.9	7.7	7.7	7.8	7.7
Commercial	7.3	6.9	6.9	6.9	6.4	6.7	6.5	6.5	6.7	6.6
Industrial	4.4	4.4	4.4	4.4	4.1	4.3	4.2	4.2	4.3	4.2
Transportation	5.3	5.0	5.0	5.0	4.6	4.9	4.8	4.5	4.7	4.6
All Sectors Average	**6.6**	**6.4**	**6.4**	**6.4**	**6.1**	**6.4**	**6.2**	**6.2**	**6.4**	**6.3**
Prices by Service Category [9] (1999 cents per kwh)										
Generation	4.1	3.8	3.8	3.8	3.5	3.7	3.5	3.6	3.8	3.7
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	13.71	10.38	10.39	10.39	9.70	8.78	9.67	8.95	7.23	8.95
Nitrogen Oxide	5.45	4.30	3.44	3.44	4.34	3.30	3.42	4.49	3.45	3.54

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

Table D5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.9	303.9	318.6	305.8	314.6	318.5	304.3	314.3
Other Fossil Steam[3]	137.4	127.8	127.8	127.5	119.2	116.3	118.7	116.9	114.0	116.1
Combined Cycle	21.0	53.2	52.5	52.4	107.8	124.1	109.5	202.2	214.3	204.4
Combustion Turbine/Diesel	74.3	123.1	122.6	124.3	147.2	146.3	149.6	199.5	200.2	199.7
Nuclear Power	97.4	97.5	97.5	97.5	94.8	94.8	94.8	76.3	76.3	76.9
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	94.8	94.8	94.7	98.0	98.6	98.0	99.5	100.1	99.5
Distributed Generation[5]	0.0	0.7	0.7	0.7	2.5	2.8	2.7	11.5	11.4	11.4
Total	**743.4**	**820.4**	**819.2**	**820.6**	**907.8**	**908.3**	**907.6**	**1044.2**	**1040.4**	**1042.1**
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	1.1	1.1	18.9	6.3	14.9	20.5	6.7	16.4
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	19.4	18.7	18.7	74.2	90.5	75.9	168.6	180.7	170.8
Combustion Turbine/Diesel	0.0	38.9	38.6	40.3	64.7	63.9	67.3	117.2	117.9	117.4
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	0.4	0.4	2.0	2.6	2.0	2.0	2.6	2.1
Distributed Generation[5]	0.0	0.7	0.7	0.7	2.5	2.8	2.7	11.5	11.4	11.4
Total	**0.0**	**60.6**	**59.6**	**61.2**	**162.2**	**166.0**	**162.8**	**319.8**	**319.3**	**318.1**
Cumulative Total Additions	**0.0**	**92.6**	**91.6**	**93.2**	**195.9**	**199.7**	**196.5**	**355.1**	**354.6**	**353.4**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	5.6	5.4	7.2	7.5	7.2
Other Fossil Steam[3]	0.0	9.9	9.9	10.1	18.4	21.3	18.9	20.7	23.6	21.5
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2
Combusion Turbine/Diesel	0.0	4.4	4.5	4.5	6.0	6.2	6.2	6.3	6.3	6.3
Nuclear Power	0.0	0.0	0.0	0.0	2.6	2.6	2.6	21.2	21.2	20.6
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**	**16.7**	**16.9**	**17.1**	**32.8**	**36.1**	**33.5**	**55.6**	**58.8**	**55.9**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	8.3	8.5	8.6	8.3	8.5
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	39.9	39.9	39.9	43.3	43.7	43.5	51.4	53.6	52.3
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	8.2	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**59.2**	**59.2**	**63.3**	**63.4**	**63.4**	**73.2**	**75.0**	**73.9**
Cumulative Additions[6]	**0.0**	**6.8**	**6.8**	**6.8**	**10.9**	**11.0**	**11.0**	**20.7**	**22.6**	**21.5**

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

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
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	152.0	202.3	201.2	199.2	155.5	126.3	137.9	147.9	119.1	140.5
Gross Domestic Trade	**334.2**	**327.6**	**326.4**	**324.5**	**258.4**	**229.3**	**240.9**	**147.9**	**119.1**	**140.5**
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)	4413.9	6468.6	6424.1	6378.8	4510.4	3987.5	4157.7	4605.1	3990.0	4518.3
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**12329.9**	**12284.6**	**9361.6**	**8838.8**	**9008.9**	**4605.1**	**3990.0**	**4518.3**
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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Production										
Dry Gas Production[1]	18.67	21.40	21.37	21.38	23.43	24.09	23.76	29.47	30.12	29.58
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**	**4.69**	**4.69**	**4.69**	**5.00**	**5.12**	**5.05**	**5.82**	**5.92**	**5.85**
Canada	3.29	4.48	4.48	4.48	4.72	4.83	4.77	5.43	5.53	5.45
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	0.53	0.79	0.80	0.80
Total Supply	**22.15**	**26.20**	**26.18**	**26.18**	**28.49**	**29.26**	**28.87**	**35.35**	**36.09**	**35.49**
Consumption by Sector										
Residential	4.75	5.42	5.42	5.42	5.46	5.43	5.46	6.07	6.03	6.05
Commercial	3.06	3.88	3.88	3.88	4.06	4.03	4.06	4.32	4.29	4.31
Industrial[3]	8.31	8.81	8.80	8.80	9.48	9.48	9.53	10.53	10.53	10.53
Electric Generators[4]	3.64	5.43	5.41	5.42	6.81	7.59	7.13	11.19	11.92	11.33
Lease and Plant Fuel[5]	1.23	1.38	1.38	1.38	1.50	1.53	1.52	1.87	1.90	1.88
Pipeline Fuel	0.64	0.81	0.81	0.81	0.88	0.90	0.89	1.07	1.09	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	**21.65**	**25.79**	**25.76**	**25.77**	**28.29**	**29.05**	**28.66**	**35.20**	**35.93**	**35.32**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.41**	**0.20**	**0.21**	**0.21**	**0.14**	**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.
Hg = Mercury.
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, M2M9008.D060801A, M2M6008.D060801A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.96	2.96	2.87	3.06	2.90	3.22	3.41	3.33
Average Import Price	2.29	2.95	2.95	2.95	2.64	2.73	2.66	2.72	2.81	2.75
Average[2]	**2.11**	**2.96**	**2.96**	**2.96**	**2.82**	**2.99**	**2.86**	**3.13**	**3.30**	**3.23**
Delivered Prices										
Residential	6.69	7.31	7.30	7.30	6.91	7.09	6.94	6.83	7.01	6.93
Commercial	5.49	5.70	5.70	5.70	5.82	6.00	5.85	5.93	6.10	6.03
Industrial[3]	2.87	3.74	3.74	3.74	3.59	3.77	3.63	3.95	4.13	4.06
Electric Generators[4]	2.63	3.50	3.50	3.49	3.32	3.55	3.37	3.78	3.99	3.88
Transportation[5]	7.21	7.48	7.47	7.47	7.40	7.59	7.44	7.61	7.78	7.70
Average[6]	**4.15**	**4.84**	**4.84**	**4.84**	**4.59**	**4.74**	**4.61**	**4.72**	**4.89**	**4.82**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.34	4.08	4.10	4.08	3.70	3.71	3.71
Commercial	3.37	2.74	2.74	2.74	2.99	3.00	2.99	2.81	2.81	2.81
Industrial[3]	0.76	0.78	0.78	0.78	0.77	0.78	0.77	0.82	0.84	0.83
Electric Generators[4]	0.52	0.54	0.54	0.53	0.49	0.55	0.51	0.65	0.69	0.66
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.59	4.58	4.48	4.48	4.48
Average[6]	**2.04**	**1.88**	**1.88**	**1.88**	**1.76**	**1.75**	**1.75**	**1.59**	**1.59**	**1.60**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.57	23.57	22.30	22.24	22.28	22.48	22.35	22.43
Commercial	10.32	10.63	10.63	10.63	12.16	12.10	12.14	12.12	12.05	12.09
Industrial[3]	6.28	6.86	6.85	6.85	7.26	7.39	7.30	8.65	8.81	8.75
Electric Generators[4]	1.88	2.94	2.91	2.90	3.36	4.21	3.62	7.24	8.28	7.45
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.41	0.41	0.68	0.67	0.68
Total	**40.32**	**44.25**	**44.21**	**44.19**	**45.49**	**46.34**	**45.75**	**51.18**	**52.16**	**51.40**

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

Table D9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per barrel)	16.49	21.43	21.38	20.46	20.73	20.78	20.77	21.47	21.49	21.49
Production (million barrels per day)[2]										
U.S. Total	5.88	5.66	5.67	5.67	5.32	5.31	5.30	5.25	5.29	5.26
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.52	2.51	2.75	2.77	2.76
Conventional	2.59	2.18	2.18	2.18	1.81	1.82	1.81	1.98	2.00	1.99
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.70	0.70	0.76	0.77	0.77
Lower 48 Offshore	1.56	2.06	2.07	2.07	2.16	2.15	2.14	1.87	1.87	1.86
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	15.75	15.74	15.74	14.55	14.57	14.49	14.11	14.20	14.13
Natural Gas										
Lower 48 Average Wellhead Price[3]										
(1999 dollars per thousand cubic feet)	2.08	2.96	2.96	2.96	2.87	3.06	2.90	3.22	3.41	3.33
Production (trillion cubic feet)[3]										
U.S. Total	18.67	21.40	21.37	21.38	23.43	24.09	23.76	29.47	30.12	29.58
Lower 48 Onshore	12.83	14.46	14.44	14.45	16.71	17.12	17.00	21.31	21.90	21.37
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.33	1.32	1.39	1.40	1.40
Non-Associated	11.03	12.95	12.93	12.93	15.39	15.79	15.68	19.91	20.50	19.97
Conventional	6.64	7.67	7.66	7.66	7.93	8.18	8.17	11.14	11.29	11.04
Unconventional	4.39	5.27	5.26	5.27	7.45	7.62	7.50	8.78	9.20	8.93
Lower 48 Offshore	5.43	6.47	6.47	6.46	6.22	6.46	6.26	7.59	7.65	7.64
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	5.41	5.40	5.40	5.13	5.37	5.17	6.56	6.61	6.60
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	167.88	167.94	167.94	185.55	185.56	184.38	200.71	198.75	200.05
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	28.87	28.99	28.98	29.86	31.21	30.09	39.36	41.15	40.80

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Production[1]										
Appalachia	433	426	431	431	421	356	422	396	368	395
Interior	185	182	184	184	180	180	196	161	174	189
West	486	624	615	614	694	665	621	783	687	705
East of the Mississippi	559	561	567	567	557	513	594	524	535	569
West of the Mississippi	544	672	662	661	738	687	644	817	694	720
Total	**1103**	**1233**	**1229**	**1229**	**1295**	**1201**	**1238**	**1340**	**1229**	**1289**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	60	57	56	57	56
Total	**-49**	**-44**	**-44**	**-44**	**-40**	**-43**	**-40**	**-36**	**-37**	**-37**
Total Supply[2]	**1054**	**1189**	**1185**	**1185**	**1254**	**1158**	**1198**	**1304**	**1192**	**1252**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	83	83	86	86	86
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1074	1073	1145	1051	1091	1196	1080	1144
Total	**1032**	**1189**	**1187**	**1186**	**1256**	**1163**	**1202**	**1306**	**1190**	**1254**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-2**	**-5**	**-4**	**-2**	**2**	**-2**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	15.11	15.19	14.08	14.83	15.37	12.87	14.52	14.10
(1999 dollars per million Btu)	0.82	0.73	0.73	0.73	0.69	0.71	0.73	0.64	0.69	0.68
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.64	29.68	28.61	27.82	28.75	26.50	26.12	26.59
Coke Plants	44.28	42.39	42.39	42.53	41.36	41.56	41.51	38.52	38.57	38.70
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	22.93	22.92	21.28	22.28	21.85	19.41	20.72	20.02
(1999 dollars per million Btu)	1.21	1.14	1.14	1.14	1.06	1.09	1.06	0.98	1.01	0.98
Average	**25.77**	**23.78**	**23.81**	**23.81**	**22.13**	**23.06**	**22.70**	**20.15**	**21.39**	**20.75**
Exports[7]	37.44	36.39	36.36	36.48	35.66	34.95	35.63	33.09	32.96	33.10

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
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	3.43	3.43	3.43	4.93	5.38	4.95	4.95	5.40	4.97
Municipal Solid Waste[3]	2.61	2.96	2.96	2.96	3.42	3.58	3.42	3.93	4.09	3.93
Wood and Other Biomass[4]	1.57	1.75	1.75	1.75	2.12	2.12	2.12	2.45	2.45	2.45
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	7.76	7.77	7.76
Total	**88.83**	**94.75**	**94.76**	**94.75**	**97.98**	**98.58**	**97.99**	**99.49**	**100.10**	**99.52**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.20	301.20	301.13	301.12	301.13	300.07	300.06	300.07
Geothermal[2]	13.21	18.34	18.35	18.27	30.94	34.61	31.08	31.16	34.82	31.32
Municipal Solid Waste[3]	18.12	20.68	20.68	20.68	23.88	25.14	23.88	27.76	29.02	27.76
Wood and Other Biomass[4]	9.02	14.94	15.85	15.63	21.30	19.57	20.01	19.78	21.25	19.93
Dedicated Plants	7.73	9.16	9.16	9.16	11.36	11.38	11.37	13.82	13.84	13.83
Cofiring	1.29	5.78	6.69	6.47	9.94	8.19	8.64	5.95	7.41	6.10
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	18.83	18.85	18.84
Total	**355.43**	**372.61**	**373.53**	**373.24**	**397.03**	**400.22**	**395.88**	**400.32**	**406.73**	**400.64**
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	5.17	5.17	5.17	6.06	6.06	6.06	7.54	7.54	7.54
Total	**5.35**	**5.87**	**5.87**	**5.87**	**6.76**	**6.76**	**6.76**	**8.24**	**8.24**	**8.24**
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	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.12**	**33.97**	**33.97**	**33.97**	**39.05**	**39.05**	**39.05**	**47.57**	**47.57**	**47.57**
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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	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**	**2.42**	**2.42**	**2.42**	**2.64**	**2.64**	**2.64**	**3.08**	**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	2.23	2.23	2.23	2.46	2.46	2.46	2.90	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.21**	**0.22**	**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	0.20	0.21	0.20	0.21
Electric Generators[5]	**3.88**	**4.19**	**4.20**	**4.19**	**4.73**	**4.84**	**4.72**	**4.78**	**4.93**	**4.79**
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	0.44	0.44	0.44	0.85	0.96	0.85	0.85	0.97	0.86
Municipal Solid Waste[6]	0.25	0.28	0.28	0.28	0.32	0.34	0.32	0.38	0.39	0.38
Biomass	0.12	0.18	0.19	0.19	0.26	0.24	0.24	0.25	0.26	0.25
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.14	0.14	0.17	0.17	0.17
Cofiring	0.02	0.07	0.08	0.08	0.12	0.10	0.10	0.07	0.09	0.08
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**	**7.31**	**7.32**	**7.31**	**8.10**	**8.21**	**8.09**	**8.62**	**8.77**	**8.63**
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	0.20	0.19	0.20	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**	**0.22**	**0.21**	**0.22**	**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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.5	23.2	23.4	23.3
Natural Gas	69.5	80.2	80.2	80.2	80.8	80.3	80.7	89.8	89.2	89.4
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	227.1	226.8	226.8	242.6	231.6	239.4	275.6	265.5	272.8
Total	**290.1**	**335.0**	**334.7**	**334.7**	**349.2**	**337.7**	**345.9**	**389.8**	**379.3**	**386.8**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.1	12.0	12.1	12.1	12.1
Natural Gas	45.4	57.4	57.4	57.4	60.1	59.6	60.0	63.9	63.5	63.7
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	218.2	218.3	240.4	230.3	237.6	267.1	257.4	264.5
Total	**242.1**	**289.4**	**289.2**	**289.2**	**314.3**	**303.7**	**311.5**	**345.0**	**335.0**	**342.2**
Industrial[1]										
Petroleum	104.2	99.2	99.4	99.3	105.3	105.3	104.9	113.6	113.8	113.7
Natural Gas[2]	141.6	148.4	148.2	148.2	159.8	160.4	160.8	180.3	181.2	180.7
Coal	55.9	65.8	65.8	65.8	65.6	65.5	65.5	65.8	65.8	65.8
Electricity	178.8	193.6	193.6	193.6	204.1	196.3	201.7	226.4	217.6	224.0
Total	**480.4**	**507.0**	**507.0**	**506.9**	**534.8**	**527.6**	**532.8**	**586.1**	**578.5**	**584.2**
Transportation										
Petroleum[3]	485.8	556.3	556.3	556.3	607.2	607.2	607.0	704.2	703.9	704.1
Natural Gas[4]	9.5	12.8	12.8	12.8	14.4	14.7	14.5	18.1	18.4	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	4.4	4.4	5.8	5.6	5.7	7.9	7.6	7.8
Total[3]	**498.2**	**573.6**	**573.6**	**573.5**	**627.5**	**627.5**	**627.4**	**730.2**	**730.0**	**730.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	694.0	693.9	749.0	749.1	748.4	853.1	853.3	853.2
Natural Gas	266.0	298.8	298.7	298.7	315.1	314.9	316.0	352.0	352.2	352.0
Coal	58.8	68.8	68.7	68.7	68.8	68.7	68.6	69.0	69.0	69.0
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	643.6	643.0	643.0	692.8	663.8	684.4	777.0	748.1	769.1
Total[3]	**1510.8**	**1705.0**	**1704.4**	**1704.4**	**1825.7**	**1796.5**	**1817.6**	**2051.2**	**2022.7**	**2043.3**
Electric Generators[6]										
Petroleum	20.0	9.4	9.3	9.3	5.8	5.8	5.6	5.2	5.5	5.7
Natural Gas	45.8	79.6	79.4	79.5	100.0	111.3	104.6	164.1	175.0	166.3
Coal	490.5	554.6	554.3	554.3	587.0	546.7	574.2	607.7	567.6	597.1
Total	**556.3**	**643.6**	**643.0**	**643.0**	**692.8**	**663.8**	**684.4**	**777.0**	**748.1**	**769.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	703.3	703.1	754.8	754.8	754.0	858.3	858.8	858.9
Natural Gas	311.8	378.4	378.1	378.1	415.0	426.2	420.6	516.2	527.2	518.2
Coal	549.3	623.3	623.0	623.0	655.8	615.4	642.9	676.7	636.7	666.1
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**	**1705.0**	**1704.4**	**1704.4**	**1825.7**	**1796.5**	**1817.6**	**2051.2**	**2022.7**	**2043.3**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.0**	**6.1**	**6.3**	**6.2**	**6.3**

[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.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

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

Impacts	1999	Projections 2005 Reference	2005 Hg 5-Ton	2005 Hg 20-Ton	2010 Reference	2010 Hg 5-Ton	2010 Hg 20-Ton	2020 Reference	2020 Hg 5-Ton	2020 Hg 20-Ton
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.44	3.44	4.34	3.30	3.42	4.49	3.45	3.54
Sulfur Dioxide (million tons)	13.71	10.38	10.39	10.39	9.70	8.78	9.67	8.95	7.23	8.95
Mercury (tons)	43.60	45.24	45.33	44.94	45.60	5.00	20.00	45.07	5.00	20.00
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	642.98	643.02	692.78	663.76	684.38	776.99	748.12	769.12
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	4256	4277	4391	2651	3669	5037	4545	4645
Sulfur Dioxide (1999 dollars per ton)	0	190	189	185	187	0	0	241	0	12
Mercury (million 1999 dollars per ton)	0	0	0	0	0	358	145	0	388	138
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	0
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	7.6	9.8	7.1	17.6	42.7	14.8	51.7	42.7
Combustion	0.0	39.9	39.6	40.9	42.1	42.6	44.8	46.1	48.6	47.7
SCR Post-combustion	0.0	92.8	93.7	92.3	92.9	94.8	92.3	93.0	98.7	99.7
SNCR Post-combustion	0.0	25.2	22.4	25.3	26.3	22.7	25.6	43.4	24.5	29.7
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	586	584	642	653	575	721	656	654
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	456	455	464	383	455	440	390	432
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	187	190	188	164	209	179	183	203

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
Hg = Mercury.
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 M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A.

Appendix E

Tables for RPS Cases

Table E1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.02	12.02	11.27	11.25	11.28	11.12	10.91	11.08
Natural Gas Plant Liquids	2.62	3.12	3.05	3.10	3.37	3.23	3.34	4.16	3.68	3.98
Dry Natural Gas	19.16	21.95	21.45	21.80	24.04	23.03	23.82	30.24	26.77	28.95
Coal	23.08	25.45	25.11	25.40	26.55	25.20	26.10	27.16	24.34	25.92
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.54
Renewable Energy[1]	6.53	7.13	8.89	7.41	7.90	12.46	9.37	8.42	18.11	12.72
Other[2]	1.65	0.35	0.35	0.35	0.31	0.39	0.31	0.33	0.35	0.33
Total	**73.29**	**77.88**	**78.76**	**77.97**	**81.19**	**83.29**	**81.96**	**87.97**	**90.70**	**89.53**
Imports										
Crude Oil[3]	18.96	21.42	21.39	21.41	22.38	22.39	22.40	25.82	26.06	25.89
Petroleum Products[4]	4.14	6.28	6.24	6.21	8.65	8.64	8.61	10.80	10.98	10.80
Natural Gas	3.63	5.13	5.04	5.17	5.55	5.40	5.57	6.59	6.14	6.44
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**	**33.93**	**33.79**	**33.90**	**37.54**	**37.39**	**37.53**	**44.18**	**44.14**	**44.09**
Exports										
Petroleum[6]	1.98	1.73	1.74	1.74	1.69	1.71	1.72	1.85	1.83	1.80
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	1.51	1.45	1.45	1.45	1.41	1.41	1.41
Total	**3.62**	**3.57**	**3.57**	**3.57**	**3.58**	**3.59**	**3.61**	**3.89**	**3.87**	**3.84**
Discrepancy[7]	**0.69**	**0.43**	**0.41**	**0.42**	**0.04**	**0.10**	**0.04**	**0.11**	**0.14**	**0.16**
Consumption										
Petroleum Products[8]	38.02	41.34	41.25	41.28	44.44	44.29	44.37	50.45	50.16	50.32
Natural Gas	22.21	26.44	25.85	26.33	29.00	27.84	28.80	36.06	32.17	34.61
Coal	21.42	24.39	24.06	24.35	25.64	24.27	25.18	26.42	23.59	25.18
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.54
Renewable Energy[1]	6.54	7.13	8.90	7.41	7.91	12.47	9.37	8.43	18.11	12.73
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**	**107.81**	**108.57**	**107.88**	**115.11**	**117.00**	**115.84**	**128.16**	**130.82**	**129.62**
Net Imports - Petroleum	**21.12**	**25.96**	**25.90**	**25.88**	**29.34**	**29.33**	**29.28**	**34.78**	**35.21**	**34.90**
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	2.96	2.91	2.95	2.87	2.65	2.81	3.22	2.66	2.95
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.98	15.00	14.08	14.19	14.05	12.87	13.28	12.99
Average Electric Price (cents per Kwh)	6.6	6.4	6.4	6.3	6.1	6.3	6.2	6.2	6.5	6.2

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.39	0.40
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.22	1.23
Natural Gas	4.88	5.57	5.58	5.57	5.61	5.66	5.62	6.23	6.41	6.31
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	0.43	0.42	0.44	0.44	0.44
Electricity	3.91	4.57	4.56	4.56	4.95	4.91	4.94	5.79	5.73	5.79
Delivered Energy	**10.66**	**12.01**	**12.01**	**12.01**	**12.34**	**12.34**	**12.34**	**13.74**	**13.84**	**13.81**
Electricity Related Losses	8.44	9.67	9.95	9.69	10.10	10.78	10.35	10.85	11.88	11.40
Total	**19.10**	**21.68**	**21.96**	**21.70**	**22.44**	**23.12**	**22.69**	**24.59**	**25.73**	**25.20**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.37	0.38	0.37	0.36	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	0.60	0.61	0.60	0.62	0.61	0.62	0.62	0.61	0.61
Natural Gas	3.14	3.99	4.00	3.99	4.17	4.21	4.18	4.44	4.59	4.50
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	4.39	4.39	4.40	4.91	4.89	4.91	5.62	5.57	5.61
Delivered Energy	**7.55**	**9.13**	**9.14**	**9.14**	**9.85**	**9.86**	**9.86**	**10.83**	**10.93**	**10.88**
Electricity Related Losses	7.91	9.30	9.58	9.33	10.01	10.72	10.27	10.51	11.57	11.05
Total	**15.46**	**18.44**	**18.72**	**18.47**	**19.86**	**20.58**	**20.13**	**21.34**	**22.49**	**21.94**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.22	1.22	1.31	1.30	1.30	1.49	1.47	1.48
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.53	2.50	2.52	2.85	2.79	2.83
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.28	0.27	0.27
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	4.44	4.44	4.45	4.71	4.70	4.70	5.02	5.01	5.02
Petroleum Subtotal	9.45	9.86	9.86	9.87	10.57	10.53	10.55	11.63	11.52	11.59
Natural Gas[6]	9.80	10.46	10.43	10.44	11.27	11.30	11.29	12.73	12.89	12.75
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	1.81	1.81	1.81	1.83	1.83	1.83	1.87	1.87	1.87
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.59	2.59	2.60	2.60	2.59
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.61	3.90	3.89	3.90	4.17	4.13	4.16	4.76	4.60	4.71
Delivered Energy	**27.56**	**29.23**	**29.19**	**29.22**	**31.24**	**31.19**	**31.24**	**34.80**	**34.68**	**34.73**
Electricity Related Losses	7.80	8.25	8.49	8.27	8.50	9.06	8.71	8.91	9.54	9.28
Total	**35.36**	**37.48**	**37.69**	**37.49**	**39.74**	**40.25**	**39.95**	**43.71**	**44.22**	**44.01**

Table E2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Transportation										
Distillate Fuel	5.13	6.28	6.27	6.28	7.00	6.98	7.00	8.22	8.18	8.21
Jet Fuel[8]	3.46	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Motor Gasoline[2]	15.92	17.67	17.68	17.67	18.97	18.96	18.97	21.26	21.25	21.26
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	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	0.30	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	29.03	29.03	31.68	31.66	31.67	36.73	36.67	36.71
Pipeline Fuel Natural Gas	0.66	0.83	0.82	0.83	0.91	0.88	0.90	1.10	0.99	1.06
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.16	0.16
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	0.01	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**	**30.03**	**30.01**	**30.03**	**32.83**	**32.79**	**32.82**	**38.20**	**38.04**	**38.14**
Electricity Related Losses	0.13	0.19	0.19	0.19	0.24	0.26	0.25	0.31	0.34	0.33
Total	**26.41**	**30.22**	**30.21**	**30.21**	**33.07**	**33.04**	**33.07**	**38.51**	**38.38**	**38.47**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.73	8.73	9.49	9.46	9.48	10.85	10.77	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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.02	3.03	3.08	3.06	3.07	3.41	3.33	3.38
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.56	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.24	1.23	1.23
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.98	4.99	5.35	5.34	5.35
Petroleum Subtotal	37.01	40.90	40.90	40.90	44.16	44.10	44.14	50.21	50.02	50.14
Natural Gas[6]	18.50	20.91	20.88	20.89	22.05	22.14	22.09	24.66	25.03	24.78
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	1.95	1.95	1.95	2.00	2.00	1.99
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.71	2.71	2.71	2.71	2.71	2.72	2.72	2.71
Renewable Energy[13]	2.65	2.94	2.94	2.94	3.18	3.19	3.18	3.65	3.65	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.92	12.94	14.15	14.05	14.13	16.34	16.06	16.28
Delivered Energy	**72.05**	**80.41**	**80.36**	**80.40**	**86.27**	**86.18**	**86.26**	**97.57**	**97.49**	**97.56**
Electricity Related Losses	24.29	27.40	28.22	27.49	28.84	30.81	29.58	30.58	33.33	32.06
Total	**96.33**	**107.81**	**108.57**	**107.88**	**115.11**	**117.00**	**115.84**	**128.16**	**130.82**	**129.62**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.05	0.06	0.06	0.04	0.04	0.06	0.03	0.04
Residual Fuel	0.96	0.38	0.30	0.31	0.22	0.15	0.19	0.19	0.11	0.14
Petroleum Subtotal	1.02	0.44	0.35	0.37	0.28	0.19	0.23	0.25	0.14	0.18
Natural Gas	3.71	5.53	4.97	5.44	6.94	5.70	6.71	11.40	7.14	9.83
Steam Coal	18.77	21.68	21.35	21.64	22.93	21.56	22.46	23.70	20.87	22.46
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.54
Renewable Energy[15]	3.88	4.19	5.95	4.47	4.73	9.29	6.19	4.78	14.46	9.08
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**	**40.35**	**41.14**	**40.43**	**42.99**	**44.86**	**43.71**	**46.92**	**49.39**	**48.34**

Table E2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.78	8.80	9.54	9.50	9.52	10.91	10.80	10.86
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.02	3.03	3.08	3.06	3.07	3.41	3.33	3.38
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.56	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.01	1.48	1.40	1.41	1.42	1.35	1.38	1.42	1.33	1.38
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.98	4.99	5.35	5.34	5.35
Petroleum Subtotal	38.02	41.34	41.25	41.28	44.44	44.29	44.37	50.45	50.16	50.32
Natural Gas	22.21	26.44	25.85	26.33	29.00	27.84	28.80	36.06	32.17	34.61
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	23.27	23.56	24.88	23.51	24.41	25.70	22.87	24.45
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	24.06	24.35	25.64	24.27	25.18	26.42	23.59	25.18
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.54
Renewable Energy[17]	6.54	7.13	8.90	7.41	7.91	12.47	9.37	8.43	18.12	12.73
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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**	**107.81**	**108.57**	**107.88**	**115.11**	**117.00**	**115.84**	**128.16**	**130.83**	**129.63**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.36	80.40	86.27	86.18	86.26	97.57	97.49	97.56
Total Energy Use	96.33	107.81	108.57	107.88	115.11	117.00	115.84	128.16	130.83	129.63
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	10960	10960	10960	12667	12667	12667	16515	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1686.2	1701.0	1825.7	1770.8	1809.5	2051.2	1916.1	1995.8

[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.
RPS = Renewable Portfolio Standards.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2005 Reference	2005 RPS 20%	2005 RPS 10%	2010 Reference	2010 RPS 20%	2010 RPS 10%	2020 Reference	2020 RPS 20%	2020 RPS 10%
Residential	**13.10**	**13.27**	**13.29**	**13.26**	**13.46**	**13.58**	**13.48**	**13.77**	**13.76**	**13.65**
Primary Energy[1]	6.71	7.49	7.45	7.47	7.18	7.03	7.13	7.08	6.64	6.87
Petroleum Products[2]	7.55	9.20	9.17	9.16	9.37	9.36	9.36	9.47	9.56	9.48
Distillate Fuel	6.27	7.45	7.40	7.38	7.57	7.58	7.57	7.78	7.76	7.76
Liquefied Petroleum Gas	10.36	12.60	12.59	12.60	12.86	12.83	12.83	12.75	13.14	12.85
Natural Gas	6.52	7.11	7.06	7.10	6.72	6.54	6.67	6.65	6.13	6.41
Electricity	23.47	22.16	22.30	22.17	22.30	22.92	22.42	22.44	23.31	22.54
Commercial	**13.18**	**12.70**	**12.73**	**12.65**	**12.25**	**12.43**	**12.25**	**12.69**	**12.72**	**12.54**
Primary Energy[1]	5.22	5.57	5.52	5.55	5.68	5.53	5.64	5.79	5.34	5.58
Petroleum Products[2]	4.99	6.13	6.10	6.08	6.29	6.29	6.29	6.40	6.46	6.40
Distillate Fuel	4.37	5.24	5.19	5.17	5.36	5.37	5.36	5.53	5.52	5.51
Residual Fuel	2.63	3.65	3.63	3.63	3.71	3.70	3.70	3.86	3.84	3.85
Natural Gas[3]	5.34	5.55	5.50	5.54	5.66	5.49	5.61	5.78	5.26	5.54
Electricity	21.45	20.26	20.40	20.17	18.76	19.34	18.82	19.00	19.69	18.96
Industrial[4]	**5.27**	**5.76**	**5.74**	**5.73**	**5.67**	**5.64**	**5.64**	**5.90**	**5.76**	**5.79**
Primary Energy	3.91	4.47	4.44	4.45	4.49	4.39	4.46	4.68	4.46	4.57
Petroleum Products[2]	5.54	6.00	5.97	5.97	6.13	6.10	6.10	6.16	6.24	6.17
Distillate Fuel	4.65	5.40	5.35	5.34	5.56	5.56	5.55	5.73	5.71	5.70
Liquefied Petroleum Gas	8.50	7.74	7.73	7.74	7.88	7.80	7.82	7.76	8.08	7.84
Residual Fuel	2.78	3.38	3.37	3.37	3.44	3.42	3.43	3.59	3.58	3.58
Natural Gas[5]	2.79	3.64	3.59	3.63	3.50	3.31	3.44	3.85	3.31	3.60
Metallurgical Coal	1.65	1.58	1.58	1.58	1.54	1.55	1.55	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.35	1.31	1.30	1.30	1.21	1.20	1.21
Electricity	13.00	12.80	12.88	12.73	12.08	12.55	12.15	12.22	12.87	12.23
Transportation	**8.30**	**9.39**	**9.36**	**9.33**	**9.69**	**9.71**	**9.71**	**9.20**	**9.21**	**9.19**
Primary Energy	8.29	9.38	9.34	9.31	9.68	9.69	9.69	9.18	9.19	9.17
Petroleum Products[2]	8.28	9.37	9.34	9.31	9.67	9.69	9.69	9.18	9.18	9.17
Distillate Fuel[6]	8.22	8.98	8.92	8.90	8.95	8.95	8.95	8.83	8.83	8.82
Jet Fuel[7]	4.70	5.29	5.25	5.23	5.49	5.49	5.49	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.78	10.74	11.31	11.33	11.33	10.60	10.61	10.58
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	14.04	14.05	14.07	14.02	14.03	13.70	14.02	13.80
Natural Gas[10]	7.02	7.28	7.22	7.26	7.21	7.02	7.15	7.41	6.88	7.17
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.20	19.21	19.36	19.30	19.33
Methanol (M85)[12]	10.38	13.13	13.09	13.11	13.83	13.84	13.84	14.35	14.36	14.35
Electricity	15.59	14.52	14.67	14.49	13.62	14.20	13.80	13.22	14.05	13.33
Average End-Use Energy	**8.49**	**9.17**	**9.15**	**9.12**	**9.22**	**9.25**	**9.22**	**9.21**	**9.18**	**9.14**
Primary Energy	6.31	7.19	7.16	7.15	7.35	7.29	7.33	7.23	7.07	7.15
Electricity	19.41	18.65	18.77	18.60	17.99	18.55	18.07	18.19	18.97	18.23
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.58	1.62	1.59	1.49	1.57	1.88	1.52	1.74
Petroleum Products	2.49	3.61	3.63	3.64	3.90	4.01	3.91	4.17	4.42	4.24
Distillate Fuel	4.04	4.72	4.69	4.66	4.87	4.88	4.88	5.06	5.10	5.06
Residual Fuel	2.40	3.42	3.44	3.44	3.65	3.78	3.69	3.89	4.23	4.04
Natural Gas	2.58	3.44	3.34	3.41	3.26	3.02	3.20	3.71	3.06	3.43
Steam Coal	1.21	1.14	1.13	1.14	1.06	1.07	1.06	0.98	0.97	0.98

Table E3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.51	8.48	8.81	8.82	8.82	8.49	8.53	8.49
Distillate Fuel	7.25	8.14	8.09	8.07	8.20	8.21	8.21	8.20	8.21	8.19
Jet Fuel	4.70	5.29	5.25	5.23	5.49	5.49	5.49	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.62	8.63	8.74	8.68	8.70	8.54	8.87	8.62
Motor Gasoline[8]	9.45	10.80	10.78	10.74	11.31	11.33	11.33	10.60	10.61	10.58
Residual Fuel	2.47	3.25	3.24	3.24	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.05	4.72	4.69	4.71	4.47	4.34	4.43	4.60	4.18	4.40
Coal	1.23	1.16	1.15	1.15	1.08	1.09	1.08	1.00	0.99	1.00
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.20	19.21	19.36	19.30	19.33
Methanol (M85)[12]	10.38	13.13	13.09	13.11	13.83	13.84	13.84	14.35	14.36	14.35
Electricity	19.41	18.65	18.77	18.60	17.99	18.55	18.07	18.19	18.97	18.23
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	154.00	153.69	160.41	161.84	160.56	183.27	184.47	182.54
Commercial	98.42	114.97	115.30	114.53	119.69	121.55	119.76	136.41	137.91	135.39
Industrial	111.66	127.05	126.58	126.37	133.28	132.80	132.78	154.57	151.28	151.74
Transportation	212.64	273.84	272.89	271.90	308.81	309.08	309.20	340.45	340.30	339.91
Total Non-Renewable Expenditures	556.99	669.69	668.77	666.50	722.19	725.27	722.30	814.69	813.96	809.58
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.64	0.64	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**669.19**	**666.92**	**722.82**	**725.91**	**722.93**	**815.54**	**814.81**	**810.43**

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	2076	2104	2245	2105	2199	2315	2039	2195
Petroleum	94	43	35	37	28	20	23	25	14	19
Natural Gas[2]	359	583	522	581	825	651	789	1495	888	1266
Nuclear Power	730	740	740	740	725	725	725	613	613	613
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	466	383	397	687	476	400	1200	735
Total	**3369**	**3844**	**3837**	**3843**	**4219**	**4188**	**4212**	**4847**	**4754**	**4827**
Non-Utility Generation for Own Use	16	17	16	16	17	16	16	17	16	16
Distributed Generation	0	0	0	0	1	1	1	5	4	4
Cogenerators[4]										
Coal	47	53	53	53	52	52	52	52	51	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	207	237	237	237	261	268	261	318	370	331
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	8
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**	**345**	**345**	**345**	**373**	**380**	**374**	**441**	**493**	**453**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	171	171	180	180	180	208	218	210
Generation for Own Use	156	178	178	178	198	205	199	238	280	248
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1339	1335	1338	1452	1440	1449	1698	1678	1696
Commercial	1073	1288	1286	1288	1439	1432	1438	1646	1633	1645
Industrial	1058	1142	1140	1142	1222	1211	1220	1395	1347	1382
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3294**	**3794**	**3787**	**3794**	**4147**	**4117**	**4141**	**4788**	**4707**	**4771**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.6	7.6	7.6	7.8	7.7	7.7	8.0	7.7
Commercial	7.3	6.9	7.0	6.9	6.4	6.6	6.4	6.5	6.7	6.5
Industrial	4.4	4.4	4.4	4.3	4.1	4.3	4.1	4.2	4.4	4.2
Transportation	5.3	5.0	5.0	4.9	4.6	4.8	4.7	4.5	4.8	4.5
All Sectors Average	**6.6**	**6.4**	**6.4**	**6.3**	**6.1**	**6.3**	**6.2**	**6.2**	**6.5**	**6.2**
Prices by Service Category[9] (1999 cents per kwh)										
Generation	4.1	3.8	3.8	3.8	3.5	3.6	3.5	3.6	3.8	3.6
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	13.71	10.38	10.39	10.39	9.70	9.70	9.70	8.95	8.95	8.95
Nitrogen Oxide	5.45	4.30	4.25	4.28	4.34	4.23	4.34	4.49	4.15	4.43

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.6	304.2	318.6	307.9	317.2	318.5	304.8	315.4
Other Fossil Steam[3]	137.4	127.8	125.5	125.3	119.2	115.1	116.4	116.9	108.9	114.0
Combined Cycle	21.0	53.2	50.6	57.8	107.8	84.5	103.5	202.2	126.8	176.6
Combustion Turbine/Diesel	74.3	123.1	127.2	125.6	147.2	150.4	152.0	199.5	191.4	197.5
Nuclear Power	97.4	97.5	97.5	97.5	94.8	94.8	94.8	76.3	76.3	76.3
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	94.8	107.7	95.8	98.0	150.8	103.8	99.5	255.8	152.1
Distributed Generation[5]	0.0	0.7	0.7	0.8	2.5	2.3	2.5	11.5	9.8	10.2
Total	**743.4**	**820.4**	**832.2**	**826.6**	**907.8**	**925.3**	**909.8**	**1044.2**	**1093.7**	**1061.9**
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	0.8	1.4	18.9	8.6	17.6	20.5	8.6	17.6
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	19.4	16.8	24.0	74.2	50.9	69.9	168.6	93.2	143.0
Combustion Turbine/Diesel	0.0	38.9	43.9	42.4	64.7	68.7	70.3	117.2	110.0	115.8
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	13.4	1.5	2.0	54.8	7.8	2.0	158.4	54.6
Distributed Generation[5]	0.0	0.7	0.7	0.8	2.5	2.3	2.5	11.5	9.8	10.2
Total	**0.0**	**60.6**	**75.6**	**70.2**	**162.2**	**185.3**	**168.0**	**319.8**	**380.0**	**341.2**
Cumulative Total Additions	**0.0**	**92.6**	**107.6**	**102.2**	**195.9**	**218.9**	**201.7**	**355.1**	**415.3**	**376.5**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	5.8	5.5	7.2	8.9	7.3
Other Fossil Steam[3]	0.0	9.9	12.1	12.3	18.4	22.5	21.3	20.7	28.7	23.6
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	4.4	5.3	5.3	6.0	6.9	6.7	6.3	7.1	6.8
Nuclear Power	0.0	0.0	0.0	0.0	2.6	2.6	2.6	21.2	21.2	21.2
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**	**16.7**	**19.9**	**20.0**	**32.8**	**38.3**	**36.5**	**55.6**	**66.2**	**59.2**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	8.6	8.6	8.6	8.5	8.6
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	39.9	39.9	39.9	43.3	44.4	43.4	51.4	58.6	53.1
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	8.2	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**59.3**	**59.2**	**63.3**	**64.4**	**63.4**	**73.2**	**80.3**	**74.9**
Cumulative Additions[6]	**0.0**	**6.8**	**6.8**	**6.7**	**10.9**	**11.9**	**11.0**	**20.7**	**27.9**	**22.5**

Table E5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	2005 Reference	2005 RPS 20%	2005 RPS 10%	2010 Reference	2010 RPS 20%	2010 RPS 10%	2020 Reference	2020 RPS 20%	2020 RPS 10%
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	152.0	202.3	199.9	189.8	155.5	174.5	149.8	147.9	219.4	155.5
Gross Domestic Trade	**334.2**	**327.6**	**325.1**	**315.0**	**258.4**	**277.4**	**252.7**	**147.9**	**219.4**	**155.5**
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)	4413.9	6468.6	6549.9	5922.6	4510.4	5179.6	4335.7	4605.1	7165.9	4705.5
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**12455.7**	**11828.4**	**9361.6**	**10030.8**	**9186.9**	**4605.1**	**7165.9**	**4705.5**
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**

Note: 2005, 2010 and 2020 columns are Projections.

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

RPS = Renewable Portfolio Standards.

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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Production										
Dry Gas Production[1]	18.67	21.40	20.90	21.24	23.43	22.45	23.21	29.47	26.09	28.22
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**	**4.69**	**4.61**	**4.74**	**5.00**	**4.86**	**5.02**	**5.82**	**5.38**	**5.67**
Canada	3.29	4.48	4.40	4.52	4.72	4.58	4.74	5.43	5.03	5.29
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	0.52	0.53	0.79	0.75	0.78
Total Supply	**22.15**	**26.20**	**25.63**	**26.09**	**28.49**	**27.36**	**28.29**	**35.35**	**31.52**	**33.94**
Consumption by Sector										
Residential	4.75	5.42	5.43	5.43	5.46	5.51	5.48	6.07	6.24	6.14
Commercial	3.06	3.88	3.89	3.88	4.06	4.10	4.07	4.32	4.47	4.38
Industrial[3]	8.31	8.81	8.80	8.80	9.48	9.55	9.51	10.53	10.85	10.61
Electric Generators[4]	3.64	5.43	4.88	5.34	6.81	5.59	6.59	11.19	7.00	9.65
Lease and Plant Fuel[5]	1.23	1.38	1.35	1.37	1.50	1.45	1.49	1.87	1.70	1.81
Pipeline Fuel	0.64	0.81	0.80	0.81	0.88	0.86	0.88	1.07	0.97	1.04
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.65**	**25.79**	**25.21**	**25.68**	**28.29**	**27.15**	**28.10**	**35.20**	**31.38**	**33.78**
Discrepancy[7]	**0.50**	**0.42**	**0.42**	**0.41**	**0.20**	**0.20**	**0.19**	**0.14**	**0.14**	**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.
RPS = Renewable Portfolio Standards.
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, M2RPS20_X.D070601A, M2RPS20H_X.D070601A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E8. 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	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.91	2.95	2.87	2.65	2.81	3.22	2.66	2.95
Average Import Price	2.29	2.95	2.93	2.96	2.64	2.58	2.65	2.72	2.56	2.68
Average[2]	**2.11**	**2.96**	**2.91**	**2.95**	**2.82**	**2.64**	**2.78**	**3.13**	**2.64**	**2.90**
Delivered Prices										
Residential	6.69	7.31	7.25	7.29	6.91	6.72	6.85	6.83	6.29	6.58
Commercial	5.49	5.70	5.65	5.69	5.82	5.63	5.76	5.93	5.40	5.69
Industrial[3]	2.87	3.74	3.69	3.73	3.59	3.40	3.54	3.95	3.39	3.69
Electric Generators[4]	2.63	3.50	3.41	3.47	3.32	3.08	3.26	3.78	3.12	3.50
Transportation[5]	7.21	7.48	7.41	7.45	7.40	7.21	7.35	7.61	7.06	7.36
Average[6]	**4.15**	**4.84**	**4.81**	**4.83**	**4.59**	**4.45**	**4.54**	**4.72**	**4.29**	**4.51**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.34	4.08	4.08	4.07	3.70	3.65	3.68
Commercial	3.37	2.74	2.74	2.74	2.99	2.99	2.99	2.81	2.76	2.79
Industrial[3]	0.76	0.78	0.78	0.78	0.77	0.76	0.76	0.82	0.75	0.79
Electric Generators[4]	0.52	0.54	0.50	0.52	0.49	0.44	0.48	0.65	0.48	0.59
Transportation[5]	5.10	4.51	4.50	4.51	4.58	4.57	4.57	4.48	4.42	4.46
Average[6]	**2.04**	**1.88**	**1.90**	**1.88**	**1.76**	**1.81**	**1.77**	**1.59**	**1.65**	**1.61**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.61	23.57	22.30	22.47	22.32	22.48	22.77	22.58
Commercial	10.32	10.63	10.66	10.64	12.16	12.27	12.17	12.12	12.34	12.20
Industrial[3]	6.28	6.86	6.86	6.85	7.26	7.26	7.23	8.65	8.17	8.37
Electric Generators[4]	1.88	2.94	2.42	2.79	3.36	2.47	3.18	7.24	3.35	5.72
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.41	0.41	0.68	0.68	0.68
Total	**40.32**	**44.25**	**43.79**	**44.10**	**45.49**	**44.88**	**45.30**	**51.18**	**47.31**	**49.56**

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per barrel)	**16.49**	**21.43**	**20.56**	**22.29**	**20.73**	**20.76**	**20.77**	**21.47**	**21.51**	**21.52**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.66**	**5.68**	**5.68**	**5.32**	**5.31**	**5.33**	**5.25**	**5.15**	**5.23**
Lower 48 Onshore	3.27	2.81	2.81	2.82	2.52	2.51	2.52	2.75	2.68	2.71
Conventional	2.59	2.18	2.18	2.18	1.81	1.80	1.81	1.98	1.93	1.97
Enhanced Oil Recovery	0.68	0.63	0.63	0.64	0.70	0.71	0.71	0.76	0.75	0.74
Lower 48 Offshore	1.56	2.06	2.07	2.07	2.16	2.15	2.16	1.87	1.84	1.88
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**	**15.75**	**15.74**	**15.77**	**14.55**	**14.47**	**14.55**	**14.11**	**13.88**	**14.04**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.91**	**2.95**	**2.87**	**2.65**	**2.81**	**3.22**	**2.66**	**2.95**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.40**	**20.90**	**21.24**	**23.43**	**22.45**	**23.21**	**29.47**	**26.09**	**28.22**
Lower 48 Onshore	12.83	14.46	14.07	14.32	16.71	15.82	16.53	21.31	19.08	20.05
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.32	1.32	1.39	1.37	1.39
Non-Associated	11.03	12.95	12.55	12.80	15.39	14.50	15.21	19.91	17.71	18.66
Conventional	6.64	7.67	7.51	7.63	7.93	7.49	7.91	11.14	10.23	10.43
Unconventional	4.39	5.27	5.04	5.17	7.45	7.00	7.30	8.78	7.48	8.23
Lower 48 Offshore	5.43	6.47	6.37	6.46	6.22	6.12	6.17	7.59	6.44	7.60
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.03	1.04
Non-Associated	4.50	5.41	5.31	5.40	5.13	5.03	5.08	6.56	5.41	6.56
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**	**167.88**	**168.51**	**168.34**	**185.55**	**180.63**	**182.87**	**200.71**	**200.76**	**204.02**
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**	**28.87**	**28.61**	**28.82**	**29.86**	**27.74**	**29.14**	**39.36**	**33.40**	**37.65**

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Production[1]										
Appalachia	433	426	420	425	421	404	412	396	379	383
Interior	185	182	180	181	180	177	180	161	159	163
West	486	624	616	625	694	644	680	783	650	729
East of the Mississippi	559	561	553	558	557	538	549	524	504	511
West of the Mississippi	544	672	664	673	738	687	724	817	685	764
Total	**1103**	**1233**	**1217**	**1231**	**1295**	**1225**	**1273**	**1340**	**1188**	**1275**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	58	58	56	56	56
Total	**-49**	**-44**	**-44**	**-44**	**-40**	**-40**	**-40**	**-36**	**-36**	**-36**
Total Supply[2]	**1054**	**1189**	**1173**	**1187**	**1254**	**1185**	**1233**	**1304**	**1152**	**1239**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	83	83	86	86	85
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1061	1075	1145	1074	1122	1196	1043	1131
Total	**1032**	**1189**	**1174**	**1188**	**1256**	**1186**	**1234**	**1306**	**1153**	**1241**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-2**	**-1**	**-1**	**-2**	**-1**	**-2**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	14.98	15.00	14.08	14.19	14.05	12.87	13.28	12.99
(1999 dollars per million Btu)	0.82	0.73	0.73	0.73	0.69	0.69	0.69	0.64	0.65	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.55	29.64	28.61	28.54	28.56	26.50	26.33	26.45
Coke Plants	44.28	42.39	42.39	42.47	41.36	41.48	41.50	38.52	38.71	38.65
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	22.81	22.86	21.28	21.38	21.24	19.41	19.39	19.38
(1999 dollars per million Btu)	1.21	1.14	1.13	1.14	1.06	1.07	1.06	0.98	0.97	0.98
Average	**25.77**	**23.78**	**23.70**	**23.75**	**22.13**	**22.27**	**22.11**	**20.15**	**20.23**	**20.16**
Exports[7]	37.44	36.39	36.33	36.42	35.66	35.68	35.69	33.09	33.08	33.14

[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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	2005 Reference	2005 RPS 20%	2005 RPS 10%	2010 Reference	2010 RPS 20%	2010 RPS 10%	2020 Reference	2020 RPS 20%	2020 RPS 10%
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	3.43	8.36	4.39	4.93	13.97	8.78	4.95	15.29	10.41
Municipal Solid Waste[3]	2.61	2.96	3.61	3.09	3.42	4.29	3.97	3.93	4.91	4.58
Wood and Other Biomass[4]	1.57	1.75	5.15	1.75	2.12	17.52	2.17	2.45	60.95	17.77
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	10.90	6.92	7.52	35.03	8.87	7.76	94.30	38.94
Total	**88.83**	**94.75**	**107.71**	**95.85**	**97.98**	**150.79**	**103.78**	**99.49**	**255.84**	**152.10**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.21	301.20	301.13	301.13	301.13	300.07	300.07	300.07
Geothermal[2]	13.21	18.34	58.83	26.30	30.94	103.78	62.53	31.16	114.17	76.08
Municipal Solid Waste[3]	18.12	20.68	25.82	21.76	23.88	30.67	28.16	27.76	35.48	32.83
Wood and Other Biomass[4]	9.02	14.94	51.80	16.02	21.30	154.62	60.94	19.78	483.01	207.63
Dedicated Plants	7.73	9.16	31.64	9.16	11.36	114.19	11.78	13.82	403.94	116.13
Cofiring	1.29	5.78	20.16	6.86	9.94	40.42	49.16	5.95	79.08	91.50
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	26.79	16.30	18.16	95.63	22.01	18.83	264.37	115.98
Total	**355.43**	**372.61**	**465.60**	**382.74**	**397.03**	**687.45**	**476.39**	**400.32**	**1199.83**	**735.31**
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	5.17	5.17	5.17	6.06	6.06	6.06	7.54	7.54	7.54
Total	**5.35**	**5.87**	**5.87**	**5.87**	**6.76**	**6.76**	**6.76**	**8.24**	**8.24**	**8.24**
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	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.12**	**33.97**	**33.97**	**33.97**	**39.05**	**39.05**	**39.05**	**47.57**	**47.57**	**47.57**
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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.43**	**0.42**	**0.44**	**0.44**	**0.44**
Wood	0.41	0.42	0.42	0.42	0.42	0.43	0.42	0.44	0.44	0.44
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**	**2.42**	**2.42**	**2.42**	**2.64**	**2.64**	**2.64**	**3.08**	**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	2.23	2.23	2.23	2.46	2.46	2.46	2.90	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.23**	**0.22**	**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	0.20	0.20	0.21	0.20	0.21
Electric Generators[5]	**3.88**	**4.19**	**5.95**	**4.47**	**4.73**	**9.29**	**6.19**	**4.78**	**14.46**	**9.08**
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	0.44	1.69	0.70	0.85	3.29	1.80	0.85	3.68	2.29
Municipal Solid Waste[6]	0.25	0.28	0.35	0.30	0.32	0.42	0.38	0.38	0.48	0.45
Biomass	0.12	0.18	0.53	0.19	0.26	1.48	0.66	0.25	4.47	2.04
Dedicated Plants	0.10	0.11	0.32	0.11	0.14	1.10	0.13	0.17	3.74	1.14
Cofiring	0.02	0.07	0.21	0.08	0.12	0.39	0.53	0.07	0.73	0.90
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	0.28	0.17	0.19	0.98	0.23	0.19	2.72	1.19
Total Marketed Renewable Energy	**6.64**	**7.31**	**9.07**	**7.59**	**8.10**	**12.67**	**9.56**	**8.62**	**18.31**	**12.92**
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	0.20	0.21	0.20	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**	**0.22**	**0.23**	**0.22**	**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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.5	23.2	23.1	23.2
Natural Gas	69.5	80.2	80.4	80.3	80.8	81.5	81.0	89.8	92.3	90.8
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	227.1	220.5	225.6	242.6	223.1	236.7	275.6	228.2	256.3
Total	**290.1**	**335.0**	**328.6**	**333.6**	**349.2**	**330.4**	**343.5**	**389.8**	**344.7**	**371.5**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.0	12.0	12.1	11.8	12.0
Natural Gas	45.4	57.4	57.5	57.4	60.1	60.6	60.2	63.9	66.1	64.8
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	212.3	217.3	240.4	221.9	234.9	267.1	222.1	248.6
Total	**242.1**	**289.4**	**283.4**	**288.3**	**314.3**	**296.4**	**309.0**	**345.0**	**301.9**	**327.3**
Industrial[1]										
Petroleum	104.2	99.2	99.2	99.3	105.3	104.5	105.1	113.6	111.7	112.9
Natural Gas[2]	141.6	148.4	147.9	148.1	159.8	160.2	159.9	180.3	182.4	180.9
Coal	55.9	65.8	65.8	65.8	65.6	65.6	65.7	65.8	65.9	65.7
Electricity	178.8	193.6	188.2	192.6	204.1	187.6	199.3	226.4	183.1	208.8
Total	**480.4**	**507.0**	**501.1**	**505.8**	**534.8**	**518.0**	**530.0**	**586.1**	**543.1**	**568.2**
Transportation										
Petroleum[3]	485.8	556.3	556.2	556.3	607.2	606.6	607.0	704.2	703.0	703.7
Natural Gas[4]	9.5	12.8	12.5	12.7	14.4	14.0	14.3	18.1	16.6	17.6
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	4.4	5.8	5.4	5.7	7.9	6.6	7.3
Total[3]	**498.2**	**573.6**	**573.1**	**573.4**	**627.5**	**626.1**	**627.1**	**730.2**	**726.3**	**728.7**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	693.8	693.9	749.0	747.6	748.6	853.1	849.6	851.8
Natural Gas	266.0	298.8	298.4	298.6	315.1	316.3	315.4	352.0	357.4	354.1
Coal	58.8	68.8	68.7	68.7	68.8	68.8	68.8	69.0	69.1	68.8
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	643.6	625.2	639.8	692.8	637.9	676.6	777.0	640.0	721.0
Total[3]	**1510.8**	**1705.0**	**1686.2**	**1701.0**	**1825.7**	**1770.8**	**1809.5**	**2051.2**	**1916.1**	**1995.8**
Electric Generators[6]										
Petroleum	20.0	9.4	7.4	7.9	5.8	4.0	4.8	5.2	2.9	3.8
Natural Gas	45.8	79.6	71.6	78.3	100.0	82.1	96.6	164.1	102.7	141.6
Coal	490.5	554.6	546.2	553.6	587.0	551.8	575.1	607.7	534.3	575.7
Total	**556.3**	**643.6**	**625.2**	**639.8**	**692.8**	**637.9**	**676.6**	**777.0**	**640.0**	**721.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	701.2	701.8	754.8	751.7	753.4	858.3	852.5	855.5
Natural Gas	311.8	378.4	370.0	376.9	415.0	398.4	412.0	516.2	460.1	495.6
Coal	549.3	623.3	615.0	622.3	655.8	620.6	644.0	676.7	603.4	644.5
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**	**1705.0**	**1686.2**	**1701.0**	**1825.7**	**1770.8**	**1809.5**	**2051.2**	**1916.1**	**1995.8**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**5.9**	**6.0**	**6.3**	**5.9**	**6.1**

[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 20 to 25 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.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Table E14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	4.25	4.28	4.34	4.23	4.34	4.49	4.15	4.43
Sulfur Dioxide (million tons)	13.71	10.38	10.39	10.39	9.70	9.70	9.70	8.95	8.95	8.95
Mercury (tons)	43.60	45.24	44.97	45.23	45.60	44.12	45.22	45.07	42.16	44.32
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	625.23	639.80	692.78	637.94	676.58	776.99	639.96	721.01
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	4351	4314	4391	4516	4451	5037	5625	5491
Sulfur Dioxide (1999 dollars per ton)	0	190	182	196	187	170	176	241	147	190
Mercury (million 1999 dollars per ton)	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	0
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	5.9	5.9	7.1	5.9	5.9	14.8	9.8	9.8
Combustion	0.0	39.9	40.6	42.0	42.1	43.7	43.7	46.1	46.6	46.2
SCR Post-combustion	0.0	92.8	96.6	93.3	92.9	96.7	93.6	93.0	99.9	93.9
SNCR Post-combustion	0.0	25.2	18.3	22.0	26.3	19.8	23.7	43.4	39.0	46.9
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	585	595	642	596	627	721	592	663
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	448	452	464	443	459	440	426	440
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	185	184	188	186	187	179	170	172

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
RPS = Renewable Portfolio Standards.
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 M2BASE.D060801A, M2RPS20_X.D070601A, M2RPS20H_X.D070601A.

Appendix F

Tables for Alternative Hg Cap Cases

Table F1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.01	12.04	11.27	11.21	11.22	11.12	11.13	11.11
Natural Gas Plant Liquids	2.62	3.12	3.11	3.12	3.37	3.44	3.39	4.16	4.22	4.17
Dry Natural Gas	19.16	21.95	21.92	21.96	24.04	24.56	24.19	30.24	30.66	30.31
Coal	23.08	25.45	25.44	25.43	26.55	25.57	26.37	27.16	26.14	26.96
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[1]	6.53	7.13	7.13	7.13	7.90	8.09	7.87	8.42	8.62	8.42
Other[2]	1.65	0.35	0.35	0.35	0.31	0.38	0.30	0.33	0.32	0.32
Total	**73.29**	**77.88**	**77.87**	**77.93**	**81.19**	**80.99**	**81.09**	**87.97**	**87.63**	**87.88**
Imports										
Crude Oil[3]	18.96	21.42	21.40	21.40	22.38	22.46	22.45	25.82	25.84	25.84
Petroleum Products[4]	4.14	6.28	6.28	6.24	8.65	8.48	8.60	10.80	10.74	10.80
Natural Gas	3.63	5.13	5.13	5.13	5.55	5.61	5.57	6.59	6.66	6.62
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**	**33.93**	**33.91**	**33.87**	**37.54**	**37.51**	**37.59**	**44.18**	**44.20**	**44.22**
Exports										
Petroleum[6]	1.98	1.73	1.74	1.74	1.69	1.71	1.70	1.85	1.86	1.83
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	1.51	1.45	1.45	1.45	1.41	1.41	1.41
Total	**3.62**	**3.57**	**3.57**	**3.57**	**3.58**	**3.59**	**3.58**	**3.89**	**3.90**	**3.87**
Discrepancy[7]	**0.69**	**0.43**	**0.42**	**0.43**	**0.04**	**0.05**	**0.04**	**0.11**	**0.12**	**0.15**
Consumption										
Petroleum Products[8]	38.02	41.34	41.35	41.35	44.44	44.40	44.42	50.45	50.46	50.47
Natural Gas	22.21	26.44	26.40	26.44	29.00	29.58	29.17	36.06	36.53	36.12
Coal	21.42	24.39	24.39	24.37	25.64	24.66	25.46	26.42	25.40	26.22
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[1]	6.54	7.13	7.14	7.14	7.91	8.10	7.88	8.43	8.63	8.43
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**	**107.81**	**107.79**	**107.81**	**115.11**	**114.86**	**115.05**	**128.16**	**127.81**	**128.07**
Net Imports - Petroleum	**21.12**	**25.96**	**25.94**	**25.90**	**29.34**	**29.24**	**29.35**	**34.78**	**34.71**	**34.81**
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	2.96	2.96	2.96	2.87	2.91	2.89	3.22	3.36	3.24
Coal Minemouth Price (dollars per ton)	17.17	15.05	15.21	14.94	14.08	14.50	14.25	12.87	13.71	13.32
Average Electric Price (cents per Kwh)	6.6	6.4	6.4	6.4	6.1	6.2	6.2	6.2	6.3	6.2

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.40	0.40
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.23	1.23
Natural Gas	4.88	5.57	5.57	5.57	5.61	5.60	5.61	6.23	6.20	6.23
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	0.44	0.43	0.44
Electricity	3.91	4.57	4.56	4.57	4.95	4.93	4.94	5.79	5.77	5.79
Delivered Energy	**10.66**	**12.01**	**12.01**	**12.01**	**12.34**	**12.31**	**12.32**	**13.74**	**13.69**	**13.74**
Electricity Related Losses	8.44	9.67	9.66	9.67	10.10	10.00	10.08	10.85	10.75	10.83
Total	**19.10**	**21.68**	**21.67**	**21.68**	**22.44**	**22.31**	**22.40**	**24.59**	**24.45**	**24.57**
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	0.60	0.60	0.61	0.62	0.62	0.62	0.62	0.62	0.62
Natural Gas	3.14	3.99	3.99	3.99	4.17	4.16	4.17	4.44	4.42	4.43
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	4.39	4.39	4.39	4.91	4.90	4.90	5.62	5.60	5.62
Delivered Energy	**7.55**	**9.13**	**9.13**	**9.13**	**9.85**	**9.83**	**9.84**	**10.83**	**10.79**	**10.83**
Electricity Related Losses	7.91	9.30	9.30	9.30	10.01	9.93	10.00	10.51	10.43	10.51
Total	**15.46**	**18.44**	**18.43**	**18.43**	**19.86**	**19.76**	**19.84**	**21.34**	**21.22**	**21.34**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.22	1.22	1.31	1.31	1.31	1.49	1.50	1.49
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.53	2.51	2.53	2.85	2.86	2.87
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.25	0.25	0.28	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	4.44	4.44	4.44	4.71	4.71	4.71	5.02	5.03	5.03
Petroleum Subtotal	9.45	9.86	9.87	9.87	10.57	10.56	10.57	11.63	11.64	11.65
Natural Gas[6]	9.80	10.46	10.45	10.46	11.27	11.32	11.28	12.73	12.73	12.70
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	1.81	1.81	1.81	1.83	1.82	1.82	1.87	1.87	1.86
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.58	2.58	2.60	2.59	2.59
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.61	3.90	3.89	3.90	4.17	4.16	4.16	4.76	4.75	4.75
Delivered Energy	**27.56**	**29.23**	**29.23**	**29.23**	**31.24**	**31.26**	**31.24**	**34.80**	**34.79**	**34.77**
Electricity Related Losses	7.80	8.25	8.25	8.24	8.50	8.44	8.49	8.91	8.84	8.88
Total	**35.36**	**37.48**	**37.47**	**37.48**	**39.74**	**39.70**	**39.74**	**43.71**	**43.63**	**43.65**

Table F2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Transportation										
Distillate Fuel	5.13	6.28	6.28	6.28	7.00	6.99	7.00	8.22	8.21	8.22
Jet Fuel[8]	3.46	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Motor Gasoline[2]	15.92	17.67	17.67	17.67	18.97	18.97	18.97	21.26	21.27	21.26
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	0.87	0.87
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	0.30	0.30	0.30	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	29.03	29.03	31.68	31.67	31.68	36.73	36.72	36.73
Pipeline Fuel Natural Gas	0.66	0.83	0.83	0.83	0.91	0.92	0.91	1.10	1.11	1.10
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.15	0.16
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	0.01	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**	**30.03**	**30.03**	**30.04**	**32.83**	**32.84**	**32.84**	**38.20**	**38.20**	**38.20**
Electricity Related Losses	0.13	0.19	0.19	0.19	0.24	0.24	0.24	0.31	0.31	0.31
Total	**26.41**	**30.22**	**30.22**	**30.22**	**33.07**	**33.08**	**33.08**	**38.51**	**38.51**	**38.51**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.74	8.74	9.49	9.48	9.48	10.85	10.84	10.85
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.02	3.08	3.07	3.08	3.41	3.42	3.43
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.58	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.20	1.24	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.99	4.99	5.35	5.36	5.36
Petroleum Subtotal	37.01	40.90	40.90	40.91	44.16	44.15	44.17	50.21	50.22	50.23
Natural Gas[6]	18.50	20.91	20.90	20.90	22.05	22.10	22.06	24.66	24.61	24.62
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	1.95	1.94	1.94	2.00	1.99	1.99
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.71	2.71	2.71	2.70	2.71	2.72	2.71	2.71
Renewable Energy[13]	2.65	2.94	2.94	2.94	3.18	3.18	3.18	3.65	3.64	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.94	12.95	14.15	14.11	14.12	16.34	16.29	16.33
Delivered Energy	**72.05**	**80.41**	**80.40**	**80.41**	**86.27**	**86.24**	**86.24**	**97.57**	**97.48**	**97.54**
Electricity Related Losses	24.29	27.40	27.40	27.39	28.84	28.62	28.81	30.58	30.33	30.53
Total	**96.33**	**107.81**	**107.79**	**107.81**	**115.11**	**114.86**	**115.05**	**128.16**	**127.81**	**128.07**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.06	0.06	0.06	0.05	0.05	0.06	0.05	0.06
Residual Fuel	0.96	0.38	0.38	0.38	0.22	0.20	0.20	0.19	0.19	0.18
Petroleum Subtotal	1.02	0.44	0.45	0.44	0.28	0.25	0.26	0.25	0.24	0.24
Natural Gas	3.71	5.53	5.50	5.53	6.94	7.48	7.11	11.40	11.92	11.50
Steam Coal	18.77	21.68	21.68	21.66	22.93	21.96	22.75	23.70	22.69	23.51
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[15]	3.88	4.19	4.19	4.19	4.73	4.91	4.70	4.78	4.98	4.78
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**	**40.35**	**40.33**	**40.34**	**42.99**	**42.73**	**42.94**	**46.92**	**46.62**	**46.86**

Table F2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.80	8.80	9.54	9.53	9.54	10.91	10.89	10.91
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	3.90	3.90	3.90	4.51	4.51	4.51	5.97	5.97	5.97
Liquefied Petroleum Gas	2.88	3.02	3.03	3.02	3.08	3.07	3.08	3.41	3.42	3.43
Motor Gasoline[2]	16.17	17.93	17.93	17.93	19.24	19.24	19.24	21.57	21.58	21.57
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.01	1.48	1.48	1.48	1.42	1.40	1.40	1.42	1.43	1.42
Other Petroleum[12]	4.53	4.71	4.72	4.72	4.99	4.99	4.99	5.35	5.36	5.36
Petroleum Subtotal	38.02	41.34	41.35	41.35	44.44	44.40	44.42	50.45	50.46	50.47
Natural Gas	22.21	26.44	26.40	26.44	29.00	29.58	29.17	36.06	36.53	36.12
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	23.60	23.58	24.88	23.90	24.70	25.70	24.68	25.49
Net Coal Coke Imports	0.06	0.12	0.12	0.12	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	24.39	24.37	25.64	24.66	25.46	26.42	25.40	26.22
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.74	7.74	6.54	6.54	6.59
Renewable Energy[17]	6.54	7.13	7.14	7.14	7.91	8.10	7.88	8.43	8.63	8.43
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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**	**107.81**	**107.79**	**107.81**	**115.11**	**114.86**	**115.05**	**128.16**	**127.81**	**128.07**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.40	80.41	86.27	86.24	86.24	97.57	97.48	97.54
Total Energy Use	96.33	107.81	107.79	107.81	115.11	114.86	115.05	128.16	127.81	128.07
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	10960	10960	10960	12667	12667	12667	16515	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1704.5	1704.7	1825.7	1807.8	1823.1	2051.2	2031.0	2046.9

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Residential	**13.10**	**13.27**	**13.29**	**13.27**	**13.46**	**13.60**	**13.55**	**13.77**	**13.95**	**13.81**
Primary Energy[1]	6.71	7.49	7.49	7.49	7.18	7.21	7.19	7.08	7.18	7.10
Petroleum Products[2]	7.55	9.20	9.19	9.17	9.37	9.35	9.37	9.47	9.46	9.47
Distillate Fuel	6.27	7.45	7.44	7.41	7.57	7.57	7.57	7.78	7.77	7.77
Liquefied Petroleum Gas	10.36	12.60	12.60	12.60	12.86	12.79	12.86	12.75	12.73	12.77
Natural Gas	6.52	7.11	7.11	7.11	6.72	6.77	6.74	6.65	6.77	6.67
Electricity	23.47	22.16	22.21	22.17	22.30	22.60	22.50	22.44	22.72	22.52
Commercial	**13.18**	**12.70**	**12.71**	**12.70**	**12.25**	**12.40**	**12.32**	**12.69**	**12.89**	**12.68**
Primary Energy[1]	5.22	5.57	5.56	5.56	5.68	5.72	5.70	5.79	5.89	5.80
Petroleum Products[2]	4.99	6.13	6.12	6.10	6.29	6.28	6.29	6.40	6.39	6.39
Distillate Fuel	4.37	5.24	5.23	5.20	5.36	5.36	5.36	5.53	5.52	5.52
Residual Fuel	2.63	3.65	3.64	3.64	3.71	3.70	3.71	3.86	3.86	3.86
Natural Gas[3]	5.34	5.55	5.55	5.55	5.66	5.71	5.68	5.78	5.89	5.80
Electricity	21.45	20.26	20.29	20.27	18.76	19.02	18.89	19.00	19.28	18.94
Industrial[4]	**5.27**	**5.76**	**5.75**	**5.75**	**5.67**	**5.69**	**5.70**	**5.90**	**5.98**	**5.92**
Primary Energy	3.91	4.47	4.47	4.46	4.49	4.49	4.50	4.68	4.74	4.70
Petroleum Products[2]	5.54	6.00	6.00	5.98	6.13	6.08	6.13	6.16	6.15	6.18
Distillate Fuel	4.65	5.40	5.39	5.36	5.56	5.55	5.55	5.73	5.72	5.71
Liquefied Petroleum Gas	8.50	7.74	7.75	7.74	7.88	7.76	7.87	7.76	7.76	7.81
Residual Fuel	2.78	3.38	3.38	3.38	3.44	3.43	3.43	3.59	3.59	3.59
Natural Gas[5]	2.79	3.64	3.64	3.64	3.50	3.54	3.51	3.85	3.97	3.87
Metallurgical Coal	1.65	1.58	1.59	1.58	1.54	1.54	1.54	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.36	1.35	1.31	1.31	1.31	1.21	1.21	1.22
Electricity	13.00	12.80	12.80	12.81	12.08	12.29	12.23	12.22	12.50	12.25
Transportation	**8.30**	**9.39**	**9.39**	**9.36**	**9.69**	**9.68**	**9.69**	**9.20**	**9.19**	**9.20**
Primary Energy	8.29	9.38	9.37	9.35	9.68	9.67	9.67	9.18	9.18	9.18
Petroleum Products[2]	8.28	9.37	9.37	9.34	9.67	9.66	9.67	9.18	9.17	9.18
Distillate Fuel[6]	8.22	8.98	8.96	8.92	8.95	8.97	8.95	8.83	8.82	8.82
Jet Fuel[7]	4.70	5.29	5.28	5.25	5.49	5.50	5.49	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.81	10.78	11.31	11.29	11.31	10.60	10.59	10.60
Residual Fuel	2.46	3.11	3.11	3.11	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.07	14.07	14.07	13.99	14.07	13.70	13.68	13.74
Natural Gas[10]	7.02	7.28	7.28	7.28	7.21	7.26	7.23	7.41	7.52	7.42
Ethanol (E85)[11]	14.42	19.21	19.21	19.20	19.16	19.16	19.16	19.36	19.37	19.36
Methanol (M85)[12]	10.38	13.13	13.13	13.13	13.83	13.83	13.83	14.35	14.35	14.35
Electricity	15.59	14.52	14.59	14.51	13.62	14.00	13.81	13.22	13.47	13.21
Average End-Use Energy	**8.49**	**9.17**	**9.17**	**9.15**	**9.22**	**9.26**	**9.24**	**9.21**	**9.28**	**9.22**
Primary Energy	6.31	7.19	7.19	7.17	7.35	7.35	7.35	7.23	7.27	7.25
Electricity	19.41	18.65	18.67	18.66	17.99	18.24	18.15	18.19	18.46	18.21
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.63	1.64	1.59	1.66	1.60	1.88	1.99	1.89
Petroleum Products	2.49	3.61	3.61	3.61	3.90	3.94	3.93	4.17	4.16	4.18
Distillate Fuel	4.04	4.72	4.71	4.68	4.87	4.87	4.87	5.06	5.06	5.05
Residual Fuel	2.40	3.42	3.42	3.43	3.65	3.70	3.68	3.89	3.90	3.90
Natural Gas	2.58	3.44	3.43	3.44	3.26	3.32	3.29	3.71	3.85	3.74
Steam Coal	1.21	1.14	1.14	1.14	1.06	1.06	1.04	0.98	0.99	0.97

Table F3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.53	8.50	8.81	8.79	8.81	8.49	8.48	8.50
Distillate Fuel	7.25	8.14	8.12	8.09	8.20	8.22	8.20	8.20	8.19	8.19
Jet Fuel	4.70	5.29	5.28	5.25	5.49	5.50	5.49	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.64	8.63	8.74	8.64	8.74	8.54	8.54	8.58
Motor Gasoline[8]	9.45	10.80	10.81	10.78	11.31	11.29	11.31	10.60	10.59	10.60
Residual Fuel	2.47	3.25	3.25	3.25	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.05	4.72	4.72	4.72	4.47	4.49	4.48	4.60	4.72	4.62
Coal	1.23	1.16	1.16	1.16	1.08	1.09	1.07	1.00	1.01	0.99
Ethanol (E85)[11]	14.42	19.21	19.21	19.20	19.16	19.16	19.16	19.36	19.37	19.36
Methanol (M85)[12]	10.38	13.13	13.13	13.13	13.83	13.83	13.83	14.35	14.35	14.35
Electricity	19.41	18.65	18.67	18.66	17.99	18.24	18.15	18.19	18.46	18.21
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	153.93	153.83	160.41	161.56	161.16	183.27	184.94	183.77
Commercial	98.42	114.97	115.01	114.98	119.69	120.84	120.27	136.41	138.04	136.22
Industrial	111.66	127.05	126.98	126.93	133.28	133.99	133.95	154.57	156.85	154.99
Transportation	212.64	273.84	273.76	273.00	308.81	308.49	308.71	340.45	340.22	340.50
Total Non-Renewable Expenditures	556.99	669.69	669.67	668.73	722.19	724.87	724.08	814.69	820.05	815.48
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.64	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**670.09**	**669.16**	**722.82**	**725.50**	**724.71**	**815.54**	**820.89**	**816.33**

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	2106	2105	2245	2137	2214	2315	2198	2284
Petroleum	94	43	43	43	28	25	26	25	25	24
Natural Gas[2]	359	583	580	583	825	913	854	1495	1584	1521
Nuclear Power	730	740	740	740	725	725	725	613	613	617
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	373	373	397	407	393	400	412	399
Total	**3369**	**3844**	**3841**	**3844**	**4219**	**4207**	**4211**	**4847**	**4830**	**4845**
Non-Utility Generation for Own Use	16	17	17	17	17	17	17	17	16	16
Distributed Generation	0	0	0	0	1	1	1	5	5	5
Cogenerators[4]										
Coal	47	53	53	53	52	51	52	52	51	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	207	237	237	237	261	260	261	318	323	321
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	8
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**	**345**	**345**	**345**	**373**	**373**	**374**	**441**	**446**	**443**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	172	172	180	179	180	208	208	208
Generation for Own Use	156	178	178	178	198	199	199	238	243	240
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1145	1339	1337	1339	1452	1445	1448	1698	1692	1698
Commercial	1073	1288	1287	1288	1439	1435	1437	1646	1641	1647
Industrial	1058	1142	1142	1142	1222	1220	1221	1395	1391	1393
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3294**	**3794**	**3792**	**3794**	**4147**	**4135**	**4140**	**4788**	**4773**	**4787**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.8	7.7
Commercial	7.3	6.9	6.9	6.9	6.4	6.5	6.4	6.5	6.6	6.5
Industrial	4.4	4.4	4.4	4.4	4.1	4.2	4.2	4.2	4.3	4.2
Transportation	5.3	5.0	5.0	5.0	4.6	4.8	4.7	4.5	4.6	4.5
All Sectors Average	**6.6**	**6.4**	**6.4**	**6.4**	**6.1**	**6.2**	**6.2**	**6.2**	**6.3**	**6.2**
Prices by Service Category[9] (1999 cents per kwh)										
Generation	4.1	3.8	3.8	3.8	3.5	3.5	3.5	3.6	3.7	3.6
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	13.71	10.38	10.39	10.38	9.70	9.70	9.70	8.95	8.95	8.95
Nitrogen Oxide	5.45	4.30	3.41	3.42	4.34	3.38	3.44	4.49	3.52	3.56

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	303.9	303.8	318.6	305.7	315.9	318.5	303.9	315.2
Other Fossil Steam[3]	137.4	127.8	127.6	127.5	119.2	116.0	119.1	116.9	113.4	116.9
Combined Cycle	21.0	53.2	52.8	52.9	107.8	122.3	111.7	202.2	216.4	209.0
Combustion Turbine/Diesel	74.3	123.1	122.7	123.9	147.2	147.7	150.8	199.5	200.3	200.0
Nuclear Power	97.4	97.5	97.5	97.5	94.8	94.8	94.8	76.3	76.3	76.9
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	94.8	94.8	94.7	98.0	98.6	98.0	99.5	100.2	99.6
Distributed Generation[5]	0.0	0.7	0.7	0.7	2.5	2.7	2.7	11.5	11.6	10.4
Total	**743.4**	**820.4**	**819.4**	**820.6**	**907.8**	**907.6**	**912.7**	**1044.2**	**1041.8**	**1047.8**
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	1.1	1.0	18.9	6.2	16.3	20.5	6.2	17.5
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	19.4	19.1	19.1	74.2	88.7	78.1	168.6	182.8	175.4
Combustion Turbine/Diesel	0.0	38.9	38.7	39.8	64.7	65.4	68.2	117.2	118.1	117.6
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	0.4	0.4	2.0	2.7	2.1	2.0	2.7	2.1
Distributed Generation[5]	0.0	0.7	0.7	0.7	2.5	2.7	2.7	11.5	11.6	10.4
Total	**0.0**	**60.6**	**60.0**	**61.2**	**162.2**	**165.7**	**167.4**	**319.8**	**321.4**	**323.1**
Cumulative Total Additions	**0.0**	**92.6**	**92.0**	**93.2**	**195.9**	**199.3**	**201.1**	**355.1**	**356.7**	**358.4**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	5.6	5.6	7.2	7.5	7.4
Other Fossil Steam[3]	0.0	9.9	10.0	10.1	18.4	21.6	18.5	20.7	24.2	20.7
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	4.4	4.5	4.5	6.0	6.2	5.9	6.3	6.3	6.1
Nuclear Power	0.0	0.0	0.0	0.0	2.6	2.6	2.6	21.2	21.2	20.6
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**	**16.7**	**17.0**	**17.1**	**32.8**	**36.4**	**33.0**	**55.6**	**59.5**	**55.2**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	8.3	8.4	8.6	8.3	8.3
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	39.9	39.9	39.9	43.3	43.4	43.4	51.4	52.2	51.7
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	8.2	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**59.2**	**59.2**	**63.3**	**63.1**	**63.3**	**73.2**	**73.7**	**73.2**
Cumulative Additions[6]	**0.0**	**6.8**	**6.8**	**6.8**	**10.9**	**10.7**	**10.8**	**20.7**	**21.2**	**20.7**

Table F5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
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	152.0	202.3	197.3	200.6	155.5	142.3	145.5	147.9	136.4	138.1
Gross Domestic Trade	**334.2**	**327.6**	**322.5**	**325.9**	**258.4**	**245.2**	**248.4**	**147.9**	**136.4**	**138.1**
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)	4413.9	6468.6	6293.8	6380.3	4510.4	4157.2	4275.3	4605.1	4326.9	4317.8
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**12199.6**	**12286.1**	**9361.6**	**9008.4**	**9126.5**	**4605.1**	**4326.9**	**4317.8**
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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Production										
Dry Gas Production[1]	18.67	21.40	21.36	21.40	23.43	23.93	23.57	29.47	29.88	29.54
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**	**4.69**	**4.69**	**4.69**	**5.00**	**5.06**	**5.02**	**5.82**	**5.88**	**5.84**
Canada	3.29	4.48	4.48	4.47	4.72	4.77	4.74	5.43	5.49	5.44
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	0.80	0.80
Total Supply	**22.15**	**26.20**	**26.17**	**26.20**	**28.49**	**29.05**	**28.65**	**35.35**	**35.83**	**35.43**
Consumption by Sector										
Residential	4.75	5.42	5.42	5.42	5.46	5.46	5.46	6.07	6.04	6.07
Commercial	3.06	3.88	3.88	3.88	4.06	4.05	4.06	4.32	4.30	4.32
Industrial[3]	8.31	8.81	8.80	8.81	9.48	9.50	9.48	10.53	10.50	10.49
Electric Generators[4]	3.64	5.43	5.40	5.43	6.81	7.34	6.98	11.19	11.69	11.29
Lease and Plant Fuel[5]	1.23	1.38	1.37	1.38	1.50	1.52	1.51	1.87	1.89	1.88
Pipeline Fuel	0.64	0.81	0.81	0.81	0.88	0.90	0.89	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	**21.65**	**25.79**	**25.75**	**25.79**	**28.29**	**28.86**	**28.46**	**35.20**	**35.66**	**35.26**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.42**	**0.20**	**0.19**	**0.20**	**0.14**	**0.16**	**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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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, M2M9008A.D060801A, M2M9008M.D060801A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F8. 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	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.96	2.96	2.87	2.91	2.89	3.22	3.36	3.24
Average Import Price	2.29	2.95	2.95	2.95	2.64	2.66	2.65	2.72	2.75	2.73
Average[2]	**2.11**	**2.96**	**2.96**	**2.96**	**2.82**	**2.86**	**2.84**	**3.13**	**3.25**	**3.15**
Delivered Prices										
Residential	6.69	7.31	7.30	7.31	6.91	6.95	6.92	6.83	6.95	6.85
Commercial	5.49	5.70	5.70	5.70	5.82	5.86	5.83	5.93	6.05	5.95
Industrial[3]	2.87	3.74	3.74	3.74	3.59	3.63	3.61	3.95	4.08	3.97
Electric Generators[4]	2.63	3.50	3.50	3.50	3.32	3.38	3.35	3.78	3.92	3.81
Transportation[5]	7.21	7.48	7.47	7.48	7.40	7.45	7.42	7.61	7.73	7.62
Average[6]	**4.15**	**4.84**	**4.84**	**4.84**	**4.59**	**4.61**	**4.60**	**4.72**	**4.84**	**4.74**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.35	4.08	4.09	4.08	3.70	3.71	3.71
Commercial	3.37	2.74	2.74	2.74	2.99	3.00	2.99	2.81	2.81	2.81
Industrial[3]	0.76	0.78	0.78	0.78	0.77	0.77	0.77	0.82	0.83	0.82
Electric Generators[4]	0.52	0.54	0.54	0.54	0.49	0.52	0.51	0.65	0.67	0.66
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.59	4.58	4.48	4.48	4.48
Average[6]	**2.04**	**1.88**	**1.88**	**1.88**	**1.76**	**1.75**	**1.76**	**1.59**	**1.59**	**1.60**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.57	23.57	22.30	22.31	22.29	22.48	22.39	22.48
Commercial	10.32	10.63	10.63	10.63	12.16	12.16	12.14	12.12	12.06	12.11
Industrial[3]	6.28	6.86	6.85	6.86	7.26	7.31	7.26	8.65	8.72	8.64
Electric Generators[4]	1.88	2.94	2.91	2.94	3.36	3.83	3.54	7.24	7.87	7.46
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.41	0.41	0.68	0.67	0.68
Total	**40.32**	**44.25**	**44.20**	**44.24**	**45.49**	**46.02**	**45.63**	**51.18**	**51.72**	**51.38**

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	16.49	21.43	20.45	20.51	20.73	20.78	20.75	21.47	21.49	21.49
Production (million barrels per day)[2]										
U.S. Total	5.88	5.66	5.67	5.69	5.32	5.30	5.30	5.25	5.26	5.25
Lower 48 Onshore	3.27	2.81	2.81	2.82	2.52	2.51	2.51	2.75	2.75	2.75
Conventional	2.59	2.18	2.18	2.19	1.81	1.81	1.81	1.98	1.99	1.98
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.69	0.70	0.76	0.76	0.76
Lower 48 Offshore	1.56	2.06	2.07	2.08	2.16	2.14	2.14	1.87	1.87	1.86
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	15.75	15.73	15.73	14.55	14.48	14.50	14.11	14.10	14.08
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	2.08	2.96	2.96	2.96	2.87	2.91	2.89	3.22	3.36	3.24
Production (trillion cubic feet)[3]										
U.S. Total	18.67	21.40	21.36	21.40	23.43	23.93	23.57	29.47	29.88	29.54
Lower 48 Onshore	12.83	14.46	14.44	14.46	16.71	17.16	16.84	21.31	21.52	21.41
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.32	1.32	1.39	1.40	1.39
Non-Associated	11.03	12.95	12.92	12.95	15.39	15.83	15.51	19.91	20.12	20.02
Conventional	6.64	7.67	7.66	7.68	7.93	8.26	8.04	11.14	11.10	11.15
Unconventional	4.39	5.27	5.26	5.27	7.45	7.58	7.47	8.78	9.02	8.87
Lower 48 Offshore	5.43	6.47	6.46	6.47	6.22	6.27	6.23	7.59	7.79	7.56
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	5.41	5.40	5.41	5.13	5.18	5.14	6.56	6.75	6.52
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	167.88	167.95	167.94	185.55	184.65	185.26	200.71	199.48	199.94
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	28.87	28.98	29.11	29.86	30.25	29.92	39.36	41.09	39.30

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Production[1]										
Appalachia	433	426	429	424	421	403	417	396	383	396
Interior	185	182	185	179	180	174	195	161	173	184
West	486	624	616	630	694	653	669	783	705	740
East of the Mississippi	559	561	566	556	557	548	567	524	536	544
West of the Mississippi	544	672	664	677	738	681	715	817	725	776
Total	**1103**	**1233**	**1230**	**1233**	**1295**	**1229**	**1282**	**1340**	**1261**	**1320**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	57	57	56	56	56
Total	**-49**	**-44**	**-44**	**-44**	**-40**	**-40**	**-40**	**-36**	**-36**	**-36**
Total Supply[2]	**1054**	**1189**	**1186**	**1189**	**1254**	**1189**	**1242**	**1304**	**1225**	**1283**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	83	83	86	85	85
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1074	1077	1145	1080	1132	1196	1118	1176
Total	**1032**	**1189**	**1187**	**1190**	**1256**	**1191**	**1244**	**1306**	**1227**	**1285**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-2**	**-2**	**-2**	**-2**	**-2**	**-2**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	15.21	14.94	14.08	14.50	14.25	12.87	13.71	13.32
(1999 dollars per million Btu)	0.82	0.73	0.74	0.72	0.69	0.70	0.69	0.64	0.66	0.65
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.75	29.62	28.61	28.62	28.70	26.50	26.53	26.68
Coke Plants	44.28	42.39	42.53	42.38	41.36	41.34	41.29	38.52	38.72	38.71
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	22.96	22.87	21.28	21.65	20.99	19.41	20.06	19.38
(1999 dollars per million Btu)	1.21	1.14	1.14	1.14	1.06	1.06	1.04	0.98	0.99	0.97
Average	**25.77**	**23.78**	**23.85**	**23.75**	**22.13**	**22.52**	**21.87**	**20.15**	**20.80**	**20.15**
Exports[7]	37.44	36.39	36.50	36.34	35.66	35.58	35.51	33.09	33.22	33.23

[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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
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	3.43	3.43	3.43	4.93	5.38	5.00	4.95	5.40	5.02
Municipal Solid Waste[3]	2.61	2.96	2.96	2.96	3.42	3.63	3.43	3.93	4.14	3.94
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	7.76	7.76	7.76
Total	**88.83**	**94.75**	**94.75**	**94.75**	**97.98**	**98.63**	**98.05**	**99.49**	**100.15**	**99.61**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.20	301.20	301.13	301.13	301.13	300.07	300.06	300.07
Geothermal[2]	13.21	18.34	18.34	18.28	30.94	34.66	31.51	31.16	34.87	31.74
Municipal Solid Waste[3]	18.12	20.68	20.68	20.68	23.88	25.51	23.90	27.76	29.40	27.78
Wood and Other Biomass[4]	9.02	14.94	15.66	15.81	21.30	26.27	16.60	19.78	25.85	17.94
Dedicated Plants	7.73	9.16	9.16	9.16	11.36	11.37	11.36	13.82	13.83	14.08
Cofiring	1.29	5.78	6.50	6.65	9.94	14.89	5.24	5.95	12.02	3.85
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	18.83	18.84	18.83
Total	**355.43**	**372.61**	**373.33**	**373.42**	**397.03**	**407.35**	**392.92**	**400.32**	**411.74**	**399.09**
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	5.17	5.17	5.17	6.06	6.06	6.06	7.54	7.54	7.54
Total	**5.35**	**5.87**	**5.87**	**5.87**	**6.76**	**6.76**	**6.76**	**8.24**	**8.24**	**8.24**
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	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.12**	**33.97**	**33.97**	**33.97**	**39.05**	**39.05**	**39.05**	**47.57**	**47.57**	**47.57**
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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections 2005 Reference	2005 Hg 5-Ton Recycle	2005 Hg MACT 90%	2010 Reference	2010 Hg 5-Ton Recycle	2010 Hg MACT 90%	2020 Reference	2020 Hg 5-Ton Recycle	2020 Hg MACT 90%
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**	**0.44**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	0.43	0.44
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**	**2.42**	**2.42**	**2.42**	**2.64**	**2.64**	**2.64**	**3.08**	**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	2.23	2.23	2.23	2.46	2.46	2.46	2.90	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.21**	**0.22**	**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	0.20
Electric Generators[5]	**3.88**	**4.19**	**4.19**	**4.19**	**4.73**	**4.91**	**4.70**	**4.78**	**4.98**	**4.78**
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	0.44	0.44	0.44	0.85	0.96	0.87	0.85	0.97	0.87
Municipal Solid Waste[6]	0.25	0.28	0.28	0.28	0.32	0.35	0.33	0.38	0.40	0.38
Biomass	0.12	0.18	0.19	0.19	0.26	0.30	0.21	0.25	0.31	0.23
Dedicated Plants	0.10	0.11	0.11	0.11	0.14	0.13	0.14	0.17	0.17	0.18
Cofiring	0.02	0.07	0.08	0.08	0.12	0.17	0.06	0.07	0.14	0.05
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**	**7.31**	**7.31**	**7.31**	**8.10**	**8.28**	**8.06**	**8.62**	**8.82**	**8.62**
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	0.20	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**	**0.22**	**0.21**	**0.22**	**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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.5	23.2	23.3	23.3
Natural Gas	69.5	80.2	80.2	80.2	80.8	80.7	80.8	89.8	89.3	89.7
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	193.4	227.1	226.8	227.0	242.6	235.8	241.4	275.6	268.4	274.2
Total	**290.1**	**335.0**	**334.7**	**334.9**	**349.2**	**342.3**	**347.9**	**389.8**	**382.3**	**388.4**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.0	12.1	12.1	12.1	12.1
Natural Gas	45.4	57.4	57.4	57.4	60.1	60.0	60.0	63.9	63.6	63.8
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	218.3	218.3	240.4	234.2	239.5	267.1	260.4	266.0
Total	**242.1**	**289.4**	**289.3**	**289.3**	**314.3**	**308.0**	**313.4**	**345.0**	**338.0**	**343.8**
Industrial[1]										
Petroleum	104.2	99.2	99.3	99.3	105.3	105.2	105.4	113.6	113.9	114.0
Natural Gas[2]	141.6	148.4	148.2	148.4	159.8	160.3	159.8	180.3	180.5	180.1
Coal	55.9	65.8	65.8	65.8	65.6	65.4	65.5	65.8	65.7	65.6
Electricity	178.8	193.6	193.6	193.6	204.1	199.0	203.5	226.4	220.6	224.9
Total	**480.4**	**507.0**	**506.9**	**507.0**	**534.8**	**529.9**	**534.2**	**586.1**	**580.7**	**584.6**
Transportation										
Petroleum[3]	485.8	556.3	556.3	556.3	607.2	607.2	607.3	704.2	704.1	704.1
Natural Gas[4]	9.5	12.8	12.8	12.8	14.4	14.6	14.4	18.1	18.2	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	4.4	4.4	5.8	5.6	5.8	7.9	7.7	7.8
Total[3]	**498.2**	**573.6**	**573.5**	**573.6**	**627.5**	**627.5**	**627.6**	**730.2**	**730.1**	**730.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	693.9	694.0	749.0	748.9	749.2	853.1	853.4	853.5
Natural Gas	266.0	298.8	298.7	298.8	315.1	315.5	315.0	352.0	351.6	351.8
Coal	58.8	68.8	68.7	68.7	68.8	68.6	68.7	69.0	68.8	68.8
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	643.6	643.1	643.2	692.8	674.7	690.1	777.0	757.1	772.8
Total[3]	**1510.8**	**1705.0**	**1704.5**	**1704.7**	**1825.7**	**1807.8**	**1823.1**	**2051.2**	**2031.0**	**2046.9**
Electric Generators[6]										
Petroleum	20.0	9.4	9.4	9.3	5.8	5.3	5.4	5.2	5.1	5.0
Natural Gas	45.8	79.6	79.2	79.7	100.0	107.7	102.4	164.1	171.6	165.6
Coal	490.5	554.6	554.5	554.2	587.0	561.7	582.3	607.7	580.4	602.2
Total	**556.3**	**643.6**	**643.1**	**643.2**	**692.8**	**674.7**	**690.1**	**777.0**	**757.1**	**772.8**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	703.3	703.3	754.8	754.2	754.6	858.3	858.5	858.5
Natural Gas	311.8	378.4	377.9	378.4	415.0	423.2	417.4	516.2	523.2	517.4
Coal	549.3	623.3	623.2	622.9	655.8	630.3	651.0	676.7	649.3	670.9
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**	**1705.0**	**1704.5**	**1704.7**	**1825.7**	**1807.8**	**1823.1**	**2051.2**	**2031.0**	**2046.9**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.0**	**6.1**	**6.3**	**6.2**	**6.3**

[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 20 to 25 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.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Table F14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%	Reference	Hg 5-Ton Recycle	Hg MACT 90%
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.41	3.42	4.34	3.38	3.44	4.49	3.52	3.56
Sulfur Dioxide (million tons)	13.71	10.38	10.39	10.38	9.70	9.70	9.70	8.95	8.95	8.95
Mercury (tons)	43.60	45.24	45.03	45.40	45.60	5.00	8.00	45.07	5.00	8.01
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	643.11	643.19	692.78	674.69	690.13	776.99	757.09	772.83
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	3652	4159	4391	3140	4162	5037	4682	4798
Sulfur Dioxide (1999 dollars per ton)	0	190	185	204	187	118	114	241	109	145
Mercury (million 1999 dollars per ton)	0	0	0	0	0	80	0	0	92	0
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	0	0	0	0	0	0	0	0
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	9.6	4.4	7.1	12.3	27.2	14.8	25.2	27.2
Combustion	0.0	39.9	38.4	38.2	42.1	41.3	42.9	46.1	45.6	48.7
SCR Post-combustion	0.0	92.8	95.8	93.5	92.9	95.8	93.5	93.0	98.2	94.5
SNCR Post-combustion	0.0	25.2	21.4	24.4	26.3	21.7	25.4	43.4	26.5	36.3
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	586	603	642	616	617	721	664	677
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	455	451	464	441	459	440	428	452
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	188	179	188	173	206	179	170	190

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
Hg = Mercury.
MACT = Maximum available controlled technology.
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 M2BASE.D060801A, M2M9008A.D060801A, M2M9008M.D060801A.

Appendix G

Tables for Integrated Cases With Three Emissions Caps

Table G1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.02	12.00	11.27	11.17	11.21	11.12	11.24	11.39
Natural Gas Plant Liquids	2.62	3.12	3.05	3.04	3.37	3.45	3.58	4.16	4.31	4.30
Dry Natural Gas	19.16	21.95	21.43	21.39	24.04	24.59	25.55	30.24	31.34	31.23
Coal	23.08	25.45	24.23	24.27	26.55	17.80	15.22	27.16	14.93	13.41
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.95	6.54	7.15	7.27
Renewable Energy[1]	6.53	7.13	8.14	8.23	7.90	9.97	10.02	8.42	10.65	11.08
Other[2]	1.65	0.35	0.58	0.58	0.31	0.30	0.30	0.33	0.33	0.33
Total	**73.29**	**77.88**	**77.35**	**77.41**	**81.19**	**75.18**	**73.84**	**87.97**	**79.94**	**79.00**
Imports										
Crude Oil[3]	18.96	21.42	21.39	21.41	22.38	22.51	22.49	25.82	25.82	25.68
Petroleum Products[4]	4.14	6.28	5.84	5.84	8.65	8.22	8.03	10.80	10.31	10.31
Natural Gas	3.63	5.13	5.14	5.13	5.55	6.78	6.88	6.59	8.18	8.27
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.88	0.89	0.96	0.81	0.81
Total	**27.37**	**33.93**	**33.38**	**33.39**	**37.54**	**38.39**	**38.29**	**44.18**	**45.11**	**45.07**
Exports										
Petroleum[6]	1.98	1.73	1.76	1.75	1.69	1.72	1.72	1.85	1.85	1.80
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.12	0.12	0.63	0.12	0.12
Coal	1.48	1.51	1.51	1.51	1.45	1.52	1.50	1.41	1.56	1.48
Total	**3.62**	**3.57**	**3.59**	**3.58**	**3.58**	**3.36**	**3.34**	**3.89**	**3.54**	**3.40**
Discrepancy[7]	**0.69**	**0.43**	**0.56**	**0.52**	**0.04**	**0.02**	**0.01**	**0.11**	**0.19**	**0.04**
Consumption										
Petroleum Products[8]	38.02	41.34	40.91	40.91	44.44	44.07	44.04	50.45	50.24	50.29
Natural Gas	22.21	26.44	25.93	25.87	29.00	31.07	32.11	36.06	39.23	39.22
Coal	21.42	24.39	23.08	23.16	25.64	16.65	14.13	26.42	13.68	12.38
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.95	6.54	7.15	7.27
Renewable Energy[1]	6.54	7.13	8.14	8.24	7.91	9.97	10.03	8.43	10.65	11.08
Other[9]	0.35	0.61	0.61	0.61	0.38	0.51	0.52	0.25	0.38	0.38
Total	**96.33**	**107.81**	**106.58**	**106.69**	**115.11**	**110.18**	**108.78**	**128.16**	**121.32**	**120.63**
Net Imports - Petroleum	**21.12**	**25.96**	**25.47**	**25.49**	**29.34**	**29.01**	**28.81**	**34.78**	**34.27**	**34.19**
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	2.96	2.80	2.79	2.87	3.24	3.50	3.22	3.69	3.80
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.96	15.11	14.08	13.42	13.43	12.87	11.90	12.16
Average Electric Price (cents per Kwh)	6.6	6.4	6.7	6.7	6.1	8.1	8.6	6.2	8.4	8.6

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.81	0.81	0.76	0.77	0.77
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.41	0.41
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.25	1.25
Natural Gas	4.88	5.57	5.60	5.60	5.61	5.57	5.52	6.23	6.22	6.22
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	0.44	0.43	0.43
Electricity	3.91	4.57	4.50	4.50	4.95	4.61	4.54	5.79	5.33	5.26
Delivered Energy	**10.66**	**12.01**	**11.97**	**11.97**	**12.34**	**11.95**	**11.83**	**13.74**	**13.28**	**13.21**
Electricity Related Losses	8.44	9.67	9.35	9.39	10.10	8.74	8.31	10.85	8.91	8.74
Total	**19.10**	**21.68**	**21.32**	**21.36**	**22.44**	**20.68**	**20.14**	**24.59**	**22.20**	**21.95**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.37	0.38	0.40
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	0.60	0.61	0.61	0.62	0.62	0.62	0.62	0.63	0.65
Natural Gas	3.14	3.99	4.01	4.01	4.17	4.15	4.11	4.44	4.83	4.95
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	4.39	4.34	4.34	4.91	4.61	4.55	5.62	5.09	4.99
Delivered Energy	**7.55**	**9.13**	**9.11**	**9.11**	**9.85**	**9.53**	**9.44**	**10.83**	**10.70**	**10.74**
Electricity Related Losses	7.91	9.30	9.03	9.06	10.01	8.74	8.33	10.51	8.51	8.29
Total	**15.46**	**18.44**	**18.13**	**18.17**	**19.86**	**18.27**	**17.77**	**21.34**	**19.21**	**19.03**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.21	1.21	1.31	1.29	1.29	1.49	1.49	1.48
Liquefied Petroleum Gas	2.32	2.45	2.43	2.42	2.53	2.54	2.56	2.85	2.87	2.90
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.26	0.26	0.28	0.29	0.29
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.42	4.42	4.71	4.72	4.73	5.02	5.09	5.09
Petroleum Subtotal	9.45	9.86	9.80	9.80	10.57	10.58	10.61	11.63	11.70	11.75
Natural Gas[6]	9.80	10.46	10.44	10.44	11.27	11.35	11.32	12.73	13.38	13.38
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	1.81	1.80	1.80	1.83	1.78	1.78	1.87	1.83	1.83
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.54	2.53	2.60	2.55	2.54
Renewable Energy[7]	2.15	2.42	2.41	2.41	2.64	2.63	2.63	3.08	3.08	3.08
Electricity	3.61	3.90	3.83	3.83	4.17	3.88	3.86	4.76	4.06	3.98
Delivered Energy	**27.56**	**29.23**	**29.06**	**29.06**	**31.24**	**30.99**	**30.95**	**34.80**	**34.77**	**34.73**
Electricity Related Losses	7.80	8.25	7.97	8.00	8.50	7.37	7.07	8.91	6.79	6.61
Total	**35.36**	**37.48**	**37.03**	**37.06**	**39.74**	**38.36**	**38.02**	**43.71**	**41.57**	**41.34**

Table G2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections 2005 Reference	2005 NO_x, SO_2, CO_2 1990	2005 NO_x, SO_2, CO_2 1990-7%	2010 Reference	2010 NO_x, SO_2, CO_2 1990	2010 NO_x, SO_2, CO_2 1990-7%	2020 Reference	2020 NO_x, SO_2, CO_2 1990	2020 NO_x, SO_2, CO_2 1990-7%
Transportation										
Distillate Fuel	5.13	6.28	6.23	6.23	7.00	6.89	6.86	8.22	8.11	8.10
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.48	5.97	5.96	5.96
Motor Gasoline[2]	15.92	17.67	17.64	17.64	18.97	18.90	18.88	21.26	21.21	21.19
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	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	0.30	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.92	28.92	31.68	31.48	31.42	36.73	36.56	36.53
Pipeline Fuel Natural Gas	0.66	0.83	0.82	0.82	0.91	0.93	0.96	1.10	1.15	1.15
Compressed Natural Gas	0.02	0.06	0.05	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	0.01	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**	**30.03**	**29.91**	**29.91**	**32.83**	**32.65**	**32.63**	**38.20**	**38.07**	**38.04**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.22	0.22	0.31	0.28	0.27
Total	**26.41**	**30.22**	**30.09**	**30.09**	**33.07**	**32.87**	**32.85**	**38.51**	**38.35**	**38.31**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.68	8.68	9.49	9.36	9.35	10.85	10.75	10.76
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.09	3.12	3.41	3.43	3.47
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.17	19.15	21.57	21.51	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.20	1.21	1.24	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	5.01	5.01	5.35	5.42	5.42
Petroleum Subtotal	37.01	40.90	40.73	40.73	44.16	43.97	43.96	50.21	50.14	50.18
Natural Gas[6]	18.50	20.91	20.92	20.92	22.05	22.09	22.00	24.66	25.73	25.85
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.95	1.91	1.90	2.00	1.96	1.95
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.70	2.70	2.71	2.66	2.66	2.72	2.68	2.67
Renewable Energy[13]	2.65	2.94	2.93	2.93	3.18	3.17	3.17	3.65	3.64	3.63
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.76	12.76	14.15	13.21	13.07	16.34	14.64	14.39
Delivered Energy	**72.05**	**80.41**	**80.04**	**80.05**	**86.27**	**85.12**	**84.85**	**97.57**	**96.83**	**96.72**
Electricity Related Losses	24.29	27.40	26.53	26.64	28.84	25.07	23.93	30.58	24.50	23.91
Total	**96.33**	**107.81**	**106.58**	**106.69**	**115.11**	**110.18**	**108.78**	**128.16**	**121.32**	**120.63**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.03	0.03	0.06	0.02	0.01	0.06	0.02	0.03
Residual Fuel	0.96	0.38	0.15	0.14	0.22	0.08	0.07	0.19	0.08	0.08
Petroleum Subtotal	1.02	0.44	0.18	0.18	0.28	0.10	0.08	0.25	0.10	0.12
Natural Gas	3.71	5.53	5.01	4.95	6.94	8.98	10.12	11.40	13.50	13.37
Steam Coal	18.77	21.68	20.38	20.46	22.93	13.99	11.47	23.70	11.00	9.72
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.95	6.54	7.15	7.27
Renewable Energy[15]	3.88	4.19	5.21	5.31	4.73	6.80	6.86	4.78	7.02	7.45
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.50	0.51	0.24	0.37	0.37
Total	**35.52**	**40.35**	**39.29**	**39.40**	**42.99**	**38.28**	**36.99**	**46.92**	**39.14**	**38.31**

Table G2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1998	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.72	8.72	9.54	9.38	9.36	10.91	10.76	10.79
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.09	3.12	3.41	3.43	3.47
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.17	19.15	21.57	21.51	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	2.01	1.48	1.25	1.25	1.42	1.29	1.28	1.42	1.33	1.33
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	5.01	5.01	5.35	5.42	5.42
Petroleum Subtotal	38.02	41.34	40.91	40.91	44.44	44.07	44.04	50.45	50.24	50.29
Natural Gas	22.21	26.44	25.93	25.87	29.00	31.07	32.11	36.06	39.23	39.22
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	22.30	22.37	24.88	15.90	13.37	25.70	12.96	11.67
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	23.08	23.16	25.64	16.65	14.13	26.42	13.68	12.38
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.95	6.54	7.15	7.27
Renewable Energy[17]	6.54	7.13	8.14	8.24	7.91	9.97	10.03	8.43	10.66	11.09
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	0.50	0.51	0.24	0.37	0.37
Total	**96.33**	**107.81**	**106.58**	**106.69**	**115.11**	**110.18**	**108.78**	**128.16**	**121.32**	**120.63**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.04	80.05	86.27	85.12	84.85	97.57	96.83	96.72
Total Energy Use	96.33	107.81	106.58	106.69	115.11	110.18	108.78	128.16	121.32	120.63
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	10960	10904	10904	12667	12620	12610	16515	16523	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1655.9	1656.9	1825.7	1618.3	1568.0	2051.2	1765.6	1733.1

[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.
[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Residential	**13.10**	**13.27**	**13.56**	**13.55**	**13.46**	**15.71**	**16.39**	**13.77**	**16.19**	**16.42**
Primary Energy[1]	6.71	7.49	7.38	7.37	7.18	7.47	7.65	7.08	7.42	7.51
Petroleum Products[2]	7.55	9.20	9.14	9.14	9.37	9.43	9.40	9.47	9.43	9.45
Distillate Fuel	6.27	7.45	7.37	7.37	7.57	7.56	7.56	7.78	7.74	7.74
Liquefied Petroleum Gas	10.36	12.60	12.57	12.58	12.86	13.07	13.00	12.75	12.65	12.73
Natural Gas	6.52	7.11	6.98	6.98	6.72	7.07	7.29	6.65	7.07	7.17
Electricity	23.47	22.16	23.27	23.23	22.30	28.08	29.64	22.44	28.57	29.15
Commercial	**13.18**	**12.70**	**13.20**	**13.17**	**12.25**	**15.42**	**16.27**	**12.69**	**15.69**	**15.88**
Primary Energy[1]	5.22	5.57	5.45	5.45	5.68	5.97	6.16	5.79	6.13	6.21
Petroleum Products[2]	4.99	6.13	6.07	6.07	6.29	6.30	6.27	6.40	6.34	6.31
Distillate Fuel	4.37	5.24	5.16	5.17	5.36	5.33	5.32	5.53	5.48	5.47
Residual Fuel	2.63	3.65	3.61	3.61	3.71	3.69	3.69	3.86	3.84	3.84
Natural Gas[3]	5.34	5.55	5.42	5.42	5.66	6.00	6.23	5.78	6.18	6.28
Electricity	21.45	20.26	21.56	21.50	18.76	25.34	26.94	19.00	26.09	26.88
Industrial[4]	**5.27**	**5.76**	**5.80**	**5.80**	**5.67**	**6.49**	**6.75**	**5.90**	**6.63**	**6.75**
Primary Energy	3.91	4.47	4.38	4.38	4.49	4.65	4.76	4.68	4.82	4.90
Petroleum Products[2]	5.54	6.00	5.94	5.94	6.13	6.15	6.14	6.16	6.08	6.14
Distillate Fuel	4.65	5.40	5.33	5.33	5.56	5.50	5.49	5.73	5.69	5.69
Liquefied Petroleum Gas	8.50	7.74	7.70	7.70	7.88	8.08	8.03	7.76	7.68	7.81
Residual Fuel	2.78	3.38	3.34	3.34	3.44	3.42	3.42	3.59	3.58	3.58
Natural Gas[5]	2.79	3.64	3.51	3.50	3.50	3.85	4.10	3.85	4.29	4.39
Metallurgical Coal	1.65	1.58	1.58	1.59	1.54	1.55	1.55	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.35	1.31	1.22	1.20	1.21	1.10	1.08
Electricity	13.00	12.80	13.72	13.67	12.08	17.22	18.43	12.22	17.97	18.59
Transportation	**8.30**	**9.39**	**9.35**	**9.35**	**9.69**	**9.73**	**9.75**	**9.20**	**9.23**	**9.21**
Primary Energy	8.29	9.38	9.33	9.33	9.68	9.71	9.72	9.18	9.20	9.18
Petroleum Products[2]	8.28	9.37	9.33	9.33	9.67	9.70	9.72	9.18	9.19	9.17
Distillate Fuel[6]	8.22	8.98	8.89	8.90	8.95	8.94	8.94	8.83	8.82	8.82
Jet Fuel[7]	4.70	5.29	5.23	5.23	5.49	5.48	5.48	5.72	5.72	5.71
Motor Gasoline[8]	9.45	10.81	10.77	10.77	11.31	11.36	11.39	10.60	10.62	10.59
Residual Fuel	2.46	3.11	3.10	3.09	3.18	3.17	3.17	3.33	3.32	3.32
Liquid Petroleum Gas[9]	12.87	14.07	14.03	14.04	14.07	14.30	14.25	13.70	13.61	13.74
Natural Gas[10]	7.02	7.28	7.14	7.14	7.21	7.56	7.78	7.41	7.80	7.89
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.23	19.28	19.36	19.43	19.44
Methanol (M85)[12]	10.38	13.13	12.99	12.99	13.83	13.84	13.83	14.35	14.36	14.35
Electricity	15.59	14.52	15.01	15.00	13.62	16.93	17.72	13.22	16.46	16.79
Average End-Use Energy	**8.49**	**9.17**	**9.27**	**9.26**	**9.22**	**10.19**	**10.47**	**9.21**	**10.14**	**10.22**
Primary Energy	6.31	7.19	7.12	7.11	7.35	7.46	7.54	7.23	7.31	7.34
Electricity	19.41	18.65	19.76	19.71	17.99	23.83	25.28	18.19	24.63	25.30
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.55	1.54	1.59	2.11	2.46	1.88	2.81	2.97
Petroleum Products	2.49	3.61	3.83	3.85	3.90	4.26	4.40	4.17	4.51	4.55
Distillate Fuel	4.04	4.72	4.72	4.73	4.87	4.92	4.92	5.06	5.13	5.01
Residual Fuel	2.40	3.42	3.64	3.65	3.65	4.13	4.29	3.89	4.39	4.36
Natural Gas	2.58	3.44	3.41	3.40	3.26	3.90	4.21	3.71	4.40	4.51
Steam Coal	1.21	1.14	1.07	1.07	1.06	0.95	0.91	0.98	0.85	0.82

Table G3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.51	8.51	8.81	8.85	8.86	8.49	8.49	8.49
Distillate Fuel	7.25	8.14	8.07	8.08	8.20	8.20	8.19	8.20	8.19	8.18
Jet Fuel	4.70	5.29	5.23	5.23	5.49	5.48	5.48	5.72	5.72	5.71
Liquefied Petroleum Gas	8.84	8.63	8.60	8.60	8.74	8.94	8.89	8.54	8.47	8.59
Motor Gasoline[8]	9.45	10.80	10.77	10.77	11.31	11.36	11.39	10.60	10.62	10.59
Residual Fuel	2.47	3.25	3.23	3.23	3.33	3.32	3.32	3.49	3.48	3.48
Natural Gas	4.05	4.72	4.64	4.63	4.47	4.82	5.04	4.60	5.08	5.19
Coal	1.23	1.16	1.10	1.10	1.08	0.99	0.95	1.00	0.89	0.87
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.23	19.28	19.36	19.43	19.44
Methanol (M85)[12]	10.38	13.13	12.99	12.99	13.83	13.84	13.83	14.35	14.36	14.35
Electricity	19.41	18.65	19.76	19.71	17.99	23.83	25.28	18.19	24.63	25.30
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	156.62	156.46	160.41	180.98	186.99	183.27	208.08	209.81
Commercial	98.42	114.97	119.11	118.83	119.69	145.65	152.18	136.41	166.62	169.30
Industrial	111.66	127.05	127.75	127.56	133.28	152.48	158.61	154.57	174.97	177.83
Transportation	212.64	273.84	271.57	271.56	308.81	308.13	308.22	340.45	339.89	338.97
Total Non-Renewable Expenditures	556.99	669.69	675.06	674.41	722.19	787.23	806.00	814.69	889.56	895.91
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.63	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**675.48**	**674.82**	**722.82**	**787.86**	**806.63**	**815.54**	**890.41**	**896.76**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	1989	1995	2245	1387	1145	2315	1096	974
Petroleum	94	43	19	18	28	11	9	25	11	13
Natural Gas [2]	359	583	625	618	825	1265	1458	1495	1977	1963
Nuclear Power	730	740	740	740	725	741	744	613	669	681
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	418	420	397	511	512	400	525	564
Total	**3369**	**3844**	**3790**	**3790**	**4219**	**3914**	**3868**	**4847**	**4277**	**4195**
Non-Utility Generation for Own Use	16	17	21	21	17	20	20	17	19	18
Distributed Generation	0	0	0	0	1	1	1	5	2	1
Cogenerators[4]										
Coal	47	53	52	52	52	46	44	52	40	40
Petroleum	9	10	10	10	10	10	10	10	10	11
Natural Gas	207	237	242	242	261	320	321	318	595	641
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	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**	**345**	**350**	**350**	**373**	**427**	**427**	**441**	**707**	**753**
Other End-Use Generators [7]	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	172	170	170	180	183	181	208	265	280
Generation for Own Use	156	178	184	184	198	249	250	238	447	478
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**47**	**49**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1145	1339	1318	1318	1452	1350	1329	1698	1562	1542
Commercial	1073	1288	1272	1272	1439	1350	1334	1646	1491	1462
Industrial	1058	1142	1123	1123	1222	1138	1132	1395	1190	1167
Transportation	17	26	26	26	35	34	34	49	48	48
Total	**3294**	**3794**	**3739**	**3740**	**4147**	**3873**	**3830**	**4788**	**4291**	**4218**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.9	7.9	7.6	9.6	10.1	7.7	9.7	9.9
Commercial	7.3	6.9	7.4	7.3	6.4	8.6	9.2	6.5	8.9	9.2
Industrial	4.4	4.4	4.7	4.7	4.1	5.9	6.3	4.2	6.1	6.3
Transportation	5.3	5.0	5.1	5.1	4.6	5.8	6.0	4.5	5.6	5.7
All Sectors Average	**6.6**	**6.4**	**6.7**	**6.7**	**6.1**	**8.1**	**8.6**	**6.2**	**8.4**	**8.6**
Prices by Service Category [9] (1999 cents per kwh)										
Generation	4.1	3.8	4.2	4.1	3.5	5.4	5.8	3.6	5.7	5.9
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.8	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.71	10.38	8.55	8.55	9.70	4.52	4.02	8.95	3.27	3.27
Nitrogen Oxide	5.45	4.30	3.06	3.05	4.34	1.65	1.42	4.49	1.38	1.31

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	302.8	302.8	318.6	269.2	266.0	318.5	240.0	221.2
Other Fossil Steam[3]	137.4	127.8	119.9	119.9	119.2	103.6	104.6	116.9	94.3	91.1
Combined Cycle	21.0	53.2	84.4	84.5	107.8	174.5	205.3	202.2	269.0	273.8
Combustion Turbine/Diesel	74.3	123.1	114.8	116.3	147.2	119.0	119.9	199.5	135.7	128.8
Nuclear Power	97.4	97.5	97.5	97.5	94.8	96.9	97.5	76.3	85.7	87.6
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	94.8	98.7	99.6	98.0	106.6	109.3	99.5	112.9	123.3
Distributed Generation[5]	0.0	0.7	0.6	0.7	2.5	1.2	1.2	11.5	3.5	2.3
Total	**743.4**	**820.4**	**838.2**	**840.7**	**907.8**	**890.7**	**923.5**	**1044.2**	**960.9**	**948.0**
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	0.0	0.0	18.9	0.0	0.0	20.5	0.0	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	19.4	50.7	50.7	74.2	140.9	171.6	168.6	235.3	240.1
Combustion Turbine/Diesel	0.0	38.9	32.0	33.3	64.7	37.7	38.2	117.2	54.6	47.4
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	4.4	5.2	2.0	10.7	13.3	2.0	15.5	25.8
Distributed Generation[5]	0.0	0.7	0.6	0.7	2.5	1.2	1.2	11.5	3.5	2.3
Total	**0.0**	**60.6**	**87.7**	**90.0**	**162.2**	**190.4**	**224.4**	**319.8**	**308.9**	**315.7**
Cumulative Total Additions	**0.0**	**92.6**	**119.7**	**122.0**	**195.9**	**224.1**	**258.1**	**355.1**	**344.2**	**351.0**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	35.9	39.1	7.2	65.1	83.9
Other Fossil Steam[3]	0.0	9.9	17.8	17.7	18.4	34.1	33.0	20.7	43.3	46.5
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	4.4	5.7	5.5	6.0	7.1	6.8	6.3	7.4	7.1
Nuclear Power	0.0	0.0	0.0	0.0	2.6	0.6	0.0	21.2	11.8	9.8
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**	**16.7**	**26.0**	**25.7**	**32.8**	**78.0**	**79.1**	**55.6**	**127.9**	**147.6**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.5	7.3	8.6	6.8	6.6
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0
Natural Gas	34.6	39.9	40.8	40.8	43.3	51.6	51.8	51.4	89.7	97.1
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.2	1.1
Renewable Sources[4]	5.4	5.9	5.9	5.9	6.8	6.8	6.8	8.2	8.3	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**60.1**	**60.2**	**63.3**	**70.5**	**70.6**	**73.2**	**109.7**	**117.0**
Cumulative Additions[6]	**0.0**	**6.8**	**7.7**	**7.7**	**10.9**	**18.1**	**18.2**	**20.7**	**57.3**	**64.6**

Table G5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
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	1.4
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.4

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
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	152.0	202.3	154.1	152.9	155.5	65.7	57.4	147.9	73.9	81.1
Gross Domestic Trade	**334.2**	**327.6**	**279.4**	**278.2**	**258.4**	**168.6**	**160.4**	**147.9**	**73.9**	**81.1**
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)	4413.9	6468.6	5579.8	5474.0	4510.4	3283.6	3090.6	4605.1	4020.7	4444.8
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11485.6**	**11379.8**	**9361.6**	**8134.8**	**7941.9**	**4605.1**	**4020.7**	**4444.8**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	10.7	5.8	17.9	19.1	0.0	12.1	12.1
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**	**63.8**	**65.0**	**30.6**	**42.7**	**42.7**
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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Production										
Dry Gas Production[1]	18.67	21.40	20.89	20.84	23.43	23.96	24.90	29.47	30.54	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**	**4.69**	**4.70**	**4.69**	**5.00**	**6.50**	**6.60**	**5.82**	**7.88**	**7.97**
Canada	3.29	4.48	4.49	4.48	4.72	4.89	4.97	5.43	5.72	5.73
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	0.32	0.32	-0.40	0.36	0.36
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	1.30	1.31	0.79	1.80	1.88
Total Supply	**22.15**	**26.20**	**25.70**	**25.65**	**28.49**	**30.52**	**31.56**	**35.35**	**38.48**	**38.46**
Consumption by Sector										
Residential	4.75	5.42	5.45	5.45	5.46	5.42	5.37	6.07	6.06	6.05
Commercial	3.06	3.88	3.90	3.91	4.06	4.04	4.00	4.32	4.70	4.82
Industrial[3]	8.31	8.81	8.82	8.82	9.48	9.53	9.45	10.53	11.11	11.12
Electric Generators[4]	3.64	5.43	4.92	4.86	6.81	8.81	9.93	11.19	13.25	13.12
Lease and Plant Fuel[5]	1.23	1.38	1.35	1.35	1.50	1.53	1.57	1.87	1.91	1.91
Pipeline Fuel	0.64	0.81	0.80	0.79	0.88	0.90	0.94	1.07	1.12	1.12
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.65**	**25.79**	**25.29**	**25.23**	**28.29**	**30.32**	**31.35**	**35.20**	**38.31**	**38.29**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.42**	**0.20**	**0.20**	**0.21**	**0.14**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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, M2NM9008.D060801A, M2NM7B08.D060901A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G8. 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	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.80	2.79	2.87	3.24	3.50	3.22	3.69	3.80
Average Import Price	2.29	2.95	2.93	2.93	2.64	2.90	3.01	2.72	3.02	3.09
Average[2]	**2.11**	**2.96**	**2.83**	**2.82**	**2.82**	**3.17**	**3.40**	**3.13**	**3.55**	**3.65**
Delivered Prices										
Residential	6.69	7.31	7.17	7.16	6.91	7.26	7.49	6.83	7.26	7.36
Commercial	5.49	5.70	5.57	5.56	5.82	6.17	6.39	5.93	6.34	6.45
Industrial[3]	2.87	3.74	3.60	3.59	3.59	3.96	4.21	3.95	4.40	4.51
Electric Generators[4]	2.63	3.50	3.48	3.46	3.32	3.97	4.29	3.78	4.48	4.60
Transportation[5]	7.21	7.48	7.34	7.33	7.40	7.77	7.99	7.61	8.01	8.11
Average[6]	**4.15**	**4.84**	**4.76**	**4.75**	**4.59**	**4.94**	**5.17**	**4.72**	**5.21**	**5.32**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.35	4.35	4.08	4.09	4.09	3.70	3.71	3.71
Commercial	3.37	2.74	2.75	2.74	2.99	3.00	3.00	2.81	2.80	2.80
Industrial[3]	0.76	0.78	0.78	0.78	0.77	0.79	0.81	0.82	0.85	0.86
Electric Generators[4]	0.52	0.54	0.65	0.65	0.49	0.80	0.89	0.65	0.93	0.95
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.60	4.60	4.48	4.46	4.46
Average[6]	**2.04**	**1.88**	**1.93**	**1.94**	**1.76**	**1.78**	**1.78**	**1.59**	**1.66**	**1.67**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.69	23.69	22.30	22.19	22.00	22.48	22.46	22.48
Commercial	10.32	10.63	10.72	10.72	12.16	12.12	11.99	12.12	13.15	13.49
Industrial[3]	6.28	6.86	6.84	6.83	7.26	7.53	7.69	8.65	9.49	9.57
Electric Generators[4]	1.88	2.94	3.20	3.14	3.36	7.08	8.86	7.24	12.39	12.49
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.40	0.40	0.68	0.66	0.65
Total	**40.32**	**44.25**	**44.69**	**44.62**	**45.49**	**49.32**	**50.95**	**51.18**	**58.15**	**58.67**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	16.49	**21.43**	**20.56**	**21.43**	**20.73**	**20.77**	**20.79**	**21.47**	**21.41**	**21.42**
Production (million barrels per day)[2]										
U.S. Total	5.88	**5.66**	**5.68**	**5.67**	**5.32**	**5.28**	**5.30**	**5.25**	**5.31**	**5.38**
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.51	2.52	2.75	2.80	2.83
Conventional	2.59	2.18	2.18	2.17	1.81	1.82	1.83	1.98	2.03	2.07
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.70	0.69	0.76	0.76	0.76
Lower 48 Offshore	1.56	2.06	2.08	2.07	2.16	2.12	2.13	1.87	1.87	1.91
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**	**15.75**	**15.75**	**15.76**	**14.55**	**14.48**	**14.54**	**14.11**	**14.26**	**14.37**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	2.08	**2.96**	**2.80**	**2.79**	**2.87**	**3.24**	**3.50**	**3.22**	**3.69**	**3.80**
Production (trillion cubic feet)[3]										
U.S. Total	18.67	**21.40**	**20.89**	**20.84**	**23.43**	**23.96**	**24.90**	**29.47**	**30.54**	**30.44**
Lower 48 Onshore	12.83	14.46	14.00	13.96	16.71	16.84	17.66	21.31	22.42	22.37
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.33	1.33	1.39	1.42	1.44
Non-Associated	11.03	12.95	12.48	12.45	15.39	15.52	16.33	19.91	21.00	20.93
Conventional	6.64	7.67	7.43	7.42	7.93	8.01	8.53	11.14	11.41	11.27
Unconventional	4.39	5.27	5.05	5.02	7.45	7.51	7.80	8.78	9.60	9.67
Lower 48 Offshore	5.43	6.47	6.43	6.42	6.22	6.62	6.75	7.59	7.56	7.51
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	5.41	5.37	5.35	5.13	5.53	5.66	6.56	6.52	6.47
Alaska	0.42	0.47	0.47	0.47	0.50	0.50	0.50	0.57	0.56	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**167.88**	**169.73**	**170.08**	**185.55**	**184.66**	**185.37**	**200.71**	**200.26**	**208.77**
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	**28.87**	**27.94**	**27.85**	**29.86**	**31.86**	**33.93**	**39.36**	**44.00**	**46.75**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Production[1]										
Appalachia	433	426	418	419	421	306	275	396	240	234
Interior	185	182	175	179	180	113	108	161	94	87
West	486	624	572	568	694	435	341	783	387	320
East of the Mississippi	559	561	548	553	557	388	355	524	311	300
West of the Mississippi	544	672	617	613	738	464	369	817	410	341
Total	**1103**	**1233**	**1165**	**1166**	**1295**	**853**	**724**	**1340**	**721**	**641**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	60	59	56	62	59
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-51**	**-50**	**-36**	**-54**	**-50**
Total Supply[2]	**1054**	**1189**	**1117**	**1118**	**1254**	**802**	**674**	**1304**	**667**	**590**
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	86	84	84
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1005	1008	1145	694	567	1196	554	485
Total	**1032**	**1189**	**1117**	**1120**	**1256**	**803**	**677**	**1306**	**663**	**593**
Discrepancy and Stock Change[5]	**21**	**-1**	**0**	**-2**	**-2**	**-2**	**-3**	**-2**	**5**	**-3**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	14.96	15.11	14.08	13.42	13.43	12.87	11.90	12.16
(1999 dollars per million Btu)	0.82	0.73	0.72	0.73	0.69	0.64	0.64	0.64	0.57	0.58
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.49	29.64	28.61	26.68	26.12	26.50	23.80	23.54
Coke Plants	44.28	42.39	42.46	42.52	41.36	41.41	41.45	38.52	38.60	38.67
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	21.77	21.80	21.28	19.22	18.35	19.41	16.81	16.47
(1999 dollars per million Btu)	1.21	1.14	1.07	1.07	1.06	0.95	0.91	0.98	0.85	0.82
Average	**25.77**	**23.78**	**22.80**	**22.84**	**22.13**	**20.61**	**20.07**	**20.15**	**18.33**	**18.18**
Exports[7]	37.44	36.39	36.34	36.45	35.66	34.55	34.26	33.09	31.17	31.38

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Btu = British thermal unit.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.34	79.59	79.38	80.69	80.85	79.38	80.69	80.85
Geothermal[2]	2.87	3.43	6.78	7.25	4.93	10.20	10.48	4.95	10.50	10.80
Municipal Solid Waste[3]	2.61	2.96	3.24	3.24	3.42	4.24	4.42	3.93	4.82	4.94
Wood and Other Biomass[4]	1.57	1.75	1.84	1.95	2.12	2.50	3.48	2.45	3.52	6.55
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	7.04	7.10	7.52	8.42	9.50	7.76	12.40	19.13
Total	**88.83**	**94.75**	**98.68**	**99.56**	**97.98**	**106.65**	**109.33**	**99.49**	**112.94**	**123.30**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.47	302.22	301.13	305.52	306.02	300.07	304.39	304.87
Geothermal[2]	13.21	18.34	46.00	49.92	30.94	74.42	76.62	31.16	76.96	79.35
Municipal Solid Waste[3]	18.12	20.68	22.94	22.94	23.88	30.26	31.66	27.76	34.67	35.68
Wood and Other Biomass[4]	9.02	14.94	30.01	26.92	21.30	79.00	72.81	19.78	72.50	86.31
Dedicated Plants	7.73	9.16	9.78	10.48	11.36	13.96	20.51	13.82	21.02	41.23
Cofiring	1.29	5.78	20.23	16.44	9.94	65.04	52.31	5.95	51.49	45.08
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	16.64	16.79	18.16	20.66	23.66	18.83	33.63	54.99
Total	**355.43**	**372.61**	**418.21**	**419.95**	**397.03**	**511.47**	**512.39**	**400.32**	**524.87**	**563.93**
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	5.17	5.19	5.19	6.06	6.07	6.06	7.54	7.56	7.55
Total	**5.35**	**5.87**	**5.89**	**5.89**	**6.76**	**6.77**	**6.76**	**8.24**	**8.26**	**8.25**
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	29.92	30.02	30.02	35.01	35.00	34.92	43.52	43.53	43.46
Total	**31.12**	**33.97**	**34.06**	**34.06**	**39.05**	**39.04**	**38.97**	**47.57**	**47.57**	**47.51**
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	0.36	0.36
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.35**	**1.35**
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	0.77	0.78
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.18**	**5.20**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	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**	**2.42**	**2.41**	**2.41**	**2.64**	**2.63**	**2.63**	**3.08**	**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	2.23	2.22	2.22	2.46	2.44	2.44	2.90	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.22**	**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**	**4.19**	**5.21**	**5.31**	**4.73**	**6.80**	**6.86**	**4.78**	**7.02**	**7.45**
Conventional Hydroelectric	3.19	3.10	3.10	3.11	3.10	3.14	3.15	3.08	3.13	3.14
Geothermal	0.28	0.44	1.28	1.40	0.85	2.19	2.26	0.85	2.27	2.36
Municipal Solid Waste[6]	0.25	0.28	0.31	0.31	0.32	0.41	0.43	0.38	0.47	0.49
Biomass	0.12	0.18	0.33	0.30	0.26	0.83	0.76	0.25	0.77	0.88
Dedicated Plants	0.10	0.11	0.11	0.12	0.14	0.15	0.21	0.17	0.22	0.42
Cofiring	0.02	0.07	0.22	0.18	0.12	0.68	0.54	0.07	0.54	0.46
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	0.21	0.24	0.19	0.35	0.57
Total Marketed Renewable Energy	**6.64**	**7.31**	**8.31**	**8.41**	**8.10**	**10.16**	**10.21**	**8.62**	**10.85**	**11.28**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**	**0.03**
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	0.18	0.18	0.20	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**	**0.22**	**0.22**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.6	23.2	23.6	23.7
Natural Gas	69.5	80.2	80.6	80.6	80.8	80.2	79.5	89.8	89.6	89.5
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	193.4	227.1	210.5	210.9	242.6	170.5	153.0	275.6	174.1	162.2
Total	**290.1**	**335.0**	**318.8**	**319.2**	**349.2**	**276.6**	**258.4**	**389.8**	**288.5**	**276.6**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.1	12.2	12.1	12.2	12.7
Natural Gas	45.4	57.4	57.7	57.8	60.1	59.8	59.1	63.9	69.6	71.3
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	203.2	203.5	240.4	170.6	153.5	267.1	166.2	153.7
Total	**242.1**	**289.4**	**274.5**	**274.8**	**314.3**	**244.3**	**226.7**	**345.0**	**249.9**	**239.6**
Industrial[1]										
Petroleum	104.2	99.2	98.5	98.6	105.3	105.7	106.3	113.6	114.9	115.7
Natural Gas[2]	141.6	148.4	148.1	148.0	159.8	161.1	160.6	180.3	189.9	190.0
Coal	55.9	65.8	65.6	65.5	65.6	64.5	64.2	65.8	64.7	64.5
Electricity	178.8	193.6	179.4	179.7	204.1	143.8	130.3	226.4	132.7	122.7
Total	**480.4**	**507.0**	**491.6**	**491.8**	**534.8**	**475.1**	**461.4**	**586.1**	**502.2**	**492.9**
Transportation										
Petroleum[3]	485.8	556.3	554.3	554.3	607.2	603.3	602.3	704.2	700.7	700.2
Natural Gas[4]	9.5	12.8	12.5	12.5	14.4	14.6	15.1	18.1	18.8	18.7
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	4.1	4.1	5.8	4.4	4.0	7.9	5.4	5.1
Total[3]	**498.2**	**573.6**	**571.0**	**571.0**	**627.5**	**622.4**	**621.5**	**730.2**	**725.0**	**724.0**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	691.2	691.2	749.0	745.6	745.4	853.1	851.5	852.2
Natural Gas	266.0	298.8	299.0	299.0	315.1	315.6	314.4	352.0	367.8	369.5
Coal	58.8	68.8	68.5	68.5	68.8	67.6	67.4	69.0	67.9	67.6
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	643.6	597.2	598.2	692.8	489.3	440.7	777.0	478.3	443.7
Total[3]	**1510.8**	**1705.0**	**1655.9**	**1656.9**	**1825.7**	**1618.3**	**1568.0**	**2051.2**	**1765.6**	**1733.1**
Electric Generators[6]										
Petroleum	20.0	9.4	3.8	3.7	5.8	2.1	1.7	5.2	2.1	2.4
Natural Gas	45.8	79.6	72.2	71.3	100.0	129.3	145.7	164.1	194.5	192.6
Coal	490.5	554.6	521.2	523.2	587.0	357.9	293.3	607.7	281.8	248.7
Total	**556.3**	**643.6**	**597.2**	**598.2**	**692.8**	**489.3**	**440.7**	**777.0**	**478.3**	**443.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	695.0	694.9	754.8	747.7	747.1	858.3	853.6	854.6
Natural Gas	311.8	378.4	371.1	370.3	415.0	445.0	460.1	516.2	562.3	562.1
Coal	549.3	623.3	589.8	591.7	655.8	425.5	360.7	676.7	349.7	316.3
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**	**1705.0**	**1655.9**	**1656.9**	**1825.7**	**1618.3**	**1568.0**	**2051.2**	**1765.6**	**1733.1**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.7**	**5.8**	**6.1**	**5.4**	**5.2**	**6.3**	**5.4**	**5.3**

[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 20 to 25 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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Table G14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.06	3.05	4.34	1.65	1.42	4.49	1.38	1.31
Sulfur Dioxide (million tons)	13.71	10.38	8.55	8.55	9.70	4.52	4.02	8.95	3.27	3.27
Mercury (tons)	43.60	45.24	40.26	39.84	45.60	25.29	20.67	45.07	18.76	17.54
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	597.20	598.20	692.78	489.32	440.73	776.99	478.30	443.71
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	1565	1445	4391	0	0	5037	0	0
Sulfur Dioxide (1999 dollars per ton)	0	190	177	167	187	431	246	241	436	259
Mercury (million 1999 dollars per ton)	0	0	0	0	0	0	0	0	0	0
Carbon Dioxide((1999 dollars per ton carbon equivalent)	0	0	27	27	0	112	142	0	143	154
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	14.5	18.5	7.1	14.5	18.5	14.8	14.5	18.5
Combustion	0.0	39.9	51.7	54.9	42.1	57.6	60.5	46.1	59.2	60.5
SCR Post-combustion	0.0	92.8	61.3	59.8	92.9	100.8	87.0	93.0	100.8	87.0
SNCR Post-combustion	0.0	25.2	17.2	23.5	26.3	72.1	83.8	43.4	72.4	84.0
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	578	569	642	454	346	721	391	320
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	407	409	464	278	254	440	223	213
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	180	187	188	121	124	179	107	108

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
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 M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A.

Appendix H

Tables for Integrated Cases With Four Emissions Caps, Including CO_2 Emissions at the 1990 Level

Table H1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.01	12.02	11.27	11.19	11.23	11.12	11.34	11.08
Natural Gas Plant Liquids	2.62	3.12	3.04	3.00	3.37	3.56	3.46	4.16	4.30	3.95
Dry Natural Gas	19.16	21.95	21.40	21.11	24.04	25.43	24.69	30.24	31.28	28.72
Coal	23.08	25.45	24.25	24.50	26.55	17.02	18.35	27.16	14.79	17.58
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	6.95
Renewable Energy[1]	6.53	7.13	8.16	8.84	7.90	9.40	12.61	8.42	10.25	17.47
Other[2]	1.65	0.35	0.58	0.58	0.31	0.30	0.55	0.33	0.33	0.33
Total	**73.29**	**77.88**	**77.35**	**77.97**	**81.19**	**74.81**	**78.81**	**87.97**	**79.57**	**86.08**
Imports										
Crude Oil[3]	18.96	21.42	21.40	21.38	22.38	22.54	22.42	25.82	25.72	25.92
Petroleum Products[4]	4.14	6.28	5.83	5.88	8.65	8.08	8.03	10.80	10.33	10.65
Natural Gas	3.63	5.13	5.13	5.00	5.55	6.85	5.75	6.59	8.18	6.53
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.88	0.88	0.96	0.81	0.81
Total	**27.37**	**33.93**	**33.37**	**33.28**	**37.54**	**38.34**	**37.09**	**44.18**	**45.04**	**43.92**
Exports										
Petroleum[6]	1.98	1.73	1.75	1.75	1.69	1.72	1.71	1.85	1.81	1.86
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.12	0.43	0.63	0.12	0.63
Coal	1.48	1.51	1.51	1.51	1.45	1.50	1.52	1.41	1.55	1.58
Total	**3.62**	**3.57**	**3.58**	**3.58**	**3.58**	**3.34**	**3.65**	**3.89**	**3.47**	**4.08**
Discrepancy[7]	**0.69**	**0.43**	**0.52**	**0.56**	**0.04**	**0.10**	**0.15**	**0.11**	**0.08**	**0.12**
Consumption										
Petroleum Products[8]	38.02	41.34	40.91	40.92	44.44	44.10	44.03	50.45	50.27	50.10
Natural Gas	22.21	26.44	25.89	25.47	29.00	31.97	29.84	36.06	39.17	34.48
Coal	21.42	24.39	23.14	23.35	25.64	15.83	17.18	26.42	13.69	16.42
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	6.95
Renewable Energy[1]	6.54	7.13	8.16	8.85	7.91	9.40	12.62	8.43	10.25	17.48
Other[9]	0.35	0.61	0.61	0.61	0.38	0.51	0.51	0.25	0.38	0.38
Total	**96.33**	**107.81**	**106.62**	**107.10**	**115.11**	**109.72**	**112.10**	**128.16**	**121.05**	**125.80**
Net Imports - Petroleum	**21.12**	**25.96**	**25.48**	**25.51**	**29.34**	**28.90**	**28.75**	**34.78**	**34.24**	**34.71**
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	2.96	2.79	2.79	2.87	3.40	2.97	3.22	3.72	3.09
Coal Minemouth Price (dollars per ton)	17.17	15.05	15.33	15.09	14.08	15.09	15.57	12.87	13.66	14.22
Average Electric Price (cents per Kwh)	6.6	6.4	6.8	6.7	6.1	7.9	8.0	6.2	8.4	7.8

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.81	0.81	0.76	0.77	0.77
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.41	0.41
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.25	1.24
Natural Gas	4.88	5.57	5.60	5.60	5.61	5.54	5.62	6.23	6.20	6.36
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	0.44	0.43	0.44
Electricity	3.91	4.57	4.49	4.50	4.95	4.64	4.62	5.79	5.33	5.43
Delivered Energy	**10.66**	**12.01**	**11.96**	**11.98**	**12.34**	**11.95**	**12.02**	**13.74**	**13.26**	**13.52**
Electricity Related Losses	8.44	9.67	9.37	9.54	10.10	8.59	9.36	10.85	8.84	10.50
Total	**19.10**	**21.68**	**21.34**	**21.51**	**22.44**	**20.54**	**21.38**	**24.59**	**22.10**	**24.02**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.37	0.39	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	0.60	0.61	0.61	0.62	0.62	0.62	0.62	0.63	0.62
Natural Gas	3.14	3.99	4.01	4.01	4.17	4.12	4.20	4.44	4.75	4.90
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	4.39	4.33	4.35	4.91	4.63	4.63	5.62	5.11	5.18
Delivered Energy	**7.55**	**9.13**	**9.10**	**9.12**	**9.85**	**9.53**	**9.60**	**10.83**	**10.65**	**10.86**
Electricity Related Losses	7.91	9.30	9.04	9.20	10.01	8.58	9.37	10.51	8.46	10.02
Total	**15.46**	**18.44**	**18.14**	**18.32**	**19.86**	**18.11**	**18.96**	**21.34**	**19.11**	**20.89**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.21	1.21	1.31	1.29	1.29	1.49	1.48	1.47
Liquefied Petroleum Gas	2.32	2.45	2.42	2.42	2.53	2.55	2.50	2.85	2.90	2.80
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.26	0.26	0.28	0.29	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.42	4.41	4.71	4.72	4.70	5.02	5.09	5.04
Petroleum Subtotal	9.45	9.86	9.80	9.79	10.57	10.60	10.51	11.63	11.74	11.56
Natural Gas[6]	9.80	10.46	10.44	10.43	11.27	11.32	11.45	12.73	13.23	13.38
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	1.81	1.80	1.81	1.83	1.74	1.77	1.87	1.85	1.88
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.50	2.53	2.60	2.56	2.60
Renewable Energy[7]	2.15	2.42	2.41	2.41	2.64	2.63	2.63	3.08	3.08	3.08
Electricity	3.61	3.90	3.83	3.84	4.17	3.90	3.88	4.76	4.10	4.08
Delivered Energy	**27.56**	**29.23**	**29.06**	**29.05**	**31.24**	**30.95**	**30.99**	**34.80**	**34.71**	**34.69**
Electricity Related Losses	7.80	8.25	7.99	8.13	8.50	7.23	7.85	8.91	6.79	7.89
Total	**35.36**	**37.48**	**37.05**	**37.18**	**39.74**	**38.18**	**38.85**	**43.71**	**41.51**	**42.58**

Table H2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections 2005 Reference	2005 NO_x, SO_2, CO_2 1990, Hg	2005 All CO_2 1990	2010 Reference	2010 NO_x, SO_2, CO_2 1990, Hg	2010 All CO_2 1990	2020 Reference	2020 NO_x, SO_2, CO_2 1990, Hg	2020 All CO_2 1990
Transportation										
Distillate Fuel	5.13	6.28	6.23	6.23	7.00	6.88	6.89	8.22	8.10	8.11
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.49	5.97	5.96	5.97
Motor Gasoline[2]	15.92	17.67	17.64	17.64	18.97	18.90	18.90	21.26	21.20	21.22
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	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	0.30	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.92	28.93	31.68	31.47	31.48	36.73	36.54	36.56
Pipeline Fuel Natural Gas	0.66	0.83	0.82	0.80	0.91	0.95	0.94	1.10	1.14	1.06
Compressed Natural Gas	0.02	0.06	0.05	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	0.01	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**	**30.03**	**29.91**	**29.90**	**32.83**	**32.67**	**32.67**	**38.20**	**38.05**	**37.99**
Electricity Related Losses	0.13	0.19	0.18	0.19	0.24	0.22	0.24	0.31	0.27	0.32
Total	**26.41**	**30.22**	**30.09**	**30.09**	**33.07**	**32.89**	**32.91**	**38.51**	**38.33**	**38.31**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.68	8.69	9.49	9.37	9.36	10.85	10.75	10.71
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.49	5.97	5.96	5.97
Liquefied Petroleum Gas	2.88	3.02	3.00	2.99	3.08	3.11	3.06	3.41	3.47	3.36
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.17	19.17	21.57	21.51	21.53
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.21	1.20	1.24	1.24	1.23
Other Petroleum[12]	4.53	4.71	4.69	4.68	4.99	5.01	4.98	5.35	5.42	5.37
Petroleum Subtotal	37.01	40.90	40.73	40.73	44.16	43.99	43.91	50.21	50.17	49.99
Natural Gas[6]	18.50	20.91	20.92	20.90	22.05	22.01	22.30	24.66	25.47	25.85
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.95	1.87	1.89	2.00	1.97	2.00
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.70	2.70	2.71	2.62	2.65	2.72	2.69	2.72
Renewable Energy[13]	2.65	2.94	2.93	2.93	3.18	3.17	3.17	3.65	3.64	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	12.95	12.74	12.78	14.15	13.29	13.25	16.34	14.70	14.85
Delivered Energy	**72.05**	**80.41**	**80.03**	**80.05**	**86.27**	**85.10**	**85.28**	**97.57**	**96.68**	**97.06**
Electricity Related Losses	24.29	27.40	26.59	27.05	28.84	24.62	26.82	30.58	24.37	28.74
Total	**96.33**	**107.81**	**106.62**	**107.10**	**115.11**	**109.72**	**112.10**	**128.16**	**121.05**	**125.80**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.03	0.03	0.06	0.02	0.02	0.06	0.02	0.02
Residual Fuel	0.96	0.38	0.15	0.16	0.22	0.09	0.11	0.19	0.08	0.09
Petroleum Subtotal	1.02	0.44	0.19	0.19	0.28	0.10	0.13	0.25	0.10	0.11
Natural Gas	3.71	5.53	4.97	4.57	6.94	9.96	7.55	11.40	13.70	8.63
Steam Coal	18.77	21.68	20.44	20.65	22.93	13.21	14.53	23.70	11.01	13.70
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	6.95
Renewable Energy[15]	3.88	4.19	5.23	5.92	4.73	6.23	9.45	4.78	6.62	13.84
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.50	0.50	0.24	0.37	0.37
Total	**35.52**	**40.35**	**39.34**	**39.83**	**42.99**	**37.91**	**40.07**	**46.92**	**39.07**	**43.59**

Table H2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.71	8.72	9.54	9.38	9.38	10.91	10.76	10.73
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.49	4.49	5.97	5.96	5.97
Liquefied Petroleum Gas	2.88	3.02	3.00	2.99	3.08	3.11	3.06	3.41	3.47	3.36
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.17	19.17	21.57	21.51	21.53
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	2.01	1.48	1.26	1.26	1.42	1.29	1.31	1.42	1.33	1.32
Other Petroleum[12]	4.53	4.71	4.69	4.68	4.99	5.01	4.98	5.35	5.42	5.37
Petroleum Subtotal	38.02	41.34	40.91	40.92	44.44	44.10	44.03	50.45	50.27	50.10
Natural Gas	22.21	26.44	25.89	25.47	29.00	31.97	29.84	36.06	39.17	34.48
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	22.36	22.57	24.88	15.07	16.43	25.70	12.98	15.70
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	23.14	23.35	25.64	15.83	17.18	26.42	13.69	16.42
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	6.95
Renewable Energy[17]	6.54	7.13	8.16	8.85	7.91	9.40	12.62	8.43	10.26	17.48
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	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	0.50	0.50	0.24	0.37	0.37
Total	**96.33**	**107.81**	**106.62**	**107.10**	**115.11**	**109.72**	**112.10**	**128.16**	**121.05**	**125.80**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.03	80.05	86.27	85.10	85.28	97.57	96.68	97.06
Total Energy Use	96.33	107.81	106.62	107.10	115.11	109.72	112.10	128.16	121.05	125.80
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	10960	10902	10906	12667	12620	12621	16515	16523	16518
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1656.7	1656.2	1825.7	1609.4	1612.0	2051.2	1764.4	1763.2

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Residential	**13.10**	**13.27**	**13.60**	**13.50**	**13.46**	**15.56**	**15.41**	**13.77**	**16.16**	**15.23**
Primary Energy[1]	6.71	7.49	7.37	7.36	7.18	7.57	7.26	7.08	7.44	6.98
Petroleum Products[2]	7.55	9.20	9.14	9.14	9.37	9.42	9.34	9.47	9.41	9.51
Distillate Fuel	6.27	7.45	7.37	7.37	7.57	7.56	7.57	7.78	7.74	7.76
Liquefied Petroleum Gas	10.36	12.60	12.58	12.59	12.86	13.08	12.79	12.75	12.62	12.89
Natural Gas	6.52	7.11	6.98	6.97	6.72	7.19	6.83	6.65	7.09	6.53
Electricity	23.47	22.16	23.37	23.12	22.30	27.44	27.70	22.44	28.42	26.85
Commercial	**13.18**	**12.70**	**13.27**	**13.12**	**12.25**	**15.20**	**15.09**	**12.69**	**15.76**	**14.53**
Primary Energy[1]	5.22	5.57	5.45	5.44	5.68	6.08	5.77	5.79	6.14	5.67
Petroleum Products[2]	4.99	6.13	6.07	6.07	6.29	6.28	6.26	6.40	6.32	6.40
Distillate Fuel	4.37	5.24	5.16	5.16	5.36	5.32	5.34	5.53	5.48	5.51
Residual Fuel	2.63	3.65	3.61	3.61	3.71	3.69	3.69	3.86	3.84	3.84
Natural Gas[3]	5.34	5.55	5.42	5.41	5.66	6.13	5.77	5.78	6.20	5.64
Electricity	21.45	20.26	21.72	21.39	18.76	24.68	24.92	19.00	26.04	24.10
Industrial[4]	**5.27**	**5.76**	**5.82**	**5.78**	**5.67**	**6.48**	**6.29**	**5.90**	**6.66**	**6.21**
Primary Energy	3.91	4.47	4.38	4.37	4.49	4.73	4.49	4.68	4.86	4.57
Petroleum Products[2]	5.54	6.00	5.93	5.94	6.13	6.16	6.04	6.16	6.11	6.15
Distillate Fuel	4.65	5.40	5.33	5.32	5.56	5.50	5.52	5.73	5.69	5.71
Liquefied Petroleum Gas	8.50	7.74	7.70	7.71	7.88	8.11	7.74	7.76	7.70	7.83
Residual Fuel	2.78	3.38	3.35	3.35	3.44	3.42	3.42	3.59	3.58	3.58
Natural Gas[5]	2.79	3.64	3.50	3.49	3.50	4.00	3.61	3.85	4.32	3.70
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.55	1.56	1.44	1.44	1.45
Steam Coal	1.43	1.35	1.35	1.35	1.31	1.20	1.22	1.21	1.10	1.13
Electricity	13.00	12.80	13.84	13.60	12.08	16.63	16.88	12.22	17.82	16.41
Transportation	**8.30**	**9.39**	**9.34**	**9.34**	**9.69**	**9.72**	**9.72**	**9.20**	**9.23**	**9.19**
Primary Energy	8.29	9.38	9.33	9.32	9.68	9.70	9.69	9.18	9.20	9.16
Petroleum Products[2]	8.28	9.37	9.32	9.32	9.67	9.69	9.69	9.18	9.19	9.16
Distillate Fuel[6]	8.22	8.98	8.90	8.89	8.95	8.95	8.95	8.83	8.81	8.83
Jet Fuel[7]	4.70	5.29	5.23	5.23	5.49	5.48	5.49	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.76	10.76	11.31	11.35	11.33	10.60	10.63	10.56
Residual Fuel	2.46	3.11	3.10	3.10	3.18	3.17	3.17	3.33	3.32	3.32
Liquid Petroleum Gas[9]	12.87	14.07	14.03	14.04	14.07	14.32	13.97	13.70	13.63	13.81
Natural Gas[10]	7.02	7.28	7.14	7.12	7.21	7.69	7.32	7.41	7.83	7.26
Ethanol (E85)[11]	14.42	19.21	19.18	19.18	19.16	19.23	19.19	19.36	19.42	19.31
Methanol (M85)[12]	10.38	13.13	12.99	12.98	13.83	13.83	13.83	14.35	14.35	14.35
Electricity	15.59	14.52	15.06	15.06	13.62	16.32	16.99	13.22	16.28	15.98
Average End-Use Energy	**8.49**	**9.17**	**9.29**	**9.24**	**9.22**	**10.14**	**10.04**	**9.21**	**10.15**	**9.73**
Primary Energy	6.31	7.19	7.11	7.11	7.35	7.50	7.36	7.23	7.33	7.13
Electricity	19.41	18.65	19.89	19.62	17.99	23.20	23.46	18.19	24.50	22.90
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.54	1.51	1.59	2.33	1.91	1.88	2.86	2.01
Petroleum Products	2.49	3.61	3.82	3.80	3.90	4.24	4.09	4.17	4.49	4.47
Distillate Fuel	4.04	4.72	4.72	4.74	4.87	4.91	4.90	5.06	5.14	5.15
Residual Fuel	2.40	3.42	3.63	3.62	3.65	4.11	3.94	3.89	4.36	4.33
Natural Gas	2.58	3.44	3.40	3.36	3.26	4.11	3.60	3.71	4.45	3.69
Steam Coal	1.21	1.14	1.07	1.08	1.06	0.97	1.01	0.98	0.87	0.94

Table H3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.51	8.51	8.81	8.85	8.81	8.49	8.50	8.49
Distillate Fuel	7.25	8.14	8.08	8.07	8.20	8.20	8.21	8.20	8.18	8.21
Jet Fuel	4.70	5.29	5.23	5.23	5.49	5.48	5.49	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.60	8.61	8.74	8.96	8.63	8.54	8.47	8.64
Motor Gasoline[8]	9.45	10.80	10.76	10.76	11.31	11.35	11.33	10.60	10.63	10.56
Residual Fuel	2.47	3.25	3.23	3.23	3.33	3.32	3.32	3.49	3.48	3.48
Natural Gas	4.05	4.72	4.63	4.64	4.47	4.95	4.62	4.60	5.11	4.58
Coal	1.23	1.16	1.10	1.10	1.08	1.00	1.04	1.00	0.90	0.96
Ethanol (E85)[11]	14.42	19.21	19.18	19.18	19.16	19.23	19.19	19.36	19.42	19.31
Methanol (M85)[12]	10.38	13.13	12.99	12.98	13.83	13.83	13.83	14.35	14.35	14.35
Electricity	19.41	18.65	19.89	19.62	17.99	23.20	23.46	18.19	24.50	22.90
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	156.93	156.07	160.41	179.31	178.65	183.27	207.36	199.21
Commercial	98.42	114.97	119.64	118.46	119.69	143.56	143.50	136.41	166.49	156.59
Industrial	111.66	127.05	128.08	127.21	133.28	151.77	148.13	154.57	175.38	163.45
Transportation	212.64	273.84	271.38	271.42	308.81	307.80	307.71	340.45	339.80	338.66
Total Non-Renewable Expenditures	556.99	669.69	676.04	673.16	722.19	782.44	777.98	814.69	889.03	857.91
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.63	0.85	0.85	0.84
Total Expenditures	**557.13**	**670.11**	**676.45**	**673.58**	**722.82**	**783.08**	**778.61**	**815.54**	**889.88**	**858.75**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections 2005 Reference	2005 NO_x, SO_2, CO_2 1990, Hg	2005 All CO_2 1990	2010 Reference	2010 NO_x, SO_2, CO_2 1990, Hg	2010 All CO_2 1990	2020 Reference	2020 NO_x, SO_2, CO_2 1990, Hg	2020 All CO_2 1990
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	1992	2012	2245	1290	1425	2315	1082	1345
Petroleum	94	43	19	19	28	11	14	25	11	12
Natural Gas[2]	359	583	618	561	825	1421	1026	1495	2014	1206
Nuclear Power	730	740	740	740	725	741	741	613	681	651
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	417	465	397	484	723	400	513	1131
Total	**3369**	**3844**	**3785**	**3796**	**4219**	**3946**	**3927**	**4847**	**4301**	**4344**
Non-Utility Generation for Own Use	16	17	21	21	17	20	20	17	20	20
Distributed Generation	0	0	0	0	1	1	1	5	1	2
Cogenerators[4]										
Coal	47	53	52	53	52	42	45	52	41	45
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	207	237	243	241	261	313	319	318	570	578
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	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**	**345**	**350**	**348**	**373**	**417**	**425**	**441**	**683**	**695**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	170	171	180	177	182	208	258	264
Generation for Own Use	156	178	185	182	198	245	248	238	430	436
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**47**	**47**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1145	1339	1316	1320	1452	1359	1355	1698	1563	1591
Commercial	1073	1288	1270	1274	1439	1358	1356	1646	1496	1519
Industrial	1058	1142	1122	1125	1222	1144	1137	1395	1201	1195
Transportation	17	26	26	26	35	34	34	49	48	48
Total	**3294**	**3794**	**3735**	**3745**	**4147**	**3896**	**3882**	**4788**	**4309**	**4354**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	8.0	7.9	7.6	9.4	9.5	7.7	9.7	9.2
Commercial	7.3	6.9	7.4	7.3	6.4	8.4	8.5	6.5	8.9	8.2
Industrial	4.4	4.4	4.7	4.6	4.1	5.7	5.8	4.2	6.1	5.6
Transportation	5.3	5.0	5.1	5.1	4.6	5.6	5.8	4.5	5.6	5.5
All Sectors Average	**6.6**	**6.4**	**6.8**	**6.7**	**6.1**	**7.9**	**8.0**	**6.2**	**8.4**	**7.8**
Prices by Service Category[9] (1999 cents per kwh)										
Generation	4.1	3.8	4.2	4.1	3.5	5.1	5.2	3.6	5.7	5.1
Transmission	0.6	0.6	0.6	0.6	0.7	0.8	0.8	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.71	10.38	8.55	8.55	9.70	3.33	4.49	8.95	2.63	3.27
Nitrogen Oxide	5.45	4.30	3.08	3.02	4.34	1.51	1.66	4.49	1.34	1.53

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	302.8	302.8	318.6	270.2	273.5	318.5	248.9	262.6
Other Fossil Steam[3]	137.4	127.8	119.9	118.8	119.2	103.4	104.0	116.9	96.2	98.3
Combined Cycle	21.0	53.2	83.4	77.8	107.8	199.7	137.4	202.2	279.0	166.0
Combustion Turbine/Diesel	74.3	123.1	114.8	115.5	147.2	119.5	123.2	199.5	126.6	140.1
Nuclear Power	97.4	97.5	97.5	97.5	94.8	96.9	96.9	76.3	87.6	82.7
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	94.8	98.8	107.8	98.0	104.5	150.5	99.5	113.2	246.7
Distributed Generation[5]	0.0	0.7	0.6	0.5	2.5	1.2	1.3	11.5	3.3	4.7
Total	**743.4**	**820.4**	**837.2**	**840.2**	**907.8**	**915.1**	**906.5**	**1044.2**	**974.7**	**1020.9**
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	0.0	0.0	18.9	0.0	0.0	20.5	0.0	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	19.4	49.6	44.1	74.2	166.1	103.8	168.6	245.8	133.2
Combustion Turbine/Diesel	0.0	38.9	31.7	32.1	64.7	37.6	41.7	117.2	45.0	58.8
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	4.4	13.5	2.0	8.5	54.6	2.0	15.8	149.3
Distributed Generation[5]	0.0	0.7	0.6	0.5	2.5	1.2	1.3	11.5	3.3	4.7
Total	**0.0**	**60.6**	**86.3**	**90.2**	**162.2**	**213.4**	**201.3**	**319.8**	**309.9**	**346.1**
Cumulative Total Additions	**0.0**	**92.6**	**118.3**	**122.2**	**195.9**	**247.1**	**235.0**	**355.1**	**345.2**	**381.4**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	34.9	31.6	7.2	56.2	42.5
Other Fossil Steam[3]	0.0	9.9	17.8	18.8	18.4	34.2	33.6	20.7	41.4	39.3
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.1	0.2	0.2	0.6	1.0
Combustion Turbine/Diesel	0.0	4.4	5.3	5.1	6.0	6.5	6.9	6.3	6.8	7.2
Nuclear Power	0.0	0.0	0.0	0.0	2.6	0.6	0.6	21.2	9.8	14.8
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	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**16.7**	**25.5**	**26.5**	**32.8**	**76.5**	**73.1**	**55.6**	**115.1**	**105.0**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.1	7.5	8.6	6.8	7.5
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0
Natural Gas	34.6	39.9	40.9	40.6	43.3	51.0	51.5	51.4	86.4	87.5
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	8.2	8.3	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**	**59.2**	**60.2**	**59.9**	**63.3**	**69.5**	**70.4**	**73.2**	**106.5**	**108.2**
Cumulative Additions[6]	**0.0**	**6.8**	**7.8**	**7.5**	**10.9**	**17.1**	**18.0**	**20.7**	**54.1**	**55.7**

Table H5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
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	152.0	202.3	156.0	168.9	155.5	82.2	87.7	147.9	90.5	110.7
Gross Domestic Trade	**334.2**	**327.6**	**281.3**	**294.2**	**258.4**	**185.2**	**190.6**	**147.9**	**90.5**	**110.7**
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)	4413.9	6468.6	5674.5	6083.4	4510.4	3731.2	4136.7	4605.1	4777.4	5301.6
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11580.3**	**11989.2**	**9361.6**	**8582.4**	**8988.0**	**4605.1**	**4777.4**	**5301.6**
International Electricity Trade										
Firm Power Imports From Canada and	27.0	10.7	10.7	10.7	5.8	17.9	17.9	0.0	12.1	12.1
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**	**63.8**	**63.8**	**30.6**	**42.7**	**42.7**
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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Production										
Dry Gas Production[1]	18.67	21.40	20.86	20.58	23.43	24.78	24.07	29.47	30.49	27.99
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**	**4.69**	**4.69**	**4.56**	**5.00**	**6.58**	**5.20**	**5.82**	**7.88**	**5.76**
Canada	3.29	4.48	4.48	4.35	4.72	4.95	4.90	5.43	5.73	5.38
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	0.32	-0.25	-0.40	0.36	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	1.30	0.54	0.79	1.80	0.78
Total Supply	**22.15**	**26.20**	**25.66**	**25.25**	**28.49**	**31.42**	**29.32**	**35.35**	**38.42**	**33.80**
Consumption by Sector										
Residential	4.75	5.42	5.45	5.45	5.46	5.39	5.47	6.07	6.04	6.19
Commercial	3.06	3.88	3.91	3.91	4.06	4.01	4.09	4.32	4.62	4.78
Industrial[3]	8.31	8.81	8.82	8.82	9.48	9.46	9.62	10.53	10.97	11.23
Electric Generators[4]	3.64	5.43	4.87	4.49	6.81	9.78	7.41	11.19	13.45	8.46
Lease and Plant Fuel[5]	1.23	1.38	1.35	1.34	1.50	1.57	1.53	1.87	1.91	1.79
Pipeline Fuel	0.64	0.81	0.79	0.78	0.88	0.93	0.92	1.07	1.11	1.03
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.65**	**25.79**	**25.25**	**24.84**	**28.29**	**31.21**	**29.12**	**35.20**	**38.25**	**33.64**
Discrepancy[7]	**0.50**	**0.42**	**0.42**	**0.41**	**0.20**	**0.20**	**0.20**	**0.14**	**0.17**	**0.16**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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, M2P9008.D060801A, M2P9008R_X.D070601A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H8. 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	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.79	2.79	2.87	3.40	2.97	3.22	3.72	3.09
Average Import Price	2.29	2.95	2.93	2.89	2.64	2.93	2.77	2.72	3.03	2.77
Average[2]	**2.11**	**2.96**	**2.82**	**2.81**	**2.82**	**3.30**	**2.94**	**3.13**	**3.57**	**3.03**
Delivered Prices										
Residential	6.69	7.31	7.16	7.15	6.91	7.38	7.02	6.83	7.28	6.71
Commercial	5.49	5.70	5.56	5.55	5.82	6.29	5.93	5.93	6.37	5.80
Industrial[3]	2.87	3.74	3.60	3.58	3.59	4.11	3.71	3.95	4.43	3.80
Electric Generators[4]	2.63	3.50	3.46	3.43	3.32	4.19	3.67	3.78	4.53	3.76
Transportation[5]	7.21	7.48	7.33	7.32	7.40	7.90	7.52	7.61	8.04	7.46
Average[6]	**4.15**	**4.84**	**4.75**	**4.76**	**4.59**	**5.08**	**4.74**	**4.72**	**5.24**	**4.70**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.34	4.08	4.08	4.08	3.70	3.70	3.68
Commercial	3.37	2.74	2.74	2.74	2.99	2.99	2.99	2.81	2.79	2.77
Industrial[3]	0.76	0.78	0.78	0.77	0.77	0.81	0.77	0.82	0.86	0.77
Electric Generators[4]	0.52	0.54	0.64	0.62	0.49	0.88	0.74	0.65	0.96	0.73
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.60	4.58	4.48	4.46	4.43
Average[6]	**2.04**	**1.88**	**1.93**	**1.95**	**1.76**	**1.77**	**1.80**	**1.59**	**1.66**	**1.67**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.69	23.69	22.30	22.00	22.33	22.48	22.35	22.79
Commercial	10.32	10.63	10.72	10.72	12.16	11.98	12.24	12.12	12.90	13.22
Industrial[3]	6.28	6.86	6.83	6.83	7.26	7.63	7.45	8.65	9.42	8.61
Electric Generators[4]	1.88	2.94	3.14	2.78	3.36	8.65	5.47	7.24	12.91	6.16
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.40	0.40	0.68	0.66	0.67
Total	**40.32**	**44.25**	**44.61**	**44.26**	**45.49**	**50.66**	**47.89**	**51.18**	**58.23**	**51.43**

[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.

NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.

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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H9. Oil and Gas Supply

Production and Supply	1999	Projections 2005 Reference	2005 NO_x, SO_2, CO_2 1990, Hg	2005 All CO_2 1990	2010 Reference	2010 NO_x, SO_2, CO_2 1990, Hg	2010 All CO_2 1990	2020 Reference	2020 NO_x, SO_2, CO_2 1990, Hg	2020 All CO_2 1990
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	16.49	21.43	21.02	20.57	20.73	20.75	20.82	21.47	21.46	21.52
Production (million barrels per day)[2]										
U.S. Total	5.88	5.66	5.68	5.68	5.32	5.29	5.31	5.25	5.36	5.23
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.51	2.51	2.75	2.82	2.73
Conventional	2.59	2.18	2.18	2.18	1.81	1.83	1.81	1.98	2.05	1.98
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.69	0.70	0.76	0.76	0.75
Lower 48 Offshore	1.56	2.06	2.08	2.08	2.16	2.13	2.15	1.87	1.90	1.86
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	15.75	15.76	15.75	14.55	14.51	14.47	14.11	14.33	14.07
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	2.08	2.96	2.79	2.79	2.87	3.40	2.97	3.22	3.72	3.09
Production (trillion cubic feet)[3]										
U.S. Total	18.67	21.40	20.86	20.58	23.43	24.78	24.07	29.47	30.49	27.99
Lower 48 Onshore	12.83	14.46	13.97	13.82	16.71	17.56	16.71	21.31	22.44	20.26
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.33	1.32	1.39	1.43	1.40
Non-Associated	11.03	12.95	12.46	12.30	15.39	16.23	15.39	19.91	21.01	18.87
Conventional	6.64	7.67	7.42	7.33	7.93	8.42	7.99	11.14	11.44	10.89
Unconventional	4.39	5.27	5.03	4.97	7.45	7.81	7.40	8.78	9.57	7.98
Lower 48 Offshore	5.43	6.47	6.42	6.29	6.22	6.72	6.86	7.59	7.49	7.16
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.04	1.03
Non-Associated	4.50	5.41	5.35	5.23	5.13	5.64	5.77	6.56	6.44	6.13
Alaska	0.42	0.47	0.46	0.47	0.50	0.50	0.50	0.57	0.56	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	157.41	167.88	170.13	169.85	185.55	185.42	180.70	200.71	204.89	191.13
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	28.87	27.91	27.86	29.86	33.73	29.96	39.36	44.13	32.62

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
Btu = British thermal unit.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Production[1]										
Appalachia	433	426	424	423	421	267	293	396	236	275
Interior	185	182	185	180	180	130	135	161	123	126
West	486	624	552	573	694	392	422	783	328	418
East of the Mississippi	559	561	564	559	557	392	423	524	352	394
West of the Mississippi	544	672	597	618	738	398	428	817	335	425
Total	**1103**	**1233**	**1161**	**1177**	**1295**	**790**	**850**	**1340**	**687**	**819**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	59	60	56	62	63
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-50**	**-51**	**-36**	**-53**	**-54**
Total Supply[2]	**1054**	**1189**	**1113**	**1129**	**1254**	**739**	**799**	**1304**	**635**	**765**
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	86	85	86
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1003	1016	1145	629	690	1196	527	655
Total	**1032**	**1189**	**1115**	**1128**	**1256**	**737**	**799**	**1306**	**636**	**765**
Discrepancy and Stock Change[5]	**21**	**-1**	**-2**	**0**	**-2**	**2**	**-0**	**-2**	**-2**	**-0**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	15.33	15.09	14.08	15.09	15.57	12.87	13.66	14.22
(1999 dollars per million Btu)	0.82	0.73	0.73	0.72	0.69	0.70	0.72	0.64	0.63	0.66
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.65	29.59	28.61	26.25	26.77	26.50	23.84	24.54
Coke Plants	44.28	42.39	42.54	42.51	41.36	41.62	41.68	38.52	38.64	38.98
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	21.83	21.91	21.28	20.45	21.26	19.41	18.14	19.62
(1999 dollars per million Btu)	1.21	1.14	1.07	1.08	1.06	0.97	1.01	0.98	0.87	0.94
Average	**25.77**	**23.78**	**22.88**	**22.93**	**22.13**	**21.73**	**22.40**	**20.15**	**19.51**	**20.65**
Exports[7]	37.44	36.39	36.41	36.41	35.66	34.25	34.63	33.09	31.08	31.91

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
Btu = British thermal unit.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.34	79.26	79.38	80.69	79.74	79.38	80.69	79.74
Geothermal[2]	2.87	3.43	6.94	8.18	4.93	8.50	13.24	4.95	8.89	15.49
Municipal Solid Waste[3]	2.61	2.96	3.24	3.72	3.42	4.30	4.30	3.93	4.83	4.93
Wood and Other Biomass[4]	1.57	1.75	1.81	5.33	2.12	2.42	22.36	2.45	4.09	55.76
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	7.00	10.90	7.52	7.98	30.30	7.76	13.71	89.79
Total	**88.83**	**94.75**	**98.76**	**107.82**	**97.98**	**104.49**	**150.55**	**99.49**	**113.23**	**246.73**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.47	301.20	301.13	305.54	302.28	300.07	304.39	301.19
Geothermal[2]	13.21	18.34	47.37	57.39	30.94	60.34	98.37	31.16	63.66	116.13
Municipal Solid Waste[3]	18.12	20.68	22.94	26.66	23.88	30.75	30.76	27.76	34.81	35.58
Wood and Other Biomass[4]	9.02	14.94	27.64	51.78	21.30	66.36	207.22	19.78	69.61	423.00
Dedicated Plants	7.73	9.16	9.55	33.04	11.36	13.46	146.50	13.82	24.85	369.60
Cofiring	1.29	5.78	18.09	18.73	9.94	52.90	60.72	5.95	44.77	53.40
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	16.53	26.92	18.16	19.46	82.38	18.83	38.05	252.17
Total	**355.43**	**372.61**	**417.09**	**465.09**	**397.03**	**484.05**	**722.64**	**400.32**	**513.25**	**1130.79**
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	5.17	5.19	5.19	6.06	6.07	6.07	7.54	7.56	7.56
Total	**5.35**	**5.87**	**5.89**	**5.89**	**6.76**	**6.77**	**6.77**	**8.24**	**8.26**	**8.26**
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	29.92	30.01	30.03	35.01	35.00	35.00	43.52	43.54	43.55
Total	**31.12**	**33.97**	**34.05**	**34.07**	**39.05**	**39.04**	**39.05**	**47.57**	**47.58**	**47.60**
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	0.76	0.76
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.18**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.

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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**	**0.44**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	0.43	0.44
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**	**2.42**	**2.41**	**2.41**	**2.64**	**2.63**	**2.63**	**3.08**	**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	2.23	2.22	2.22	2.46	2.44	2.44	2.90	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.21**	**0.22**	**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	0.20	0.21	0.21	0.20
Electric Generators[5]	**3.88**	**4.19**	**5.23**	**5.92**	**4.73**	**6.23**	**9.45**	**4.78**	**6.62**	**13.84**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.10	3.14	3.11	3.08	3.13	3.10
Geothermal	0.28	0.44	1.33	1.64	0.85	1.74	3.08	0.85	1.86	3.74
Municipal Solid Waste[6]	0.25	0.28	0.31	0.36	0.32	0.42	0.42	0.38	0.47	0.48
Biomass	0.12	0.18	0.31	0.52	0.26	0.71	1.98	0.25	0.74	3.90
Dedicated Plants	0.10	0.11	0.11	0.33	0.14	0.14	1.40	0.17	0.26	3.41
Cofiring	0.02	0.07	0.20	0.19	0.12	0.57	0.58	0.07	0.48	0.49
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	0.28	0.19	0.20	0.85	0.19	0.39	2.59
Total Marketed Renewable Energy	**6.64**	**7.31**	**8.34**	**9.02**	**8.10**	**9.58**	**12.81**	**8.62**	**10.45**	**17.67**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**	**0.03**
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	0.18	0.18	0.20	0.19	0.20	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**	**0.22**	**0.21**	**0.22**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.5	24.6	23.2	23.6	23.4
Natural Gas	69.5	80.2	80.6	80.6	80.8	79.7	80.9	89.8	89.3	91.6
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.2	1.3
Electricity	193.4	227.1	210.7	210.7	242.6	168.1	168.1	275.6	174.1	173.9
Total	**290.1**	**335.0**	**319.1**	**319.1**	**349.2**	**273.7**	**274.9**	**389.8**	**288.2**	**290.1**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.2	12.0	12.1	12.4	12.1
Natural Gas	45.4	57.4	57.8	57.8	60.1	59.3	60.5	63.9	68.4	70.6
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	203.3	203.3	240.4	168.1	168.2	267.1	166.6	165.9
Total	**242.1**	**289.4**	**274.7**	**274.7**	**314.3**	**241.3**	**242.6**	**345.0**	**249.3**	**250.6**
Industrial[1]										
Petroleum	104.2	99.2	98.6	98.4	105.3	106.1	104.5	113.6	115.6	112.5
Natural Gas[2]	141.6	148.4	148.1	147.9	159.8	160.6	162.4	180.3	187.8	189.8
Coal	55.9	65.8	65.6	65.6	65.6	63.4	64.1	65.8	65.0	65.8
Electricity	178.8	193.6	179.7	179.6	204.1	141.6	141.0	226.4	133.8	130.6
Total	**480.4**	**507.0**	**491.9**	**491.5**	**534.8**	**471.7**	**472.0**	**586.1**	**502.3**	**498.8**
Transportation										
Petroleum[3]	485.8	556.3	554.3	554.4	607.2	603.3	603.3	704.2	700.5	700.9
Natural Gas[4]	9.5	12.8	12.5	12.4	14.4	15.0	14.9	18.1	18.7	17.4
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	4.1	4.1	5.8	4.3	4.3	7.9	5.4	5.3
Total[3]	**498.2**	**573.6**	**571.0**	**571.0**	**627.5**	**622.7**	**622.5**	**730.2**	**724.6**	**723.8**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	691.2	691.2	749.0	746.1	744.4	853.1	852.1	848.9
Natural Gas	266.0	298.8	299.0	298.7	315.1	314.6	318.7	352.0	364.1	369.5
Coal	58.8	68.8	68.5	68.6	68.8	66.6	67.2	69.0	68.2	69.0
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	643.6	597.9	597.7	692.8	482.0	481.6	777.0	479.9	475.7
Total[3]	**1510.8**	**1705.0**	**1656.7**	**1656.2**	**1825.7**	**1609.4**	**1612.0**	**2051.2**	**1764.4**	**1763.2**
Electric Generators[6]										
Petroleum	20.0	9.4	3.9	3.9	5.8	2.1	2.7	5.2	2.1	2.3
Natural Gas	45.8	79.6	71.5	65.8	100.0	143.5	108.7	164.1	197.3	124.2
Coal	490.5	554.6	522.5	527.9	587.0	336.4	370.2	607.7	280.5	349.2
Total	**556.3**	**643.6**	**597.9**	**597.7**	**692.8**	**482.0**	**481.6**	**777.0**	**479.9**	**475.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	695.1	695.1	754.8	748.3	747.0	858.3	854.2	851.2
Natural Gas	311.8	378.4	370.5	364.5	415.0	458.1	427.3	516.2	561.4	493.7
Coal	549.3	623.3	591.0	596.4	655.8	403.0	437.5	676.7	348.7	418.2
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**	**1705.0**	**1656.7**	**1656.2**	**1825.7**	**1609.4**	**1612.0**	**2051.2**	**1764.4**	**1763.2**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.8**	**5.8**	**6.1**	**5.4**	**5.4**	**6.3**	**5.4**	**5.4**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Table H14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990	Reference	NO_x, SO_2, CO_2 1990, Hg	All CO_2 1990
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.08	3.02	4.34	1.51	1.66	4.49	1.34	1.53
Sulfur Dioxide (million tons)	13.71	10.38	8.55	8.55	9.70	3.33	4.49	8.95	2.63	3.27
Mercury (tons)	43.60	45.24	39.24	40.25	45.60	5.00	5.00	45.07	5.00	5.00
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	597.91	597.66	692.78	482.04	481.60	776.99	479.90	475.70
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	1482	1640	4391	0	0	5037	0	1304
Sulfur Dioxide (1999 dollars per ton)	0	190	142	177	187	1	3	241	2	150
Mercury (million 1999 dollars per ton)	0	0	0	0	0	443	432	0	297	407
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	30	20	0	84	84	0	135	71
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	26.4	17.5	7.1	31.2	28.1	14.8	31.2	32.2
Combustion	0.0	39.9	49.9	51.0	42.1	53.5	54.8	46.1	55.6	56.9
SCR Post-combustion	0.0	92.8	61.6	69.8	92.9	109.4	131.6	93.0	109.4	134.6
SNCR Post-combustion	0.0	25.2	15.4	14.9	26.3	65.3	34.3	43.4	65.4	34.6
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	553	580	642	386	422	721	326	412
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	409	412	464	267	286	440	232	274
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	199	185	188	136	143	179	129	133

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A.

Appendix I

Tables for Integrated Cases With Four Emissions Caps, Including CO_2 Emissions at the 1990-7% Level

Table I1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.02	12.00	11.27	11.19	11.22	11.12	11.46	11.14
Natural Gas Plant Liquids	2.62	3.12	3.04	3.00	3.37	3.64	3.57	4.16	4.27	4.01
Dry Natural Gas	19.16	21.95	21.39	21.10	24.04	25.97	25.49	30.24	31.07	29.14
Coal	23.08	25.45	24.27	24.45	26.55	14.56	16.25	27.16	13.81	15.80
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	7.10
Renewable Energy[1]	6.53	7.13	8.12	8.84	7.90	9.90	12.48	8.42	10.99	17.36
Other[2]	1.65	0.35	0.58	0.58	0.31	0.30	0.31	0.33	0.33	0.32
Total	**73.29**	**77.88**	**77.33**	**77.88**	**81.19**	**73.46**	**77.23**	**87.97**	**79.20**	**84.87**
Imports										
Crude Oil[3]	18.96	21.42	21.38	21.40	22.38	22.49	22.45	25.82	25.73	25.91
Petroleum Products[4]	4.14	6.28	5.85	5.89	8.65	8.10	8.04	10.80	10.22	10.60
Natural Gas	3.63	5.13	5.13	5.00	5.55	6.97	5.88	6.59	8.47	6.63
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.89	0.88	0.96	0.81	0.81
Total	**27.37**	**33.93**	**33.38**	**33.30**	**37.54**	**38.44**	**37.24**	**44.18**	**45.24**	**43.95**
Exports										
Petroleum[6]	1.98	1.73	1.76	1.75	1.69	1.70	1.72	1.85	1.81	1.87
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.12	0.43	0.63	0.12	0.63
Coal	1.48	1.51	1.51	1.51	1.45	1.42	1.50	1.41	1.54	1.40
Total	**3.62**	**3.57**	**3.59**	**3.58**	**3.58**	**3.24**	**3.64**	**3.89**	**3.47**	**3.90**
Discrepancy[7]	**0.69**	**0.43**	**0.54**	**0.50**	**0.04**	**0.05**	**0.07**	**0.11**	**0.08**	**0.16**
Consumption										
Petroleum Products[8]	38.02	41.34	40.92	40.92	44.44	44.16	44.04	50.45	50.29	50.12
Natural Gas	22.21	26.44	25.89	25.46	29.00	32.62	30.77	36.06	39.26	34.98
Coal	21.42	24.39	23.13	23.35	25.64	13.48	15.05	26.42	12.69	14.81
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	7.10
Renewable Energy[1]	6.54	7.13	8.12	8.84	7.91	9.91	12.49	8.43	11.00	17.37
Other[9]	0.35	0.61	0.61	0.61	0.38	0.52	0.51	0.25	0.38	0.38
Total	**96.33**	**107.81**	**106.57**	**107.10**	**115.11**	**108.60**	**110.77**	**128.16**	**120.89**	**124.76**
Net Imports - Petroleum	**21.12**	**25.96**	**25.48**	**25.54**	**29.34**	**28.89**	**28.77**	**34.78**	**34.15**	**34.64**
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	2.96	2.79	2.80	2.87	3.66	3.13	3.22	3.74	3.31
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.79	14.93	14.08	14.38	15.43	12.87	13.41	14.08
Average Electric Price (cents per Kwh)	6.6	6.4	6.7	6.7	6.1	8.4	8.6	6.2	8.6	8.0

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.81	0.81	0.76	0.77	0.77
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.41	0.40
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.25	1.24
Natural Gas	4.88	5.57	5.60	5.60	5.61	5.49	5.59	6.23	6.20	6.31
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	0.44	0.43	0.43
Electricity	3.91	4.57	4.50	4.51	4.95	4.56	4.54	5.79	5.29	5.39
Delivered Energy	**10.66**	**12.01**	**11.97**	**11.98**	**12.34**	**11.83**	**11.91**	**13.74**	**13.21**	**13.42**
Electricity Related Losses	8.44	9.67	9.35	9.53	10.10	8.26	8.92	10.85	8.82	10.18
Total	**19.10**	**21.68**	**21.32**	**21.51**	**22.44**	**20.09**	**20.83**	**24.59**	**22.04**	**23.60**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.39	0.38	0.37	0.41	0.38
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	0.60	0.61	0.60	0.62	0.63	0.62	0.62	0.66	0.62
Natural Gas	3.14	3.99	4.01	4.01	4.17	4.07	4.19	4.44	4.81	4.96
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	4.39	4.34	4.35	4.91	4.58	4.55	5.62	5.04	5.12
Delivered Energy	**7.55**	**9.13**	**9.11**	**9.12**	**9.85**	**9.43**	**9.51**	**10.83**	**10.67**	**10.87**
Electricity Related Losses	7.91	9.30	9.02	9.20	10.01	8.28	8.94	10.51	8.41	9.68
Total	**15.46**	**18.44**	**18.13**	**18.32**	**19.86**	**17.71**	**18.45**	**21.34**	**19.09**	**20.55**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.21	1.21	1.31	1.29	1.29	1.49	1.48	1.47
Liquefied Petroleum Gas	2.32	2.45	2.42	2.42	2.53	2.57	2.53	2.85	2.91	2.84
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.37	0.26	0.28	0.29	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.42	4.42	4.71	4.73	4.71	5.02	5.10	5.05
Petroleum Subtotal	9.45	9.86	9.80	9.80	10.57	10.72	10.56	11.63	11.75	11.62
Natural Gas[6]	9.80	10.46	10.44	10.42	11.27	11.17	11.42	12.73	13.28	13.35
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	1.81	1.80	1.81	1.83	1.76	1.77	1.87	1.87	1.88
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.59	2.52	2.53	2.60	2.59	2.60
Renewable Energy[7]	2.15	2.42	2.41	2.41	2.64	2.63	2.63	3.08	3.08	3.08
Electricity	3.61	3.90	3.83	3.84	4.17	3.88	3.86	4.76	4.03	4.04
Delivered Energy	**27.56**	**29.23**	**29.06**	**29.06**	**31.24**	**30.92**	**31.01**	**34.80**	**34.73**	**34.68**
Electricity Related Losses	7.80	8.25	7.97	8.12	8.50	7.02	7.59	8.91	6.73	7.64
Total	**35.36**	**37.48**	**37.03**	**37.18**	**39.74**	**37.95**	**38.59**	**43.71**	**41.46**	**42.32**

Table I2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Transportation										
Distillate Fuel	5.13	6.28	6.23	6.24	7.00	6.86	6.87	8.22	8.10	8.11
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.49	5.97	5.96	5.97
Motor Gasoline[2]	15.92	17.67	17.64	17.64	18.97	18.88	18.89	21.26	21.19	21.19
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	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	0.30	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.93	28.93	31.68	31.42	31.45	36.73	36.52	36.53
Pipeline Fuel Natural Gas	0.66	0.83	0.81	0.80	0.91	0.98	0.97	1.10	1.14	1.07
Compressed Natural Gas	0.02	0.06	0.05	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	0.01	0.00	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**	**30.03**	**29.91**	**29.91**	**32.83**	**32.65**	**32.66**	**38.20**	**38.03**	**37.97**
Electricity Related Losses	0.13	0.19	0.18	0.19	0.24	0.21	0.23	0.31	0.28	0.31
Total	**26.41**	**30.22**	**30.09**	**30.09**	**33.07**	**32.86**	**32.89**	**38.51**	**38.30**	**38.29**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.69	8.69	9.49	9.35	9.34	10.85	10.76	10.72
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.49	5.97	5.96	5.97
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.13	3.09	3.41	3.48	3.40
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.15	19.16	21.57	21.50	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.31	1.20	1.24	1.24	1.23
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	5.01	5.00	5.35	5.43	5.38
Petroleum Subtotal	37.01	40.90	40.73	40.74	44.16	44.08	43.93	50.21	50.19	50.02
Natural Gas[6]	18.50	20.91	20.92	20.89	22.05	21.80	22.26	24.66	25.57	25.85
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.92	1.95	1.89	1.90	2.00	2.00	2.01
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	2.65	2.71	2.70	2.70	2.71	2.64	2.65	2.72	2.71	2.72
Renewable Energy[13]	2.65	2.94	2.93	2.93	3.18	3.17	3.17	3.65	3.63	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	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	12.95	12.76	12.79	14.15	13.14	13.07	16.34	14.53	14.72
Delivered Energy	**72.05**	**80.41**	**80.04**	**80.06**	**86.27**	**84.83**	**85.08**	**97.57**	**96.64**	**96.95**
Electricity Related Losses	24.29	27.40	26.53	27.04	28.84	23.77	25.68	30.58	24.25	27.81
Total	**96.33**	**107.81**	**106.57**	**107.10**	**115.11**	**108.60**	**110.77**	**128.16**	**120.89**	**124.76**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.03	0.03	0.06	0.01	0.02	0.06	0.02	0.02
Residual Fuel	0.96	0.38	0.15	0.15	0.22	0.07	0.09	0.19	0.08	0.09
Petroleum Subtotal	1.02	0.44	0.18	0.18	0.28	0.09	0.12	0.25	0.10	0.10
Natural Gas	3.71	5.53	4.97	4.57	6.94	10.83	8.51	11.40	13.69	9.14
Steam Coal	18.77	21.68	20.43	20.65	22.93	10.83	12.40	23.70	9.97	12.09
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	7.10
Renewable Energy[15]	3.88	4.19	5.19	5.91	4.73	6.74	9.32	4.78	7.37	13.73
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.51	0.50	0.24	0.37	0.37
Total	**35.52**	**40.35**	**39.29**	**39.82**	**42.99**	**36.91**	**38.75**	**46.92**	**38.77**	**42.53**

Table I2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.72	8.72	9.54	9.36	9.36	10.91	10.78	10.74
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.49	5.97	5.96	5.97
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.13	3.09	3.41	3.48	3.40
Motor Gasoline[2]	16.17	17.93	17.89	17.89	19.24	19.15	19.16	21.57	21.50	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	2.01	1.48	1.26	1.26	1.42	1.38	1.30	1.42	1.33	1.32
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	5.01	5.00	5.35	5.43	5.38
Petroleum Subtotal	38.02	41.34	40.92	40.92	44.44	44.16	44.04	50.45	50.29	50.12
Natural Gas	22.21	26.44	25.89	25.46	29.00	32.62	30.77	36.06	39.26	34.98
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	22.35	22.57	24.88	12.72	14.30	25.70	11.97	14.10
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.22
Coal Subtotal	21.42	24.39	23.13	23.35	25.64	13.48	15.05	26.42	12.69	14.81
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.91	7.91	6.54	7.27	7.10
Renewable Energy[17]	6.54	7.13	8.12	8.84	7.91	9.91	12.49	8.43	11.00	17.37
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	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	0.51	0.50	0.24	0.37	0.37
Total	**96.33**	**107.81**	**106.57**	**107.10**	**115.11**	**108.60**	**110.77**	**128.16**	**120.89**	**124.76**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.04	80.06	86.27	84.83	85.08	97.57	96.64	96.95
Total Energy Use	96.33	107.81	106.57	107.10	115.11	108.60	110.77	128.16	120.89	124.76
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	10960	10904	10909	12667	12611	12617	16515	16523	16521
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1657.0	1656.4	1825.7	1560.4	1570.8	2051.2	1740.4	1729.8

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Residential	**13.10**	**13.27**	**13.56**	**13.50**	**13.46**	**16.28**	**16.12**	**13.77**	**16.35**	**15.56**
Primary Energy[1]	6.71	7.49	7.37	7.37	7.18	7.76	7.38	7.08	7.48	7.16
Petroleum Products[2]	7.55	9.20	9.14	9.15	9.37	9.41	9.34	9.47	9.46	9.55
Distillate Fuel	6.27	7.45	7.37	7.37	7.57	7.56	7.56	7.78	7.74	7.74
Liquefied Petroleum Gas	10.36	12.60	12.57	12.59	12.86	13.02	12.80	12.75	12.74	13.08
Natural Gas	6.52	7.11	6.97	6.97	6.72	7.42	6.97	6.65	7.12	6.73
Electricity	23.47	22.16	23.27	23.09	22.30	29.07	29.48	22.44	28.93	27.42
Commercial	**13.18**	**12.70**	**13.19**	**13.09**	**12.25**	**16.06**	**16.01**	**12.69**	**15.92**	**14.75**
Primary Energy[1]	5.22	5.57	5.44	5.44	5.68	6.27	5.89	5.79	6.17	5.84
Petroleum Products[2]	4.99	6.13	6.07	6.08	6.29	6.26	6.26	6.40	6.30	6.41
Distillate Fuel	4.37	5.24	5.16	5.17	5.36	5.32	5.33	5.53	5.47	5.49
Residual Fuel	2.63	3.65	3.61	3.61	3.71	3.69	3.69	3.86	3.84	3.84
Natural Gas[3]	5.34	5.55	5.41	5.41	5.66	6.36	5.91	5.78	6.23	5.84
Electricity	21.45	20.26	21.56	21.32	18.76	26.27	26.84	19.00	26.64	24.59
Industrial[4]	**5.27**	**5.76**	**5.80**	**5.78**	**5.67**	**6.74**	**6.57**	**5.90**	**6.72**	**6.36**
Primary Energy	3.91	4.47	4.37	4.38	4.49	4.83	4.56	4.68	4.88	4.71
Petroleum Products[2]	5.54	6.00	5.94	5.94	6.13	6.12	6.05	6.16	6.15	6.24
Distillate Fuel	4.65	5.40	5.33	5.33	5.56	5.49	5.50	5.73	5.69	5.69
Liquefied Petroleum Gas	8.50	7.74	7.70	7.71	7.88	8.07	7.81	7.76	7.84	8.11
Residual Fuel	2.78	3.38	3.35	3.35	3.44	3.33	3.42	3.59	3.58	3.58
Natural Gas[5]	2.79	3.64	3.50	3.50	3.50	4.25	3.75	3.85	4.34	3.90
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.53	1.55	1.44	1.44	1.44
Steam Coal	1.43	1.35	1.34	1.35	1.31	1.18	1.21	1.21	1.08	1.11
Electricity	13.00	12.80	13.71	13.55	12.08	17.88	18.39	12.22	18.36	16.79
Transportation	**8.30**	**9.39**	**9.35**	**9.35**	**9.69**	**9.74**	**9.75**	**9.20**	**9.21**	**9.24**
Primary Energy	8.29	9.38	9.33	9.33	9.68	9.71	9.72	9.18	9.18	9.21
Petroleum Products[2]	8.28	9.37	9.33	9.33	9.67	9.71	9.72	9.18	9.17	9.21
Distillate Fuel[6]	8.22	8.98	8.89	8.90	8.95	8.93	8.94	8.83	8.81	8.83
Jet Fuel[7]	4.70	5.29	5.23	5.23	5.49	5.48	5.48	5.72	5.71	5.72
Motor Gasoline[8]	9.45	10.81	10.77	10.77	11.31	11.37	11.39	10.60	10.59	10.65
Residual Fuel	2.46	3.11	3.10	3.10	3.18	3.18	3.17	3.33	3.32	3.32
Liquid Petroleum Gas[9]	12.87	14.07	14.02	14.04	14.07	14.27	14.00	13.70	13.76	13.96
Natural Gas[10]	7.02	7.28	7.13	7.13	7.21	7.92	7.47	7.41	7.86	7.45
Ethanol (E85)[11]	14.42	19.21	19.19	19.18	19.16	19.28	19.28	19.36	19.43	19.39
Methanol (M85)[12]	10.38	13.13	12.98	12.99	13.83	14.14	13.84	14.35	14.35	14.37
Electricity	15.59	14.52	15.01	15.02	13.62	17.06	17.92	13.22	16.67	16.11
Average End-Use Energy	**8.49**	**9.17**	**9.27**	**9.24**	**9.22**	**10.42**	**10.35**	**9.21**	**10.20**	**9.87**
Primary Energy	6.31	7.19	7.11	7.11	7.35	7.58	7.42	7.23	7.33	7.23
Electricity	19.41	18.65	19.76	19.57	17.99	24.68	25.18	18.19	25.06	23.39
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.55	1.51	1.59	2.68	2.14	1.88	2.96	2.21
Petroleum Products	2.49	3.61	3.82	3.81	3.90	4.35	4.15	4.17	4.48	4.49
Distillate Fuel	4.04	4.72	4.72	4.75	4.87	4.92	4.88	5.06	5.12	5.18
Residual Fuel	2.40	3.42	3.64	3.63	3.65	4.25	3.98	3.89	4.35	4.37
Natural Gas	2.58	3.44	3.40	3.37	3.26	4.41	3.79	3.71	4.49	3.93
Steam Coal	1.21	1.14	1.08	1.08	1.06	0.93	0.98	0.98	0.85	0.90

Table I3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.51	8.51	8.81	8.84	8.84	8.49	8.49	8.55
Distillate Fuel	7.25	8.14	8.07	8.08	8.20	8.18	8.20	8.20	8.17	8.20
Jet Fuel	4.70	5.29	5.23	5.23	5.49	5.48	5.48	5.72	5.71	5.72
Liquefied Petroleum Gas	8.84	8.63	8.60	8.62	8.74	8.92	8.68	8.54	8.60	8.89
Motor Gasoline[8]	9.45	10.80	10.77	10.76	11.31	11.37	11.39	10.60	10.59	10.65
Residual Fuel	2.47	3.25	3.23	3.23	3.33	3.31	3.32	3.49	3.48	3.48
Natural Gas	4.05	4.72	4.63	4.65	4.47	5.19	4.74	4.60	5.14	4.78
Coal	1.23	1.16	1.10	1.10	1.08	0.97	1.02	1.00	0.89	0.93
Ethanol (E85)[11]	14.42	19.21	19.19	19.18	19.16	19.28	19.28	19.36	19.43	19.39
Methanol (M85)[12]	10.38	13.13	12.98	12.99	13.83	14.14	13.84	14.35	14.35	14.37
Electricity	19.41	18.65	19.76	19.57	17.99	24.68	25.18	18.19	25.06	23.39
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	156.58	155.98	160.41	185.71	185.06	183.27	208.97	202.13
Commercial	98.42	114.97	119.06	118.24	119.69	150.12	150.84	136.41	168.56	159.06
Industrial	111.66	127.05	127.60	127.20	133.28	157.93	154.78	154.57	177.19	167.45
Transportation	212.64	273.84	271.54	271.60	308.81	307.79	308.43	340.45	338.89	340.30
Total Non-Renewable Expenditures	556.99	669.69	674.79	673.02	722.19	801.56	799.11	814.69	893.61	868.95
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.63	0.85	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**675.21**	**673.43**	**722.82**	**802.19**	**799.75**	**815.54**	**894.46**	**869.79**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	1995	2013	2245	1069	1223	2315	988	1190
Petroleum	94	43	19	19	28	9	13	25	11	11
Natural Gas[2]	359	583	619	563	825	1575	1189	1495	2005	1304
Nuclear Power	730	740	740	740	725	741	741	613	681	665
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	416	465	397	503	706	400	554	1128
Total	**3369**	**3844**	**3789**	**3799**	**4219**	**3895**	**3871**	**4847**	**4238**	**4298**
Non-Utility Generation for Own Use	16	17	21	21	17	20	20	17	20	19
Distributed Generation	0	0	0	0	1	1	0	5	1	1
Cogenerators[4]										
Coal	47	53	52	53	52	44	45	52	44	45
Petroleum	9	10	10	10	10	10	10	10	11	10
Natural Gas	207	237	243	240	261	314	323	318	602	605
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	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**	**345**	**350**	**348**	**373**	**419**	**429**	**441**	**718**	**722**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	151	172	171	171	180	178	183	208	271	272
Generation for Own Use	156	178	184	182	198	246	251	238	452	455
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**49**	**47**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1145	1339	1318	1321	1452	1338	1331	1698	1549	1579
Commercial	1073	1288	1272	1275	1439	1341	1334	1646	1477	1501
Industrial	1058	1142	1123	1126	1222	1138	1132	1395	1182	1184
Transportation	17	26	26	26	35	34	34	49	48	48
Total	**3294**	**3794**	**3738**	**3747**	**4147**	**3851**	**3830**	**4788**	**4257**	**4313**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.9	7.9	7.6	9.9	10.1	7.7	9.9	9.4
Commercial	7.3	6.9	7.4	7.3	6.4	9.0	9.2	6.5	9.1	8.4
Industrial	4.4	4.4	4.7	4.6	4.1	6.1	6.3	4.2	6.3	5.7
Transportation	5.3	5.0	5.1	5.1	4.6	5.8	6.1	4.5	5.7	5.5
All Sectors Average	**6.6**	**6.4**	**6.7**	**6.7**	**6.1**	**8.4**	**8.6**	**6.2**	**8.6**	**8.0**
Prices by Service Category[9] (1999 cents per kwh)										
Generation	4.1	3.8	4.2	4.1	3.5	5.6	5.8	3.6	5.9	5.3
Transmission	0.6	0.6	0.6	0.6	0.7	0.8	0.8	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.71	10.38	8.55	8.55	9.70	3.19	3.60	8.95	2.92	3.17
Nitrogen Oxide	5.45	4.30	3.05	3.02	4.34	1.26	1.41	4.49	1.25	1.37

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	302.8	302.8	318.6	269.9	273.7	318.5	238.3	240.3
Other Fossil Steam[3]	137.4	127.8	119.9	118.8	119.2	104.7	102.8	116.9	94.3	93.0
Combined Cycle	21.0	53.2	84.1	78.7	107.8	226.2	161.5	202.2	277.7	183.9
Combustion Turbine/Diesel	74.3	123.1	114.3	114.8	147.2	116.0	117.7	199.5	125.4	139.9
Nuclear Power	97.4	97.5	97.5	97.5	94.8	96.9	96.9	76.3	87.6	84.6
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	94.8	98.7	107.8	98.0	109.0	151.9	99.5	121.5	247.5
Distributed Generation[5]	0.0	0.7	0.6	0.5	2.5	1.2	0.9	11.5	3.2	3.4
Total	**743.4**	**820.4**	**837.4**	**840.4**	**907.8**	**943.5**	**925.0**	**1044.2**	**967.8**	**1012.2**
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	0.0	0.0	18.9	0.0	0.0	20.5	0.0	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	19.4	50.3	45.0	74.2	192.6	127.9	168.6	244.0	152.2
Combustion Turbine/Diesel	0.0	38.9	31.5	31.4	64.7	34.2	36.3	117.2	43.9	58.7
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	4.4	13.5	2.0	13.0	55.9	2.0	24.0	150.1
Distributed Generation[5]	0.0	0.7	0.6	0.5	2.5	1.2	0.9	11.5	3.2	3.4
Total	**0.0**	**60.6**	**86.8**	**90.4**	**162.2**	**241.0**	**221.0**	**319.8**	**315.1**	**364.4**
Cumulative Total Additions	**0.0**	**92.6**	**118.8**	**122.4**	**195.9**	**274.6**	**254.7**	**355.1**	**350.4**	**399.7**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	35.3	31.4	7.2	66.8	64.9
Other Fossil Steam[3]	0.0	9.9	17.7	18.8	18.4	32.9	34.8	20.7	43.2	44.5
Combined Cycle	0.0	0.0	0.0	0.0	0.2	0.1	0.2	0.2	0.1	2.1
Combustion Turbine/Diesel	0.0	4.4	5.7	5.1	6.0	6.7	7.1	6.3	7.0	7.4
Nuclear Power	0.0	0.0	0.0	0.0	2.6	0.6	0.6	21.2	9.8	12.9
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**	**16.7**	**25.9**	**26.5**	**32.8**	**75.7**	**74.3**	**55.6**	**127.1**	**131.9**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.3	7.5	8.6	7.3	7.5
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0
Natural Gas	34.6	39.9	40.8	40.5	43.3	51.2	52.0	51.4	91.2	91.4
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	8.2	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**	**59.2**	**60.2**	**59.9**	**63.3**	**69.9**	**70.9**	**73.2**	**111.7**	**112.1**
Cumulative Additions[6]	**0.0**	**6.8**	**7.8**	**7.5**	**10.9**	**17.5**	**18.4**	**20.7**	**59.3**	**59.7**

Table I5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Other End-Use Generators[9]										
Renewable Sources	1.0	1.1	1.1	1.1	1.3	1.3	1.3	1.3	1.4	1.3
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.4	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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
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	152.0	202.3	157.8	169.2	155.5	83.4	82.9	147.9	101.2	102.9
Gross Domestic Trade	**334.2**	**327.6**	**283.1**	**294.5**	**258.4**	**186.3**	**185.8**	**147.9**	**101.2**	**102.9**
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)	4413.9	6468.6	5663.4	6025.7	4510.4	4106.8	4376.3	4605.1	5412.0	5158.1
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11569.2**	**11931.5**	**9361.6**	**8958.1**	**9227.6**	**4605.1**	**5412.0**	**5158.1**
International Electricity Trade										
Firm Power Imports From Canada and	27.0	10.7	10.7	10.7	5.8	19.1	17.9	0.0	12.1	12.1
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**	**65.0**	**63.8**	**30.6**	**42.7**	**42.7**
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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections 2005 Reference	2005 NO_x, SO_2, CO_2 1990-7%, Hg	2005 All CO_2 1990-7%	2010 Reference	2010 NO_x, SO_2, CO_2 1990-7%, Hg	2010 All CO_2 1990-7%	2020 Reference	2020 NO_x, SO_2, CO_2 1990-7%, Hg	2020 All CO_2 1990-7%
Production										
Dry Gas Production[1]	18.67	21.40	20.85	20.57	23.43	25.31	24.84	29.47	30.29	28.40
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**	**4.69**	**4.69**	**4.57**	**5.00**	**6.69**	**5.33**	**5.82**	**8.16**	**5.85**
Canada	3.29	4.48	4.48	4.36	4.72	5.06	5.03	5.43	5.74	5.46
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	0.32	-0.25	-0.40	0.36	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	1.31	0.55	0.79	2.07	0.80
Total Supply	**22.15**	**26.20**	**25.66**	**25.25**	**28.49**	**32.06**	**30.23**	**35.35**	**38.51**	**34.31**
Consumption by Sector										
Residential	4.75	5.42	5.45	5.45	5.46	5.34	5.44	6.07	6.03	6.15
Commercial	3.06	3.88	3.91	3.91	4.06	3.96	4.08	4.32	4.69	4.83
Industrial[3]	8.31	8.81	8.82	8.82	9.48	9.28	9.56	10.53	11.03	11.18
Electric Generators[4]	3.64	5.43	4.87	4.49	6.81	10.63	8.35	11.19	13.43	8.97
Lease and Plant Fuel[5]	1.23	1.38	1.35	1.34	1.50	1.59	1.57	1.87	1.90	1.81
Pipeline Fuel	0.64	0.81	0.79	0.78	0.88	0.95	0.94	1.07	1.11	1.05
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.65**	**25.79**	**25.25**	**24.83**	**28.29**	**31.85**	**30.03**	**35.20**	**38.33**	**34.14**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.42**	**0.20**	**0.21**	**0.20**	**0.14**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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, M2P7B08.D060801A, M2P7B08R_X.D070601A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I8. 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	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.79	2.80	2.87	3.66	3.13	3.22	3.74	3.31
Average Import Price	2.29	2.95	2.92	2.90	2.64	3.05	2.83	2.72	3.10	2.84
Average[2]	**2.11**	**2.96**	**2.82**	**2.82**	**2.82**	**3.53**	**3.07**	**3.13**	**3.60**	**3.22**
Delivered Prices										
Residential	6.69	7.31	7.16	7.16	6.91	7.62	7.16	6.83	7.32	6.92
Commercial	5.49	5.70	5.56	5.56	5.82	6.53	6.07	5.93	6.40	5.99
Industrial[3]	2.87	3.74	3.59	3.59	3.59	4.36	3.86	3.95	4.46	4.01
Electric Generators[4]	2.63	3.50	3.46	3.44	3.32	4.49	3.86	3.78	4.57	4.00
Transportation[5]	7.21	7.48	7.33	7.32	7.40	8.13	7.67	7.61	8.07	7.65
Average[6]	**4.15**	**4.84**	**4.75**	**4.77**	**4.59**	**5.32**	**4.86**	**4.72**	**5.27**	**4.91**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.34	4.35	4.08	4.09	4.09	3.70	3.71	3.69
Commercial	3.37	2.74	2.74	2.74	2.99	3.00	3.00	2.81	2.80	2.77
Industrial[3]	0.76	0.78	0.78	0.77	0.77	0.83	0.79	0.82	0.85	0.78
Electric Generators[4]	0.52	0.54	0.65	0.62	0.49	0.96	0.79	0.65	0.97	0.78
Transportation[5]	5.10	4.51	4.51	4.51	4.58	4.60	4.60	4.48	4.47	4.43
Average[6]	**2.04**	**1.88**	**1.94**	**1.95**	**1.76**	**1.79**	**1.79**	**1.59**	**1.67**	**1.68**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.69	23.69	22.30	21.88	22.28	22.48	22.41	22.69
Commercial	10.32	10.63	10.72	10.72	12.16	11.89	12.24	12.12	13.12	13.39
Industrial[3]	6.28	6.86	6.83	6.83	7.26	7.74	7.51	8.65	9.43	8.76
Electric Generators[4]	1.88	2.94	3.16	2.79	3.36	10.23	6.63	7.24	13.08	6.96
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.40	0.41	0.68	0.65	0.66
Total	**40.32**	**44.25**	**44.64**	**44.26**	**45.49**	**52.13**	**49.07**	**51.18**	**58.69**	**52.46**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**21.43**	**20.60**	**21.43**	**20.73**	**20.81**	**20.81**	**21.47**	**21.43**	**21.49**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.66**	**5.68**	**5.67**	**5.32**	**5.28**	**5.30**	**5.25**	**5.41**	**5.26**
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.51	2.52	2.75	2.85	2.76
Conventional	2.59	2.18	2.18	2.17	1.81	1.83	1.81	1.98	2.08	2.01
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.68	0.70	0.76	0.76	0.74
Lower 48 Offshore	1.56	2.06	2.08	2.07	2.16	2.13	2.13	1.87	1.92	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**	**15.75**	**15.75**	**15.77**	**14.55**	**14.51**	**14.49**	**14.11**	**14.44**	**14.09**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.79**	**2.80**	**2.87**	**3.66**	**3.13**	**3.22**	**3.74**	**3.31**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.40**	**20.85**	**20.57**	**23.43**	**25.31**	**24.84**	**29.47**	**30.29**	**28.40**
Lower 48 Onshore	12.83	14.46	13.96	13.81	16.71	17.95	17.32	21.31	22.03	20.50
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.32	1.33	1.32	1.39	1.45	1.41
Non-Associated	11.03	12.95	12.44	12.30	15.39	16.62	16.00	19.91	20.57	19.09
Conventional	6.64	7.67	7.42	7.33	7.93	8.73	8.34	11.14	10.90	10.85
Unconventional	4.39	5.27	5.02	4.97	7.45	7.89	7.66	8.78	9.68	8.24
Lower 48 Offshore	5.43	6.47	6.43	6.29	6.22	6.86	7.02	7.59	7.70	7.34
Associated-Dissolved[4]	0.93	1.06	1.06	1.06	1.09	1.09	1.09	1.04	1.05	1.04
Non-Associated	4.50	5.41	5.37	5.23	5.13	5.78	5.93	6.56	6.65	6.30
Alaska	0.42	0.47	0.47	0.47	0.50	0.50	0.50	0.57	0.56	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**167.88**	**169.84**	**170.11**	**185.55**	**184.56**	**179.92**	**200.71**	**212.61**	**190.22**
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**	**28.87**	**27.90**	**27.86**	**29.86**	**34.41**	**30.83**	**39.36**	**46.32**	**34.25**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Production[1]										
Appalachia	433	426	412	420	421	245	276	396	233	263
Interior	185	182	173	176	180	112	124	161	103	124
West	486	624	586	579	694	317	348	783	305	344
East of the Mississippi	559	561	540	552	557	351	394	524	329	381
West of the Mississippi	544	672	630	624	738	323	354	817	312	350
Total	**1103**	**1233**	**1170**	**1176**	**1295**	**674**	**749**	**1340**	**640**	**731**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	57	59	56	62	56
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-48**	**-50**	**-36**	**-53**	**-47**
Total Supply[2]	**1054**	**1189**	**1122**	**1128**	**1254**	**627**	**698**	**1304**	**587**	**684**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	81	81	86	86	86
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1011	1018	1145	518	587	1196	478	574
Total	**1032**	**1189**	**1123**	**1130**	**1256**	**627**	**696**	**1306**	**588**	**684**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-3**	**-2**	**-0**	**2**	**-2**	**-1**	**-0**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	14.79	14.93	14.08	14.38	15.43	12.87	13.41	14.08
(1999 dollars per million Btu)	0.82	0.73	0.71	0.72	0.69	0.67	0.71	0.64	0.62	0.65
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.44	29.49	28.61	25.71	26.39	26.50	23.55	24.18
Coke Plants	44.28	42.39	42.55	42.56	41.36	41.04	41.66	38.52	38.48	38.69
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	21.73	21.84	21.28	19.41	20.80	19.41	17.65	19.02
(1999 dollars per million Btu)	1.21	1.14	1.08	1.08	1.06	0.93	0.98	0.98	0.85	0.90
Average	**25.77**	**23.78**	**22.77**	**22.86**	**22.13**	**21.02**	**22.14**	**20.15**	**19.19**	**20.22**
Exports[7]	37.44	36.39	36.40	36.39	35.66	33.25	34.32	33.09	30.92	32.01

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.34	79.34	79.38	80.85	80.69	79.38	80.85	80.69
Geothermal[2]	2.87	3.43	6.79	8.16	4.93	10.39	13.33	4.95	10.86	15.24
Municipal Solid Waste[3]	2.61	2.96	3.24	3.69	3.42	4.42	4.41	3.93	4.94	4.95
Wood and Other Biomass[4]	1.57	1.75	1.87	5.33	2.12	3.66	19.23	2.45	5.87	56.88
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	7.05	10.90	7.52	9.04	33.66	7.76	17.92	88.76
Total	**88.83**	**94.75**	**98.72**	**107.85**	**97.98**	**108.97**	**151.93**	**99.49**	**121.45**	**247.52**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	301.47	301.47	301.13	306.09	305.53	300.07	304.94	304.42
Geothermal[2]	13.21	18.34	46.08	57.18	30.94	76.02	98.78	31.16	79.93	113.80
Municipal Solid Waste[3]	18.12	20.68	22.94	26.44	23.88	31.67	31.66	27.76	35.61	35.70
Wood and Other Biomass[4]	9.02	14.94	28.15	51.80	21.30	65.04	175.74	19.78	79.41	423.19
Dedicated Plants	7.73	9.16	9.96	33.04	11.36	21.75	125.61	13.82	36.70	377.09
Cofiring	1.29	5.78	18.19	18.76	9.94	43.30	50.13	5.95	42.71	46.10
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	16.66	26.95	18.16	22.40	92.59	18.83	51.37	248.42
Total	**355.43**	**372.61**	**416.45**	**465.01**	**397.03**	**502.84**	**705.91**	**400.32**	**553.99**	**1128.26**
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	5.17	5.19	5.19	6.06	6.06	6.07	7.54	7.55	7.56
Total	**5.35**	**5.87**	**5.89**	**5.89**	**6.76**	**6.76**	**6.77**	**8.24**	**8.25**	**8.26**
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	29.92	30.02	30.04	35.01	34.93	34.97	43.52	43.48	43.52
Total	**31.12**	**33.97**	**34.06**	**34.08**	**39.05**	**38.98**	**39.02**	**47.57**	**47.53**	**47.57**
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	0.36	0.35
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.35**	**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	0.78	0.76
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.19**	**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.

NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.

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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	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**	**2.42**	**2.41**	**2.41**	**2.64**	**2.63**	**2.63**	**3.08**	**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	2.23	2.22	2.22	2.46	2.44	2.44	2.90	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**0.21**	**0.22**	**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	0.20	0.21	0.21	0.20
Electric Generators[5]	**3.88**	**4.19**	**5.19**	**5.91**	**4.73**	**6.74**	**9.32**	**4.78**	**7.37**	**13.73**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.10	3.15	3.14	3.08	3.14	3.13
Geothermal	0.28	0.44	1.28	1.63	0.85	2.23	3.10	0.85	2.37	3.65
Municipal Solid Waste[6]	0.25	0.28	0.31	0.36	0.32	0.43	0.43	0.38	0.48	0.49
Biomass	0.12	0.18	0.31	0.52	0.26	0.68	1.68	0.25	0.82	3.89
Dedicated Plants	0.10	0.11	0.11	0.33	0.14	0.23	1.20	0.17	0.38	3.47
Cofiring	0.02	0.07	0.20	0.19	0.12	0.46	0.48	0.07	0.44	0.42
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	0.28	0.19	0.23	0.95	0.19	0.53	2.54
Total Marketed Renewable Energy	**6.64**	**7.31**	**8.30**	**9.02**	**8.10**	**10.09**	**12.68**	**8.62**	**11.20**	**17.56**
Non-Marketed Renewable Energy[7]										
Selected Consumption										
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**	**0.03**
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	0.18	0.18	0.20	0.19	0.20	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**	**0.22**	**0.21**	**0.22**	**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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.6	24.6	23.2	23.7	23.4
Natural Gas	69.5	80.2	80.6	80.6	80.8	79.0	80.5	89.8	89.2	90.9
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.2	1.3
Electricity	193.4	227.1	210.9	210.7	242.6	150.7	153.1	275.6	165.0	161.7
Total	**290.1**	**335.0**	**319.3**	**319.0**	**349.2**	**255.6**	**259.5**	**389.8**	**279.1**	**277.3**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.3	12.1	12.1	12.9	12.2
Natural Gas	45.4	57.4	57.8	57.8	60.1	58.6	60.3	63.9	69.3	71.5
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	203.5	203.4	240.4	151.1	153.4	267.1	157.4	153.8
Total	**242.1**	**289.4**	**274.8**	**274.7**	**314.3**	**223.8**	**227.6**	**345.0**	**241.5**	**239.4**
Industrial[1]										
Petroleum	104.2	99.2	98.6	98.5	105.3	108.7	105.3	113.6	115.7	113.4
Natural Gas[2]	141.6	148.4	148.0	147.8	159.8	158.4	162.1	180.3	188.5	189.5
Coal	55.9	65.8	65.6	65.7	65.6	63.9	64.2	65.8	65.7	65.9
Electricity	178.8	193.6	179.7	179.6	204.1	128.2	130.2	226.4	125.9	121.3
Total	**480.4**	**507.0**	**491.8**	**491.6**	**534.8**	**459.3**	**461.9**	**586.1**	**495.8**	**490.1**
Transportation										
Petroleum[3]	485.8	556.3	554.3	554.5	607.2	602.3	602.6	704.2	700.1	700.4
Natural Gas[4]	9.5	12.8	12.5	12.4	14.4	15.4	15.3	18.1	18.6	17.7
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	4.1	4.1	5.8	3.9	4.0	7.9	5.2	5.0
Total[3]	**498.2**	**573.6**	**571.0**	**571.1**	**627.5**	**621.7**	**621.9**	**730.2**	**723.9**	**723.1**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	691.2	691.4	749.0	747.9	744.6	853.1	852.4	849.4
Natural Gas	266.0	298.8	299.0	298.6	315.1	311.5	318.2	352.0	365.6	369.5
Coal	58.8	68.8	68.5	68.6	68.8	67.1	67.3	69.0	68.9	69.1
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	643.6	598.1	597.8	692.8	433.9	440.6	777.0	453.5	441.7
Total[3]	**1510.8**	**1705.0**	**1657.0**	**1656.4**	**1825.7**	**1560.4**	**1570.8**	**2051.2**	**1740.4**	**1729.8**
Electric Generators[6]										
Petroleum	20.0	9.4	3.9	3.9	5.8	1.8	2.4	5.2	2.1	2.1
Natural Gas	45.8	79.6	71.5	65.8	100.0	155.9	122.5	164.1	197.1	131.6
Coal	490.5	554.6	522.7	528.1	587.0	276.1	315.7	607.7	254.3	308.0
Total	**556.3**	**643.6**	**598.1**	**597.8**	**692.8**	**433.9**	**440.6**	**777.0**	**453.5**	**441.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	695.1	695.2	754.8	749.7	747.0	858.3	854.5	851.5
Natural Gas	311.8	378.4	370.5	364.4	415.0	467.4	440.7	516.2	562.7	501.1
Coal	549.3	623.3	591.3	596.7	655.8	343.2	383.0	676.7	323.2	377.1
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**	**1705.0**	**1657.0**	**1656.4**	**1825.7**	**1560.4**	**1570.8**	**2051.2**	**1740.4**	**1729.8**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.8**	**5.8**	**6.1**	**5.2**	**5.2**	**6.3**	**5.4**	**5.3**

[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.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Table I14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%	Reference	NO_x, SO_2, CO_2 1990-7%, Hg	All CO_2 1990-7%
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.05	3.02	4.34	1.26	1.41	4.49	1.25	1.37
Sulfur Dioxide (million tons)	13.71	10.38	8.55	8.55	9.70	3.19	3.60	8.95	2.92	3.17
Mercury (tons)	43.60	45.24	40.82	40.74	45.60	5.00	5.00	45.07	5.00	5.00
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	598.14	597.79	692.78	433.87	440.64	776.99	453.47	441.71
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	1423	1569	4391	0	0	5037	0	1118
Sulfur Dioxide (1999 dollars per ton)	0	190	192	218	187	0	2	241	1	0
Mercury (million 1999 dollars per ton)	0	0	0	0	0	296	342	0	219	337
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	28	19	0	120	124	0	150	90
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	9.7	13.3	7.1	21.2	27.5	14.8	21.2	32.5
Combustion	0.0	39.9	51.8	50.6	42.1	56.5	52.5	46.1	56.9	55.4
SCR Post-combustion	0.0	92.8	60.9	68.7	92.9	103.8	122.5	93.0	103.8	123.1
SNCR Post-combustion	0.0	25.2	21.9	15.6	26.3	72.8	53.3	43.4	72.8	53.3
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	590	588	642	304	349	721	307	345
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	402	406	464	243	261	440	216	248
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	178	181	188	128	139	179	117	138

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
NO_x = Nitrogen oxide.
SO_2 = Sulfur dioxide.
CO_2 = Carbon dioxide.
Hg = Mercury.
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 M2BASE.D060801A, M2P7B08.D060801A, M2P7B08R_X.D070601A.

Appendix J

Tables for the Integrated Moderate Targets Case

Table J1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Production							
Crude Oil and Lease Condensate	12.45	11.98	12.00	11.27	11.22	11.12	11.27
Natural Gas Plant Liquids	2.62	3.12	3.03	3.37	3.55	4.16	4.17
Dry Natural Gas	19.16	21.95	21.30	24.04	25.31	30.24	30.29
Coal	23.08	25.45	24.42	26.55	18.87	27.16	17.48
Nuclear Power	7.79	7.90	7.90	7.74	7.91	6.54	7.10
Renewable Energy[1]	6.53	7.13	7.78	7.90	9.97	8.42	12.32
Other[2]	1.65	0.35	0.58	0.31	0.31	0.33	0.33
Total	**73.29**	**77.88**	**77.02**	**81.19**	**77.14**	**87.97**	**82.95**
Imports							
Crude Oil[3]	18.96	21.42	21.39	22.38	22.45	25.82	25.82
Petroleum Products[4]	4.14	6.28	5.87	8.65	8.10	10.80	10.46
Natural Gas	3.63	5.13	5.14	5.55	5.77	6.59	6.83
Other Imports[5]	0.64	1.11	1.02	0.96	0.89	0.96	0.81
Total	**27.37**	**33.93**	**33.42**	**37.54**	**37.21**	**44.18**	**43.92**
Exports							
Petroleum[6]	1.98	1.73	1.75	1.69	1.71	1.85	1.81
Natural Gas	0.17	0.33	0.33	0.43	0.43	0.63	0.63
Coal	1.48	1.51	1.51	1.45	1.52	1.41	1.42
Total	**3.62**	**3.57**	**3.58**	**3.58**	**3.66**	**3.89**	**3.87**
Discrepancy[7]	**0.69**	**0.43**	**0.51**	**0.04**	**-0.02**	**0.11**	**0.13**
Consumption							
Petroleum Products[8]	38.02	41.34	40.92	44.44	44.09	50.45	50.25
Natural Gas	22.21	26.44	25.80	29.00	30.47	36.06	36.33
Coal	21.42	24.39	23.32	25.64	17.74	26.42	16.49
Nuclear Power	7.79	7.90	7.90	7.74	7.91	6.54	7.10
Renewable Energy[1]	6.54	7.13	7.78	7.91	9.97	8.43	12.33
Other[9]	0.35	0.61	0.61	0.38	0.52	0.25	0.38
Total	**96.33**	**107.81**	**106.35**	**115.11**	**110.70**	**128.16**	**122.88**
Net Imports - Petroleum	**21.12**	**25.96**	**25.52**	**29.34**	**28.84**	**34.78**	**34.47**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.22	20.83	20.83	21.37	21.37	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.96	2.79	2.87	3.09	3.22	3.74
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.86	14.08	14.14	12.87	12.68
Average Electric Price (cents per Kwh)	6.6	6.4	6.9	6.1	8.2	6.2	8.2

[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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Energy Consumption							
Residential							
Distillate Fuel	0.86	0.87	0.87	0.80	0.81	0.76	0.77
Kerosene	0.10	0.08	0.08	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.45	0.45	0.42	0.42	0.40	0.41
Petroleum Subtotal	1.42	1.40	1.40	1.30	1.30	1.23	1.25
Natural Gas	4.88	5.57	5.60	5.61	5.60	6.23	6.21
Coal	0.04	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	0.44	0.43
Electricity	3.91	4.57	4.47	4.95	4.61	5.79	5.37
Delivered Energy	**10.66**	**12.01**	**11.95**	**12.34**	**11.98**	**13.74**	**13.30**
Electricity Related Losses	8.44	9.67	9.29	10.10	8.89	10.85	9.51
Total	**19.10**	**21.68**	**21.24**	**22.44**	**20.87**	**24.59**	**22.81**
Commercial							
Distillate Fuel	0.36	0.37	0.37	0.38	0.38	0.37	0.38
Residual Fuel	0.10	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
Liquefied Petroleum Gas	0.08	0.09	0.09	0.09	0.09	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.60	0.60	0.60	0.62	0.62	0.62	0.63
Natural Gas	3.14	3.99	4.01	4.17	4.19	4.44	4.82
Coal	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
Electricity	3.66	4.39	4.32	4.91	4.60	5.62	5.11
Delivered Energy	**7.55**	**9.13**	**9.08**	**9.85**	**9.56**	**10.83**	**10.71**
Electricity Related Losses	7.91	9.30	8.97	10.01	8.87	10.51	9.05
Total	**15.46**	**18.44**	**18.05**	**19.86**	**18.43**	**21.34**	**19.77**
Industrial[4]							
Distillate Fuel	1.13	1.22	1.21	1.31	1.30	1.49	1.49
Liquefied Petroleum Gas	2.32	2.45	2.42	2.53	2.52	2.85	2.88
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	0.22	0.16	0.16	0.25	0.26	0.28	0.29
Motor Gasoline[2]	0.21	0.23	0.23	0.25	0.24	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.41	4.71	4.72	5.02	5.06
Petroleum Subtotal	9.45	9.86	9.79	10.57	10.56	11.63	11.69
Natural Gas[6]	9.80	10.46	10.44	11.27	11.44	12.73	13.31
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	1.73	1.81	1.80	1.83	1.75	1.87	1.85
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	2.54	2.59	2.59	2.59	2.51	2.60	2.57
Renewable Energy[7]	2.15	2.42	2.41	2.64	2.63	3.08	3.08
Electricity	3.61	3.90	3.82	4.17	3.88	4.76	4.08
Delivered Energy	**27.56**	**29.23**	**29.04**	**31.24**	**31.03**	**34.80**	**34.73**
Electricity Related Losses	7.80	8.25	7.94	8.50	7.47	8.91	7.23
Total	**35.36**	**37.48**	**36.98**	**39.74**	**38.49**	**43.71**	**41.96**

Table J2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Transportation							
Distillate Fuel	5.13	6.28	6.23	7.00	6.90	8.22	8.13
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.49	5.97	5.96
Motor Gasoline[2]	15.92	17.67	17.63	18.97	18.90	21.26	21.19
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.87	0.86
Liquefied Petroleum Gas	0.02	0.03	0.03	0.04	0.04	0.06	0.06
Other Petroleum[9]	0.26	0.30	0.29	0.31	0.31	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.91	31.68	31.49	36.73	36.56
Pipeline Fuel Natural Gas	0.66	0.83	0.81	0.91	0.95	1.10	1.11
Compressed Natural Gas	0.02	0.06	0.05	0.09	0.09	0.16	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.03	0.03	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.09	0.09	0.12	0.12	0.17	0.17
Delivered Energy	**26.28**	**30.03**	**29.89**	**32.83**	**32.69**	**38.20**	**38.04**
Electricity Related Losses	0.13	0.19	0.18	0.24	0.23	0.31	0.29
Total	**26.41**	**30.22**	**30.08**	**33.07**	**32.91**	**38.51**	**38.33**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.48	8.74	8.68	9.49	9.38	10.85	10.77
Kerosene	0.15	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.49	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.08	3.08	3.41	3.44
Motor Gasoline[2]	16.17	17.93	17.88	19.24	19.17	21.57	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	1.05	1.10	1.10	1.20	1.20	1.24	1.24
Other Petroleum[12]	4.53	4.71	4.68	4.99	5.00	5.35	5.39
Petroleum Subtotal	37.01	40.90	40.71	44.16	43.97	50.21	50.13
Natural Gas[6]	18.50	20.91	20.92	22.05	22.27	24.66	25.59
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	1.84	1.92	1.92	1.95	1.88	2.00	1.97
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	2.65	2.71	2.70	2.71	2.63	2.72	2.69
Renewable Energy[13]	2.65	2.94	2.93	3.18	3.17	3.65	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.24	12.95	12.70	14.15	13.21	16.34	14.73
Delivered Energy	**72.05**	**80.41**	**79.96**	**86.27**	**85.25**	**97.57**	**96.79**
Electricity Related Losses	24.29	27.40	26.38	28.84	25.45	30.58	26.09
Total	**96.33**	**107.81**	**106.35**	**115.11**	**110.70**	**128.16**	**122.88**
Electric Generators[14]							
Distillate Fuel	0.06	0.06	0.03	0.06	0.02	0.06	0.02
Residual Fuel	0.96	0.38	0.18	0.22	0.10	0.19	0.11
Petroleum Subtotal	1.02	0.44	0.21	0.28	0.12	0.25	0.13
Natural Gas	3.71	5.53	4.88	6.94	8.20	11.40	10.73
Steam Coal	18.77	21.68	20.62	22.93	15.11	23.70	13.80
Nuclear Power	7.79	7.90	7.90	7.74	7.91	6.54	7.10
Renewable Energy[15]	3.88	4.19	4.85	4.73	6.80	4.78	8.69
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.51	0.24	0.37
Total	**35.52**	**40.35**	**39.08**	**42.99**	**38.66**	**46.92**	**40.82**

Table J2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Total Energy Consumption							
Distillate Fuel	7.54	8.80	8.71	9.54	9.40	10.91	10.79
Kerosene	0.15	0.13	0.13	0.12	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	4.51	4.49	5.97	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.08	3.08	3.41	3.44
Motor Gasoline[2]	16.17	17.93	17.88	19.24	19.17	21.57	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.53	1.52	1.70	1.69
Residual Fuel	2.01	1.48	1.29	1.42	1.30	1.42	1.35
Other Petroleum[12]	4.53	4.71	4.68	4.99	5.00	5.35	5.39
Petroleum Subtotal	38.02	41.34	40.92	44.44	44.09	50.45	50.25
Natural Gas	22.21	26.44	25.80	29.00	30.47	36.06	36.33
Metallurgical Coal	0.75	0.67	0.67	0.61	0.61	0.50	0.50
Steam Coal	20.61	23.60	22.54	24.88	16.99	25.70	15.77
Net Coal Coke Imports	0.06	0.12	0.11	0.16	0.15	0.22	0.22
Coal Subtotal	21.42	24.39	23.32	25.64	17.74	26.42	16.49
Nuclear Power	7.79	7.90	7.90	7.74	7.91	6.54	7.10
Renewable Energy[17]	6.54	7.13	7.78	7.91	9.97	8.43	12.33
Methanol (M85)[11]	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.51	0.24	0.37
Total	**96.33**	**107.81**	**106.35**	**115.11**	**110.71**	**128.16**	**122.88**
Energy Use and Related Statistics							
Delivered Energy Use	72.05	80.41	79.96	86.27	85.25	97.57	96.79
Total Energy Use	96.33	107.81	106.35	115.11	110.71	128.16	122.88
Population (millions)	273.13	288.02	288.02	300.17	300.17	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10960	10899	12667	12621	16515	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1660.9	1825.7	1637.4	2051.2	1795.8

[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.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf.
Projections: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Residential	**13.10**	**13.27**	**13.73**	**13.46**	**15.62**	**13.77**	**15.99**
Primary Energy[1]	6.71	7.49	7.37	7.18	7.35	7.08	7.47
Petroleum Products[2]	7.55	9.20	9.15	9.37	9.35	9.47	9.50
Distillate Fuel	6.27	7.45	7.37	7.57	7.56	7.78	7.74
Liquefied Petroleum Gas	10.36	12.60	12.60	12.86	12.80	12.75	12.89
Natural Gas	6.52	7.11	6.97	6.72	6.94	6.65	7.11
Electricity	23.47	22.16	23.76	22.30	28.09	22.44	27.88
Commercial	**13.18**	**12.70**	**13.52**	**12.25**	**15.42**	**12.69**	**15.45**
Primary Energy[1]	5.22	5.57	5.44	5.68	5.86	5.79	6.16
Petroleum Products[2]	4.99	6.13	6.08	6.29	6.26	6.40	6.37
Distillate Fuel	4.37	5.24	5.16	5.36	5.33	5.53	5.48
Residual Fuel	2.63	3.65	3.62	3.71	3.69	3.86	3.84
Natural Gas[3]	5.34	5.55	5.41	5.66	5.87	5.78	6.21
Electricity	21.45	20.26	22.29	18.76	25.55	19.00	25.48
Industrial[4]	**5.27**	**5.76**	**5.88**	**5.67**	**6.42**	**5.90**	**6.61**
Primary Energy	3.91	4.47	4.38	4.49	4.55	4.68	4.87
Petroleum Products[2]	5.54	6.00	5.95	6.13	6.05	6.16	6.17
Distillate Fuel	4.65	5.40	5.33	5.56	5.51	5.73	5.69
Liquefied Petroleum Gas	8.50	7.74	7.72	7.88	7.79	7.76	7.95
Residual Fuel	2.78	3.38	3.35	3.44	3.42	3.59	3.58
Natural Gas[5]	2.79	3.64	3.49	3.50	3.71	3.85	4.29
Metallurgical Coal	1.65	1.58	1.59	1.54	1.55	1.44	1.44
Steam Coal	1.43	1.35	1.35	1.31	1.25	1.21	1.13
Electricity	13.00	12.80	14.24	12.08	17.39	12.22	17.42
Transportation	**8.30**	**9.39**	**9.35**	**9.69**	**9.74**	**9.20**	**9.26**
Primary Energy	8.29	9.38	9.34	9.68	9.71	9.18	9.23
Petroleum Products[2]	8.28	9.37	9.33	9.67	9.71	9.18	9.22
Distillate Fuel[6]	8.22	8.98	8.90	8.95	8.94	8.83	8.82
Jet Fuel[7]	4.70	5.29	5.23	5.49	5.48	5.72	5.71
Motor Gasoline[8]	9.45	10.81	10.78	11.31	11.37	10.60	10.68
Residual Fuel	2.46	3.11	3.10	3.18	3.17	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.06	14.07	14.01	13.70	13.83
Natural Gas[10]	7.02	7.28	7.14	7.21	7.43	7.41	7.82
Ethanol (E85)[11]	14.42	19.21	19.19	19.16	19.25	19.36	19.47
Methanol (M85)[12]	10.38	13.13	12.98	13.83	13.84	14.35	14.38
Electricity	15.59	14.52	15.33	13.62	17.02	13.22	16.12
Average End-Use Energy	**8.49**	**9.17**	**9.36**	**9.22**	**10.16**	**9.21**	**10.08**
Primary Energy	6.31	7.19	7.11	7.35	7.41	7.23	7.36
Electricity	19.41	18.65	20.34	17.99	23.96	18.19	24.01
Electric Generators[13]							
Fossil Fuel Average	1.48	1.64	1.53	1.59	1.94	1.88	2.39
Petroleum Products	2.49	3.61	3.74	3.90	4.14	4.17	4.35
Distillate Fuel	4.04	4.72	4.74	4.87	4.89	5.06	5.10
Residual Fuel	2.40	3.42	3.57	3.65	3.98	3.89	4.20
Natural Gas	2.58	3.44	3.34	3.26	3.67	3.71	4.31
Steam Coal	1.21	1.14	1.08	1.06	0.98	0.98	0.88

Table J3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Average Price to All Users[14]							
Petroleum Products[2]	7.44	8.53	8.51	8.81	8.83	8.49	8.54
Distillate Fuel	7.25	8.14	8.08	8.20	8.20	8.20	8.19
Jet Fuel	4.70	5.29	5.23	5.49	5.48	5.72	5.71
Liquefied Petroleum Gas	8.84	8.63	8.62	8.74	8.67	8.54	8.72
Motor Gasoline[8]	9.45	10.80	10.78	11.31	11.37	10.60	10.68
Residual Fuel	2.47	3.25	3.23	3.33	3.32	3.49	3.48
Natural Gas	4.05	4.72	4.62	4.47	4.68	4.60	5.12
Coal	1.23	1.16	1.10	1.08	1.01	1.00	0.91
Ethanol (E85)[11]	14.42	19.21	19.19	19.16	19.25	19.36	19.47
Methanol (M85)[12]	10.38	13.13	12.98	13.83	13.84	14.35	14.38
Electricity	19.41	18.65	20.34	17.99	23.96	18.19	24.01
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)							
Residential	134.28	153.83	158.22	160.41	180.54	183.27	205.77
Commercial	98.42	114.97	121.71	119.69	146.13	136.41	164.24
Industrial	111.66	127.05	129.45	133.28	151.05	154.57	174.14
Transportation	212.64	273.84	271.64	308.81	308.51	340.45	341.18
Total Non-Renewable Expenditures	556.99	669.69	681.03	722.19	786.24	814.69	885.33
Transportation Renewable Expenditures	0.14	0.42	0.42	0.64	0.63	0.85	0.85
Total Expenditures	**557.13**	**670.11**	**681.45**	**722.82**	**786.87**	**815.54**	**886.18**

[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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2PHF08R_X.D070901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Generation by Fuel Type							
Electric Generators[1]							
Coal	1831	2106	2015	2245	1495	2315	1371
Petroleum	94	43	22	28	13	25	14
Natural Gas[2]	359	583	583	825	1130	1495	1550
Nuclear Power	730	740	740	725	741	613	665
Pumped Storage	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	411	397	533	400	708
Total	**3369**	**3844**	**3770**	**4219**	**3911**	**4847**	**4306**
Non-Utility Generation for Own Use	16	17	22	17	20	17	20
Distributed Generation	0	0	0	1	1	5	2
Cogenerators[4]							
Coal	47	53	52	52	43	52	42
Petroleum	9	10	10	10	10	10	10
Natural Gas	207	237	244	261	326	318	589
Other Gaseous Fuels[5]	4	6	6	7	7	8	9
Renewable Sources[3]	31	34	34	39	39	48	48
Other[6]	5	5	5	5	5	6	6
Total	**303**	**345**	**351**	**373**	**431**	**441**	**703**
Other End-Use Generators[7]	5	5	5	5	5	5	5
Sales to Utilities	151	172	171	180	182	208	264
Generation for Own Use	156	178	185	198	253	238	444
Net Imports[8]	**33**	**57**	**57**	**35**	**49**	**23**	**35**
Electricity Sales by Sector							
Residential	1145	1339	1311	1452	1351	1698	1574
Commercial	1073	1288	1265	1439	1349	1646	1498
Industrial	1058	1142	1119	1222	1136	1395	1197
Transportation	17	26	26	35	34	49	48
Total	**3294**	**3794**	**3721**	**4147**	**3870**	**4788**	**4318**
End-Use Prices (1999 cents per kwh)[9]							
Residential	8.0	7.6	8.1	7.6	9.6	7.7	9.5
Commercial	7.3	6.9	7.6	6.4	8.7	6.5	8.7
Industrial	4.4	4.4	4.9	4.1	5.9	4.2	5.9
Transportation	5.3	5.0	5.2	4.6	5.8	4.5	5.5
All Sectors Average	**6.6**	**6.4**	**6.9**	**6.1**	**8.2**	**6.2**	**8.2**
Prices by Service Category[9] (1999 cents per kwh)							
Generation	4.1	3.8	4.4	3.5	5.4	3.6	5.5
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.1	2.0	2.0
Emissions (million short tons)							
Sulfur Dioxide	13.71	10.38	9.95	9.70	7.30	8.95	6.55
Nitrogen Oxide	5.45	4.30	3.26	4.34	2.45	4.49	2.27

[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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Electric Generators[2]							
Capability							
Coal Steam	305.1	303.9	302.8	318.6	270.3	318.5	257.4
Other Fossil Steam[3]	137.4	127.8	122.7	119.2	104.8	116.9	101.2
Combined Cycle	21.0	53.2	69.5	107.8	150.1	202.2	214.3
Combustion Turbine/Diesel	74.3	123.1	125.3	147.2	128.1	199.5	143.0
Nuclear Power	97.4	97.5	97.5	94.8	96.9	76.3	84.6
Pumped Storage	19.3	19.5	19.5	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	88.8	94.8	96.6	98.0	112.2	99.5	146.5
Distributed Generation[5]	0.0	0.7	0.8	2.5	1.3	11.5	4.1
Total	**743.4**	**820.4**	**834.6**	**907.8**	**883.3**	**1044.2**	**970.8**
Cumulative Planned Additions[6]							
Coal Steam	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
Combined Cycle	0.0	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
Nuclear Power	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
Fuel Cells	0.0	0.0	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	0.0	5.1	5.1	6.7	6.7	8.1	8.1
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**32.0**	**32.0**	**33.7**	**33.7**	**35.3**	**35.3**
Cumulative Unplanned Additions[6]							
Coal Steam	0.0	1.1	0.0	18.9	0.0	20.5	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	19.4	35.7	74.2	116.4	168.6	180.9
Combustion Turbine/Diesel	0.0	38.9	41.9	64.7	46.7	117.2	61.9
Nuclear Power	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
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	2.2	2.0	16.2	2.0	49.1
Distributed Generation[5]	0.0	0.7	0.8	2.5	1.3	11.5	4.1
Total	**0.0**	**60.6**	**80.7**	**162.2**	**180.6**	**319.8**	**295.9**
Cumulative Total Additions	**0.0**	**92.6**	**112.7**	**195.9**	**214.3**	**355.1**	**331.2**
Cumulative Retirements[7]							
Coal Steam	0.0	2.3	2.3	5.4	34.8	7.2	47.7
Other Fossil Steam[3]	0.0	9.9	14.9	18.4	32.8	20.7	36.5
Combined Cycle	0.0	0.0	0.0	0.2	0.1	0.2	0.5
Combustion Turbine/Diesel	0.0	4.4	5.1	6.0	7.1	6.3	7.4
Nuclear Power	0.0	0.0	0.0	2.6	0.6	21.2	12.9
Pumped Storage	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
Renewable Sources	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**16.7**	**22.5**	**32.8**	**75.6**	**55.6**	**105.1**
Cogenerators[8]							
Capability							
Coal	8.4	8.9	8.9	8.6	7.2	8.6	6.8
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	3.0
Natural Gas	34.6	39.9	41.0	43.3	52.3	51.4	89.0
Other Gaseous Fuels	0.2	0.8	0.8	0.9	0.9	1.1	1.1
Renewable Sources[4]	5.4	5.9	5.9	6.8	6.8	8.2	8.3
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**60.3**	**63.3**	**70.9**	**73.2**	**109.1**
Cumulative Additions[6]	**0.0**	**6.8**	**7.9**	**10.9**	**18.5**	**20.7**	**56.7**

Table J5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Other End-Use Generators[9]							
Renewable Sources	1.0	1.1	1.1	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	0.1	0.1	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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Interregional Electricity Trade							
Gross Domestic Firm Power Trade	182.2	125.3	125.3	102.9	102.9	0.0	0.0
Gross Domestic Economy Trade	152.0	202.3	147.4	155.5	63.3	147.9	85.2
Gross Domestic Trade	**334.2**	**327.6**	**272.7**	**258.4**	**166.2**	**147.9**	**85.2**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.8	5905.8	4851.2	4851.2	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4413.9	6468.6	5612.2	4510.4	3164.4	4605.1	4493.0
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11518.0**	**9361.6**	**8015.7**	**4605.1**	**4493.0**
International Electricity Trade							
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	5.8	19.1	0.0	12.1
Economy Imports From Canada and Mexico[1]	21.9	63.5	63.5	45.9	45.9	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**74.1**	**74.1**	**51.7**	**65.0**	**30.6**	**42.7**
Firm Power Exports To Canada and Mexico	9.2	9.7	9.7	8.7	8.7	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.0	7.0	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**16.7**	**16.7**	**16.4**	**16.4**	**7.7**	**7.7**

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

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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Production							
Dry Gas Production[1]	18.67	21.40	20.76	23.43	24.67	29.47	29.52
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.69**	**4.70**	**5.00**	**5.21**	**5.82**	**6.05**
Canada	3.29	4.48	4.49	4.72	4.92	5.43	5.65
Mexico	-0.01	-0.18	-0.18	-0.25	-0.25	-0.40	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.53	0.54	0.79	0.80
Total Supply	**22.15**	**26.20**	**25.58**	**28.49**	**29.94**	**35.35**	**35.63**
Consumption by Sector							
Residential	4.75	5.42	5.45	5.46	5.45	6.07	6.04
Commercial	3.06	3.88	3.91	4.06	4.08	4.32	4.69
Industrial[3]	8.31	8.81	8.82	9.48	9.59	10.53	11.09
Electric Generators[4]	3.64	5.43	4.79	6.81	8.05	11.19	10.53
Lease and Plant Fuel[5]	1.23	1.38	1.34	1.50	1.56	1.87	1.87
Pipeline Fuel	0.64	0.81	0.79	0.88	0.92	1.07	1.08
Transportation[6]	0.02	0.05	0.05	0.09	0.09	0.15	0.15
Total	**21.65**	**25.79**	**25.16**	**28.29**	**29.73**	**35.20**	**35.46**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.20**	**0.21**	**0.14**	**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.
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, M2PHF08R_X.D070901A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2PHF08R_X.D070901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J8. 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	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Source Price							
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.79	2.87	3.09	3.22	3.74
Average Import Price	2.29	2.95	2.92	2.64	2.75	2.72	2.88
Average[2]	**2.11**	**2.96**	**2.82**	**2.82**	**3.03**	**3.13**	**3.58**
Delivered Prices							
Residential	6.69	7.31	7.16	6.91	7.12	6.83	7.31
Commercial	5.49	5.70	5.56	5.82	6.03	5.93	6.38
Industrial[3]	2.87	3.74	3.59	3.59	3.81	3.95	4.41
Electric Generators[4]	2.63	3.50	3.40	3.32	3.74	3.78	4.39
Transportation[5]	7.21	7.48	7.33	7.40	7.63	7.61	8.03
Average[6]	**4.15**	**4.84**	**4.74**	**4.59**	**4.80**	**4.72**	**5.25**
Transmission & Distribution Margins[7]							
Residential	4.58	4.35	4.34	4.08	4.09	3.70	3.72
Commercial	3.37	2.74	2.74	2.99	3.00	2.81	2.80
Industrial[3]	0.76	0.78	0.77	0.77	0.78	0.82	0.83
Electric Generators[4]	0.52	0.54	0.59	0.49	0.71	0.65	0.81
Transportation[5]	5.10	4.51	4.51	4.58	4.60	4.48	4.45
Average[6]	**2.04**	**1.88**	**1.92**	**1.76**	**1.77**	**1.59**	**1.67**
Transmission & Distribution Revenue (billion 1999 dollars)							
Residential	21.77	23.57	23.68	22.30	22.31	22.48	22.51
Commercial	10.32	10.63	10.71	12.16	12.24	12.12	13.11
Industrial[3]	6.28	6.86	6.81	7.26	7.46	8.65	9.20
Electric Generators[4]	1.88	2.94	2.81	3.36	5.72	7.24	8.50
Transportation[5]	0.08	0.24	0.24	0.41	0.41	0.68	0.66
Total	**40.32**	**44.25**	**44.24**	**45.49**	**48.14**	**51.18**	**53.97**

[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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J9. Oil and Gas Supply

Production and Supply	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Crude Oil							
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**21.43**	**21.43**	**20.73**	**20.83**	**21.47**	**21.46**
Production (million barrels per day)[2]							
U.S. Total	**5.88**	**5.66**	**5.67**	**5.32**	**5.30**	**5.25**	**5.32**
Lower 48 Onshore	3.27	2.81	2.81	2.52	2.51	2.75	2.81
Conventional	2.59	2.18	2.17	1.81	1.81	1.98	2.04
Enhanced Oil Recovery	0.68	0.63	0.63	0.70	0.70	0.76	0.78
Lower 48 Offshore	1.56	2.06	2.07	2.16	2.15	1.87	1.87
Alaska	1.05	0.79	0.79	0.65	0.65	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.75**	**15.76**	**14.55**	**14.46**	**14.11**	**14.28**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.79**	**2.87**	**3.09**	**3.22**	**3.74**
Production (trillion cubic feet)[3]							
U.S. Total	**18.67**	**21.40**	**20.76**	**23.43**	**24.67**	**29.47**	**29.52**
Lower 48 Onshore	12.83	14.46	13.93	16.71	17.39	21.31	21.41
Associated-Dissolved[4]	1.80	1.51	1.51	1.32	1.32	1.39	1.42
Non-Associated	11.03	12.95	12.42	15.39	16.07	19.91	19.99
Conventional	6.64	7.67	7.36	7.93	8.46	11.14	11.34
Unconventional	4.39	5.27	5.05	7.45	7.61	8.78	8.65
Lower 48 Offshore	5.43	6.47	6.37	6.22	6.78	7.59	7.55
Associated-Dissolved[4]	0.93	1.06	1.06	1.09	1.09	1.04	1.03
Non-Associated	4.50	5.41	5.30	5.13	5.69	6.56	6.52
Alaska	0.42	0.47	0.46	0.50	0.50	0.57	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**167.88**	**170.18**	**185.55**	**178.72**	**200.71**	**185.71**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.93**	**28.87**	**27.85**	**29.86**	**30.52**	**39.36**	**36.17**

[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.

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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Production[1]							
Appalachia	433	426	415	421	314	396	272
Interior	185	182	174	180	139	161	123
West	486	624	588	694	441	783	441
East of the Mississippi	559	561	544	557	430	524	379
West of the Mississippi	544	672	633	738	465	817	457
Total	**1103**	**1233**	**1177**	**1295**	**895**	**1340**	**836**
Net Imports							
Imports	9	16	12	17	9	20	9
Exports	58	60	60	58	60	56	57
Total	**-49**	**-44**	**-48**	**-40**	**-51**	**-36**	**-48**
Total Supply[2]	**1054**	**1189**	**1129**	**1254**	**844**	**1304**	**788**
Consumption by Sector							
Residential and Commercial	5	5	5	5	5	5	5
Industrial[3]	79	82	82	83	80	86	85
Coke Plants	28	25	25	23	23	19	19
Electric Generators[4]	921	1077	1020	1145	738	1196	680
Total	**1032**	**1189**	**1132**	**1256**	**846**	**1306**	**789**
Discrepancy and Stock Change[5]	**21**	**-1**	**-2**	**-2**	**-2**	**-2**	**-1**
Average Minemouth Price							
(1999 dollars per short ton)	17.17	15.05	14.86	14.08	14.14	12.87	12.68
(1999 dollars per million Btu)	0.82	0.73	0.72	0.69	0.67	0.64	0.61
Delivered Prices (1999 dollars per short ton)[6]							
Industrial	31.39	29.67	29.53	28.61	27.20	26.50	24.56
Coke Plants	44.28	42.39	42.66	41.36	41.61	38.52	38.64
Electric Generators							
(1999 dollars per short ton)	24.73	22.90	21.79	21.28	19.98	19.41	17.87
(1999 dollars per million Btu)	1.21	1.14	1.08	1.06	0.98	0.98	0.88
Average	**25.77**	**23.78**	**22.82**	**22.13**	**21.25**	**20.15**	**19.09**
Exports[7]	37.44	36.39	36.49	35.66	34.84	33.09	32.25

[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.

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 M2BASE.D060801A, M2PHF08R.D060801A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Electric Generators[1] (excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	78.77	79.26	79.34	79.38	80.69	79.38	80.69
Geothermal[2]	2.87	3.43	4.87	4.93	8.88	4.95	10.11
Municipal Solid Waste[3]	2.61	2.96	3.24	3.42	4.40	3.93	4.94
Wood and Other Biomass[4]	1.57	1.75	1.75	2.12	3.05	2.45	22.08
Solar Thermal	0.33	0.35	0.35	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.21	0.21	0.54	0.54
Wind	2.66	6.92	6.92	7.52	14.59	7.76	27.69
Total	**88.83**	**94.75**	**96.56**	**97.98**	**112.22**	**99.49**	**146.52**
Generation (billion kilowatthours)							
Conventional Hydropower	309.55	301.20	301.46	301.13	305.53	300.07	304.40
Geothermal[2]	13.21	18.34	30.27	30.94	63.30	31.16	73.40
Municipal Solid Waste[3]	18.12	20.68	22.93	23.88	31.57	27.76	35.62
Wood and Other Biomass[4]	9.02	14.94	39.23	21.30	91.79	19.78	213.35
Dedicated Plants	7.73	9.16	9.18	11.36	17.61	13.82	144.89
Cofiring	1.29	5.78	30.06	9.94	74.18	5.95	68.45
Solar Thermal	0.89	0.96	0.96	1.11	1.11	1.37	1.37
Solar Photovoltaic	0.03	0.20	0.20	0.51	0.51	1.36	1.36
Wind	4.61	16.30	16.30	18.16	39.00	18.83	78.32
Total	**355.43**	**372.61**	**411.35**	**397.03**	**532.81**	**400.32**	**707.82**
Cogenerators[5]							
Net Summer Capability							
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	5.17	5.18	6.06	6.08	7.54	7.56
Total	**5.35**	**5.87**	**5.88**	**6.76**	**6.78**	**8.24**	**8.26**
Generation (billion kilowatthours)							
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04
Biomass	27.08	29.92	30.00	35.01	35.02	43.52	43.57
Total	**31.12**	**33.97**	**34.05**	**39.05**	**39.06**	**47.57**	**47.61**
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
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.10	0.10	0.35	0.35	0.35	0.35
Total	**1.00**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)							
Conventional Hydropower[7]	4.57	4.44	4.44	4.43	4.43	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.20	0.20	0.75	0.75	0.75	0.76
Total	**4.59**	**4.64**	**4.64**	**5.18**	**5.18**	**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.

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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Marketed Renewable Energy[2]							
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.43**
Wood	0.41	0.42	0.42	0.42	0.42	0.44	0.43
Commercial	**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
Industrial[3]	**2.15**	**2.42**	**2.41**	**2.64**	**2.63**	**3.08**	**3.08**
Conventional Hydroelectric	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
Biomass	1.97	2.23	2.22	2.46	2.44	2.90	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.22**	**0.22**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.19	0.20	0.21	0.21
Electric Generators[5]	**3.88**	**4.19**	**4.85**	**4.73**	**6.80**	**4.78**	**8.69**
Conventional Hydroelectric	3.19	3.10	3.10	3.10	3.14	3.08	3.13
Geothermal	0.28	0.44	0.83	0.85	1.85	0.85	2.20
Municipal Solid Waste[6]	0.25	0.28	0.31	0.32	0.43	0.38	0.48
Biomass	0.12	0.18	0.43	0.26	0.96	0.25	2.04
Dedicated Plants	0.10	0.11	0.10	0.14	0.18	0.17	1.39
Cofiring	0.02	0.07	0.33	0.12	0.77	0.07	0.66
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.17	0.17	0.19	0.40	0.19	0.81
Total Marketed Renewable Energy	**6.64**	**7.31**	**7.96**	**8.10**	**10.16**	**8.62**	**12.53**
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.03**
Solar Hot Water Heating	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ethanol							
From Corn	0.12	0.19	0.18	0.20	0.20	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.02	0.02	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.22**	**0.22**	**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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections 2005 Reference	2005 Integrated Moderate Target	2010 Reference	2010 Integrated Moderate Target	2020 Reference	2020 Integrated Moderate Target
Residential							
Petroleum	26.0	26.5	26.5	24.5	24.6	23.2	23.5
Natural Gas	69.5	80.2	80.6	80.8	80.6	89.8	89.4
Coal	1.1	1.2	1.2	1.3	1.3	1.3	1.2
Electricity	193.4	227.1	212.2	242.6	176.9	275.6	185.9
Total	**290.1**	**335.0**	**320.6**	**349.2**	**283.4**	**389.8**	**300.1**
Commercial							
Petroleum	13.7	11.8	11.8	12.0	12.0	12.1	12.3
Natural Gas	45.4	57.4	57.8	60.1	60.3	63.9	69.3
Coal	1.7	1.7	1.7	1.8	1.8	1.9	1.9
Electricity	181.3	218.4	204.8	240.4	176.6	267.1	177.0
Total	**242.1**	**289.4**	**276.1**	**314.3**	**250.8**	**345.0**	**260.6**
Industrial[1]							
Petroleum	104.2	99.2	98.5	105.3	105.5	113.6	114.7
Natural Gas[2]	141.6	148.4	148.1	159.8	162.4	180.3	189.0
Coal	55.9	65.8	65.6	65.6	63.7	65.8	65.1
Electricity	178.8	193.6	181.2	204.1	148.7	226.4	141.4
Total	**480.4**	**507.0**	**493.3**	**534.8**	**480.3**	**586.1**	**510.2**
Transportation							
Petroleum[3]	485.8	556.3	554.1	607.2	603.5	704.2	700.9
Natural Gas[4]	9.5	12.8	12.5	14.4	14.9	18.1	18.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.2	5.8	4.5	7.9	5.7
Total[3]	**498.2**	**573.6**	**570.8**	**627.5**	**623.0**	**730.2**	**724.9**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	629.7	693.8	690.9	749.0	745.6	853.1	851.4
Natural Gas	266.0	298.8	299.0	315.1	318.2	352.0	365.9
Coal	58.8	68.8	68.5	68.8	66.8	69.0	68.3
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	643.6	602.4	692.8	506.7	777.0	510.1
Total[3]	**1510.8**	**1705.0**	**1660.9**	**1825.7**	**1637.4**	**2051.2**	**1795.8**
Electric Generators[6]							
Petroleum	20.0	9.4	4.5	5.8	2.6	5.2	2.6
Natural Gas	45.8	79.6	70.3	100.0	118.1	164.1	154.5
Coal	490.5	554.6	527.6	587.0	386.1	607.7	352.9
Total	**556.3**	**643.6**	**602.4**	**692.8**	**506.7**	**777.0**	**510.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	649.7	703.1	695.4	754.8	748.1	858.3	854.1
Natural Gas	311.8	378.4	369.3	415.0	436.3	516.2	520.4
Coal	549.3	623.3	596.2	655.8	452.9	676.7	421.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1705.0**	**1660.9**	**1825.7**	**1637.4**	**2051.2**	**1795.8**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.8**	**6.1**	**5.5**	**6.3**	**5.5**

[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.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Table J14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections					
		2005		2010		2020	
		Reference	Integrated Moderate Target	Reference	Integrated Moderate Target	Reference	Integrated Moderate Target
Emissions							
Nitrogen Oxide (million tons)	5.45	4.30	3.26	4.34	2.45	4.49	2.27
Sulfur Dioxide (million tons)	13.71	10.38	9.95	9.70	7.30	8.95	6.55
Mercury (tons)	43.60	45.24	41.95	45.60	20.00	45.07	20.00
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	602.45	692.78	506.70	776.99	510.12
Allowance Prices							
Nitrogen Oxide (1999 dollars per ton)	0	4352	139	4391	0	5037	0
Sulfur Dioxide (1999 dollars per ton)	0	190	153	187	43	241	30
Mercury (million 1999 dollars per ton)	0	0	0	0	111	0	90
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	44	0	111	0	119
Retrofits (gigawatts)							
Scrubber [1]	0.0	6.5	3.7	7.1	4.3	14.8	4.3
Combustion	0.0	39.9	38.6	42.1	41.6	46.1	44.4
SCR Post-combustion	0.0	92.8	86.1	92.9	86.1	93.0	86.4
SNCR Post-combustion	0.0	25.2	26.3	26.3	26.5	43.4	26.6
Coal Production by Sulfur Category (million tons)							
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	586	642	448	721	432
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	413	464	312	440	274
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	178	188	136	179	130

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
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 M2BASE.D060801A, M2PHF08R_X.D070901A.

Appendix K

Tables for Integrated Cost of Service and Integrated High Gas Price Cases

Table K1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Production										
Crude Oil and Lease Condensate	12.45	11.98	12.00	11.81	11.27	11.23	10.77	11.12	11.57	10.70
Natural Gas Plant Liquids	2.62	3.12	3.07	3.03	3.37	3.73	3.72	4.16	4.30	3.81
Dry Natural Gas	19.16	21.95	21.61	21.36	24.04	26.63	26.56	30.24	31.24	27.63
Coal	23.08	25.45	24.09	24.29	26.55	13.89	14.75	27.16	12.41	14.30
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.95	7.95	6.54	7.41	7.51
Renewable Energy[1]	6.53	7.13	8.26	8.12	7.90	10.16	10.08	8.42	12.06	12.31
Other[2]	1.65	0.35	0.54	0.58	0.31	0.30	0.30	0.33	0.33	0.33
Total	**73.29**	**77.88**	**77.48**	**77.11**	**81.19**	**73.88**	**74.13**	**87.97**	**79.32**	**76.60**
Imports										
Crude Oil[3]	18.96	21.42	21.41	21.45	22.38	22.47	22.89	25.82	25.68	26.74
Petroleum Products[4]	4.14	6.28	5.85	5.98	8.65	8.02	8.13	10.80	10.63	13.18
Natural Gas	3.63	5.13	5.17	5.13	5.55	7.11	6.14	6.59	8.61	7.19
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.89	0.89	0.96	0.81	0.81
Total	**27.37**	**33.93**	**33.45**	**33.58**	**37.54**	**38.49**	**38.04**	**44.18**	**45.73**	**47.91**
Exports										
Petroleum[6]	1.98	1.73	1.75	1.75	1.69	1.67	1.64	1.85	1.86	2.10
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.12	0.43	0.63	0.12	0.63
Coal	1.48	1.51	1.51	1.51	1.45	1.43	1.44	1.41	1.58	1.51
Total	**3.62**	**3.57**	**3.58**	**3.59**	**3.58**	**3.21**	**3.51**	**3.89**	**3.56**	**4.25**
Discrepancy[7]	**0.69**	**0.43**	**0.53**	**0.56**	**0.04**	**0.11**	**0.14**	**0.11**	**0.21**	**0.36**
Consumption										
Petroleum Products[8]	38.02	41.34	40.94	40.90	44.44	44.20	44.27	50.45	50.63	52.46
Natural Gas	22.21	26.44	26.14	25.85	29.00	33.42	32.08	36.06	39.55	34.02
Coal	21.42	24.39	22.96	23.14	25.64	12.79	13.62	26.42	11.24	13.21
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.95	7.95	6.54	7.41	7.51
Renewable Energy[1]	6.54	7.13	8.26	8.13	7.91	10.17	10.09	8.43	12.07	12.32
Other[9]	0.35	0.61	0.61	0.61	0.38	0.52	0.52	0.25	0.38	0.38
Total	**96.33**	**107.81**	**106.82**	**106.54**	**115.11**	**109.05**	**108.52**	**128.16**	**121.27**	**119.90**
Net Imports - Petroleum	**21.12**	**25.96**	**25.51**	**25.68**	**29.34**	**28.83**	**29.38**	**34.78**	**34.45**	**37.82**
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	2.96	2.84	2.81	2.87	3.96	4.08	3.22	4.15	5.05
Coal Minemouth Price (dollars per ton)	17.17	15.05	14.77	14.97	14.08	14.39	14.67	12.87	13.37	13.95
Average Electric Price (cents per Kwh)	6.6	6.4	6.5	6.7	6.1	7.7	8.6	6.2	7.9	9.3

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.87	0.87	0.87	0.80	0.81	0.81	0.76	0.77	0.77
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	0.45	0.45	0.45	0.42	0.42	0.42	0.40	0.41	0.40
Petroleum Subtotal	1.42	1.40	1.40	1.40	1.30	1.30	1.30	1.23	1.25	1.24
Natural Gas	4.88	5.57	5.59	5.60	5.61	5.42	5.42	6.23	6.02	5.90
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	0.44	0.42	0.42
Electricity	3.91	4.57	4.53	4.50	4.95	4.70	4.54	5.79	5.47	5.18
Delivered Energy	**10.66**	**12.01**	**12.00**	**11.97**	**12.34**	**11.89**	**11.74**	**13.74**	**13.22**	**12.79**
Electricity Related Losses	8.44	9.67	9.41	9.35	10.10	8.38	8.27	10.85	8.97	8.92
Total	**19.10**	**21.68**	**21.41**	**21.32**	**22.44**	**20.27**	**20.01**	**24.59**	**22.19**	**21.71**
Commercial										
Distillate Fuel	0.36	0.37	0.37	0.37	0.38	0.39	0.39	0.37	0.45	0.47
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	0.60	0.61	0.60	0.62	0.64	0.63	0.62	0.70	0.72
Natural Gas	3.14	3.99	4.00	4.01	4.17	3.99	4.01	4.44	4.45	4.54
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	4.39	4.38	4.34	4.91	4.69	4.56	5.62	5.23	4.92
Delivered Energy	**7.55**	**9.13**	**9.13**	**9.10**	**9.85**	**9.47**	**9.35**	**10.83**	**10.54**	**10.34**
Electricity Related Losses	7.91	9.30	9.09	9.02	10.01	8.37	8.29	10.51	8.58	8.48
Total	**15.46**	**18.44**	**18.22**	**18.13**	**19.86**	**17.85**	**17.64**	**21.34**	**19.12**	**18.81**
Industrial[4]										
Distillate Fuel	1.13	1.22	1.21	1.21	1.31	1.30	1.30	1.49	1.49	1.51
Liquefied Petroleum Gas	2.32	2.45	2.43	2.43	2.53	2.58	2.59	2.85	3.01	3.21
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.16	0.16	0.16	0.25	0.37	0.37	0.28	0.39	0.42
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.44	4.42	4.42	4.71	4.71	4.73	5.02	5.09	5.27
Petroleum Subtotal	9.45	9.86	9.81	9.79	10.57	10.73	10.76	11.63	11.95	12.39
Natural Gas[6]	9.80	10.46	10.43	10.43	11.27	11.07	11.11	12.73	12.65	12.15
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	1.81	1.80	1.80	1.83	1.74	1.79	1.87	1.83	1.90
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.21
Coal Subtotal	2.54	2.59	2.58	2.59	2.59	2.50	2.54	2.60	2.55	2.62
Renewable Energy[7]	2.15	2.42	2.41	2.41	2.64	2.63	2.63	3.08	3.08	3.08
Electricity	3.61	3.90	3.85	3.83	4.17	3.99	3.88	4.76	4.32	4.02
Delivered Energy	**27.56**	**29.23**	**29.08**	**29.05**	**31.24**	**30.92**	**30.93**	**34.80**	**34.55**	**34.25**
Electricity Related Losses	7.80	8.25	8.00	7.96	8.50	7.12	7.07	8.91	7.08	6.93
Total	**35.36**	**37.48**	**37.07**	**37.01**	**39.74**	**38.04**	**37.99**	**43.71**	**41.64**	**41.18**

Table K2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Transportation										
Distillate Fuel	5.13	6.28	6.24	6.23	7.00	6.85	6.86	8.22	8.09	8.09
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.48	5.97	5.96	5.96
Motor Gasoline[2]	15.92	17.67	17.64	17.64	18.97	18.90	18.89	21.26	21.21	21.19
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.85	0.85	0.87	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	0.05
Other Petroleum[9]	0.26	0.30	0.29	0.29	0.31	0.31	0.30	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.03	28.94	28.92	31.68	31.44	31.42	36.73	36.54	36.50
Pipeline Fuel Natural Gas	0.66	0.83	0.82	0.81	0.91	1.01	1.00	1.10	1.15	1.06
Compressed Natural Gas	0.02	0.06	0.05	0.05	0.09	0.09	0.09	0.16	0.15	0.14
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	0.01	0.00	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**	**30.03**	**29.93**	**29.90**	**32.83**	**32.69**	**32.66**	**38.20**	**38.05**	**37.92**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.21	0.21	0.31	0.27	0.28
Total	**26.41**	**30.22**	**30.11**	**30.09**	**33.07**	**32.90**	**32.88**	**38.51**	**38.32**	**38.20**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.48	8.74	8.69	8.68	9.49	9.36	9.36	10.85	10.80	10.84
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.14	3.15	3.41	3.57	3.76
Motor Gasoline[2]	16.17	17.93	17.90	17.89	19.24	19.17	19.16	21.57	21.52	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.10	1.10	1.10	1.20	1.31	1.32	1.24	1.35	1.37
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	4.99	5.01	5.35	5.42	5.60
Petroleum Subtotal	37.01	40.90	40.75	40.72	44.16	44.11	44.12	50.21	50.45	50.85
Natural Gas[6]	18.50	20.91	20.90	20.91	22.05	21.57	21.63	24.66	24.42	23.79
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	1.95	1.86	1.91	2.00	1.96	2.02
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.21
Coal Subtotal	2.65	2.71	2.70	2.70	2.71	2.62	2.67	2.72	2.67	2.74
Renewable Energy[13]	2.65	2.94	2.93	2.93	3.18	3.17	3.17	3.65	3.63	3.62
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	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	12.95	12.85	12.75	14.15	13.50	13.10	16.34	15.19	14.29
Delivered Energy	**72.05**	**80.41**	**80.14**	**80.02**	**86.27**	**84.97**	**84.68**	**97.57**	**96.37**	**95.29**
Electricity Related Losses	24.29	27.40	26.68	26.52	28.84	24.08	23.84	30.58	24.90	24.61
Total	**96.33**	**107.81**	**106.82**	**106.54**	**115.11**	**109.05**	**108.52**	**128.16**	**121.27**	**119.90**
Electric Generators[14]										
Distillate Fuel	0.06	0.06	0.03	0.03	0.06	0.03	0.09	0.06	0.10	1.51
Residual Fuel	0.96	0.38	0.16	0.15	0.22	0.07	0.07	0.19	0.08	0.09
Petroleum Subtotal	1.02	0.44	0.19	0.18	0.28	0.10	0.15	0.25	0.18	1.61
Natural Gas	3.71	5.53	5.25	4.95	6.94	11.85	10.45	11.40	15.13	10.23
Steam Coal	18.77	21.68	20.26	20.44	22.93	10.17	10.95	23.70	8.56	10.47
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.95	7.95	6.54	7.41	7.51
Renewable Energy[15]	3.88	4.19	5.33	5.19	4.73	7.00	6.93	4.78	8.44	8.70
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.51	0.51	0.24	0.37	0.37
Total	**35.52**	**40.35**	**39.53**	**39.27**	**42.99**	**37.58**	**36.94**	**46.92**	**40.09**	**38.90**

Table K2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections 2005 Reference	2005 Integrated Cost of Service	2005 Integrated High Gas Price	2010 Reference	2010 Integrated Cost of Service	2010 Integrated High Gas Price	2020 Reference	2020 Integrated Cost of Service	2020 Integrated High Gas Price
Total Energy Consumption										
Distillate Fuel	7.54	8.80	8.72	8.71	9.54	9.39	9.44	10.91	10.90	12.36
Kerosene	0.15	0.13	0.13	0.13	0.12	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.88	3.88	4.51	4.48	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.02	3.00	3.00	3.08	3.14	3.15	3.41	3.57	3.76
Motor Gasoline[2]	16.17	17.93	17.90	17.89	19.24	19.17	19.16	21.57	21.52	21.50
Petrochemical Feedstock	1.29	1.36	1.36	1.36	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	2.01	1.48	1.26	1.24	1.42	1.38	1.38	1.42	1.43	1.47
Other Petroleum[12]	4.53	4.71	4.69	4.69	4.99	4.99	5.01	5.35	5.42	5.60
Petroleum Subtotal	38.02	41.34	40.94	40.90	44.44	44.20	44.27	50.45	50.63	52.46
Natural Gas	22.21	26.44	26.14	25.85	29.00	33.42	32.08	36.06	39.55	34.02
Metallurgical Coal	0.75	0.67	0.67	0.67	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.61	23.60	22.17	22.36	24.88	12.04	12.86	25.70	10.52	12.50
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.21
Coal Subtotal	21.42	24.39	22.96	23.14	25.64	12.79	13.62	26.42	11.24	13.21
Nuclear Power	7.79	7.90	7.90	7.90	7.74	7.95	7.95	6.54	7.41	7.51
Renewable Energy[17]	6.54	7.13	8.26	8.13	7.91	10.17	10.09	8.43	12.07	12.32
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.01	0.00	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	0.51	0.51	0.24	0.37	0.37
Total	**96.33**	**107.81**	**106.82**	**106.54**	**115.11**	**109.05**	**108.52**	**128.16**	**121.27**	**119.90**
Energy Use and Related Statistics										
Delivered Energy Use	72.05	80.41	80.14	80.02	86.27	84.97	84.68	97.57	96.37	95.29
Total Energy Use	96.33	107.81	106.82	106.54	115.11	109.05	108.52	128.16	121.27	119.90
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	10960	10911	10904	12667	12614	12604	16515	16523	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1705.0	1656.4	1656.1	1825.7	1555.1	1558.0	2051.2	1714.0	1720.0

[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.
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, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.pdf. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Residential	**13.10**	**13.27**	**13.33**	**13.57**	**13.46**	**15.58**	**16.69**	**13.77**	**15.84**	**17.86**
Primary Energy[1]	6.71	7.49	7.41	7.39	7.18	7.96	8.03	7.08	7.80	8.46
Petroleum Products[2]	7.55	9.20	9.14	9.15	9.37	9.34	9.36	9.47	9.54	9.79
Distillate Fuel	6.27	7.45	7.37	7.37	7.57	7.54	7.56	7.78	7.76	7.85
Liquefied Petroleum Gas	10.36	12.60	12.58	12.60	12.86	12.85	12.85	12.75	12.98	13.61
Natural Gas	6.52	7.11	7.02	7.00	6.72	7.69	7.77	6.65	7.49	8.24
Electricity	23.47	22.16	22.53	23.27	22.30	26.58	29.61	22.44	26.61	30.91
Commercial	**13.18**	**12.70**	**12.81**	**13.21**	**12.25**	**15.20**	**16.55**	**12.69**	**15.51**	**17.71**
Primary Energy[1]	5.22	5.57	5.48	5.46	5.68	6.48	6.55	5.79	6.48	7.11
Petroleum Products[2]	4.99	6.13	6.07	6.08	6.29	6.21	6.23	6.40	6.30	6.46
Distillate Fuel	4.37	5.24	5.16	5.17	5.36	5.30	5.32	5.53	5.49	5.64
Residual Fuel	2.63	3.65	3.61	3.61	3.71	3.69	3.69	3.86	3.84	3.84
Natural Gas[3]	5.34	5.55	5.46	5.44	5.66	6.61	6.70	5.78	6.60	7.31
Electricity	21.45	20.26	20.63	21.57	18.76	23.94	26.89	19.00	24.53	29.19
Industrial[4]	**5.27**	**5.76**	**5.74**	**5.81**	**5.67**	**6.61**	**6.90**	**5.90**	**6.87**	**7.61**
Primary Energy	3.91	4.47	4.40	4.39	4.49	4.91	4.94	4.68	5.13	5.59
Petroleum Products[2]	5.54	6.00	5.95	5.95	6.13	6.04	6.04	6.16	6.25	6.53
Distillate Fuel	4.65	5.40	5.33	5.33	5.56	5.48	5.49	5.73	5.70	5.89
Liquefied Petroleum Gas	8.50	7.74	7.72	7.72	7.88	7.91	7.93	7.76	8.11	8.79
Residual Fuel	2.78	3.38	3.35	3.34	3.44	3.33	3.33	3.59	3.49	3.50
Natural Gas[5]	2.79	3.64	3.55	3.52	3.50	4.53	4.61	3.85	4.73	5.49
Metallurgical Coal	1.65	1.58	1.59	1.58	1.54	1.52	1.54	1.44	1.44	1.45
Steam Coal	1.43	1.35	1.34	1.34	1.31	1.16	1.18	1.21	1.06	1.10
Electricity	13.00	12.80	13.12	13.72	12.08	16.20	18.32	12.22	16.92	20.24
Transportation	**8.30**	**9.39**	**9.34**	**9.35**	**9.69**	**9.69**	**9.70**	**9.20**	**9.22**	**9.19**
Primary Energy	8.29	9.38	9.32	9.33	9.68	9.66	9.67	9.18	9.18	9.15
Petroleum Products[2]	8.28	9.37	9.32	9.33	9.67	9.65	9.67	9.18	9.18	9.14
Distillate Fuel[6]	8.22	8.98	8.90	8.90	8.95	8.93	8.97	8.83	8.81	8.94
Jet Fuel[7]	4.70	5.29	5.23	5.25	5.49	5.48	5.53	5.72	5.72	5.72
Motor Gasoline[8]	9.45	10.81	10.75	10.76	11.31	11.28	11.28	10.60	10.60	10.49
Residual Fuel	2.46	3.11	3.10	3.09	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.07	14.04	14.05	14.07	14.15	14.14	13.70	14.02	14.51
Natural Gas[10]	7.02	7.28	7.19	7.16	7.21	8.19	8.27	7.41	8.18	8.75
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.29	19.29	19.36	19.48	19.52
Methanol (M85)[12]	10.38	13.13	13.03	13.00	13.83	14.37	14.36	14.35	14.35	14.32
Electricity	15.59	14.52	15.08	15.03	13.62	17.03	17.32	13.22	17.05	17.73
Average End-Use Energy	**8.49**	**9.17**	**9.16**	**9.28**	**9.22**	**10.17**	**10.57**	**9.21**	**10.13**	**10.86**
Primary Energy	6.31	7.19	7.13	7.12	7.35	7.63	7.65	7.23	7.49	7.73
Electricity	19.41	18.65	19.01	19.77	17.99	22.51	25.21	18.19	23.03	27.16
Electric Generators[13]										
Fossil Fuel Average	1.48	1.64	1.58	1.54	1.59	2.96	2.80	1.88	3.44	3.30
Petroleum Products	2.49	3.61	3.80	3.84	3.90	4.49	4.60	4.17	4.72	5.19
Distillate Fuel	4.04	4.72	4.74	4.75	4.87	4.78	4.81	5.06	4.97	5.24
Residual Fuel	2.40	3.42	3.63	3.65	3.65	4.34	4.32	3.89	4.41	4.27
Natural Gas	2.58	3.44	3.46	3.41	3.26	4.71	4.74	3.71	4.90	5.48
Steam Coal	1.21	1.14	1.07	1.07	1.06	0.92	0.94	0.98	0.84	0.89

Table K3. Energy Prices by Sector and Source (Continued)

(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Average Price to All Users[14]										
Petroleum Products[2]	7.44	8.53	8.51	8.52	8.81	8.78	8.78	8.49	8.51	8.46
Distillate Fuel	7.25	8.14	8.08	8.08	8.20	8.17	8.18	8.20	8.14	7.92
Jet Fuel	4.70	5.29	5.23	5.25	5.49	5.48	5.53	5.72	5.72	5.72
Liquefied Petroleum Gas	8.84	8.63	8.61	8.62	8.74	8.76	8.77	8.54	8.85	9.46
Motor Gasoline[8]	9.45	10.80	10.75	10.76	11.31	11.28	11.28	10.60	10.60	10.49
Residual Fuel	2.47	3.25	3.23	3.23	3.33	3.31	3.31	3.49	3.47	3.47
Natural Gas	4.05	4.72	4.67	4.65	4.47	5.44	5.53	4.60	5.50	6.29
Coal	1.23	1.16	1.09	1.10	1.08	0.96	0.97	1.00	0.88	0.92
Ethanol (E85)[11]	14.42	19.21	19.19	19.19	19.16	19.29	19.29	19.36	19.48	19.52
Methanol (M85)[12]	10.38	13.13	13.03	13.00	13.83	14.37	14.36	14.35	14.35	14.32
Electricity	19.41	18.65	19.01	19.77	17.99	22.51	25.21	18.19	23.03	27.16
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.28	153.83	154.30	156.69	160.41	178.69	188.86	183.27	202.79	220.93
Commercial	98.42	114.97	115.95	119.15	119.69	142.78	153.36	136.41	162.17	181.61
Industrial	111.66	127.05	126.12	127.89	133.28	154.71	162.04	154.57	179.74	199.28
Transportation	212.64	273.84	271.38	271.53	308.81	306.29	306.53	340.45	339.36	337.85
Total Non-Renewable Expenditures	556.99	669.69	667.75	675.26	722.19	782.47	810.79	814.69	884.05	939.67
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.64	0.63	0.63	0.85	0.85	0.84
Total Expenditures	**557.13**	**670.11**	**668.17**	**675.68**	**722.82**	**783.10**	**811.41**	**815.54**	**884.90**	**940.51**

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Generation by Fuel Type										
Electric Generators[1]										
Coal	1831	2106	1979	1995	2245	1003	1079	2315	852	1038
Petroleum	94	43	19	18	28	12	20	25	24	236
Natural Gas[2]	359	583	656	616	825	1740	1525	1495	2243	1503
Nuclear Power	730	740	740	740	725	744	744	613	694	704
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	355	373	425	419	397	515	514	400	657	687
Total	**3369**	**3844**	**3819**	**3788**	**4219**	**4014**	**3882**	**4847**	**4468**	**4167**
Non-Utility Generation for Own Use	16	17	21	21	17	20	20	17	19	19
Distributed Generation	0	0	0	0	1	1	1	5	1	1
Cogenerators[4]										
Coal	47	53	52	52	52	42	45	52	42	44
Petroleum	9	10	10	10	10	10	10	10	10	14
Natural Gas	207	237	238	242	261	285	313	318	477	594
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	9	9
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	47
Other[6]	5	5	5	5	5	5	5	6	6	6
Total	**303**	**345**	**346**	**350**	**373**	**389**	**419**	**441**	**591**	**714**
Other End-Use Generators	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	151	172	170	170	180	171	178	208	238	270
Generation for Own Use	156	178	181	184	198	223	246	238	359	449
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**49**	**49**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1145	1339	1329	1318	1452	1376	1331	1698	1604	1518
Commercial	1073	1288	1283	1272	1439	1375	1335	1646	1534	1443
Industrial	1058	1142	1129	1122	1222	1170	1138	1395	1267	1179
Transportation	17	26	26	26	35	34	34	49	48	48
Total	**3294**	**3794**	**3767**	**3738**	**4147**	**3956**	**3838**	**4788**	**4453**	**4188**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.6	7.7	7.9	7.6	9.1	10.1	7.7	9.1	10.5
Commercial	7.3	6.9	7.0	7.4	6.4	8.2	9.2	6.5	8.4	10.0
Industrial	4.4	4.4	4.5	4.7	4.1	5.5	6.3	4.2	5.8	6.9
Transportation	5.3	5.0	5.1	5.1	4.6	5.8	5.9	4.5	5.8	6.0
All Sectors Average	**6.6**	**6.4**	**6.5**	**6.7**	**6.1**	**7.7**	**8.6**	**6.2**	**7.9**	**9.3**
Prices by Service Category[9] (1999 cents/kwh)										
Generation	4.1	3.8	3.9	4.2	3.5	4.9	5.8	3.6	5.2	6.6
Transmission	0.6	0.6	0.6	0.6	0.7	0.8	0.8	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.0	2.0	2.1
Emissions (million short tons)										
Sulfur Dioxide	13.71	10.38	8.55	8.55	9.70	2.75	3.06	8.95	2.38	2.64
Nitrogen Oxide	5.45	4.30	3.06	3.07	4.34	1.27	1.29	4.49	1.18	1.31

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Electric Generators[2]										
Capability										
Coal Steam	305.1	303.9	302.8	302.8	318.6	268.2	267.6	318.5	233.5	234.0
Other Fossil Steam[3]	137.4	127.8	120.0	119.9	119.2	104.0	104.4	116.9	86.6	86.7
Combined Cycle	21.0	53.2	85.6	83.3	107.8	256.4	224.6	202.2	319.5	255.7
Combustion Turbine/Diesel	74.3	123.1	115.1	116.4	147.2	117.7	118.7	199.5	124.5	122.2
Nuclear Power	97.4	97.5	97.5	97.5	94.8	97.5	97.5	76.3	89.4	91.5
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	94.8	99.5	100.0	98.0	111.8	111.5	99.5	142.2	149.2
Distributed Generation[5]	0.0	0.7	0.5	0.7	2.5	1.3	1.4	11.5	2.9	2.1
Total	**743.4**	**820.4**	**840.4**	**840.1**	**907.8**	**976.5**	**945.3**	**1044.2**	**1018.4**	**961.3**
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	0.0	0.0	18.9	0.0	0.0	20.5	0.0	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	19.4	51.8	49.6	74.2	222.8	190.9	168.6	285.8	222.0
Combustion Turbine/Diesel	0.0	38.9	31.9	33.7	64.7	36.0	37.1	117.2	43.1	41.0
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	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.4	5.2	5.7	2.0	15.8	15.5	2.0	44.8	51.7
Distributed Generation[5]	0.0	0.7	0.5	0.7	2.5	1.3	1.4	11.5	2.9	2.1
Total	**0.0**	**60.6**	**89.4**	**89.6**	**162.2**	**275.8**	**244.9**	**319.8**	**376.6**	**316.9**
Cumulative Total Additions	**0.0**	**92.6**	**121.4**	**121.6**	**195.9**	**309.5**	**278.6**	**355.1**	**411.9**	**352.2**
Cumulative Retirements[7]										
Coal Steam	0.0	2.3	2.3	2.3	5.4	36.9	37.6	7.2	71.6	71.1
Other Fossil Steam[3]	0.0	9.9	17.7	17.8	18.4	33.7	33.2	20.7	50.9	50.8
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	4.4	5.3	5.8	6.0	6.7	6.9	6.3	7.0	7.2
Nuclear Power	0.0	0.0	0.0	0.0	2.6	0.0	0.0	21.2	8.1	6.0
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	0.0	16.7	25.4	26.0	32.8	77.6	77.9	55.6	137.9	135.4
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.6	7.0	7.4	8.6	7.0	7.3
Petroleum	2.7	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0
Natural Gas	34.6	39.9	40.3	40.9	43.3	47.4	51.1	51.4	73.6	90.8
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.1	1.2	1.2
Renewable Sources[4]	5.4	5.9	5.9	5.9	6.8	6.8	6.8	8.2	8.3	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**52.4**	**59.2**	**59.7**	**60.2**	**63.3**	**65.9**	**70.0**	**73.2**	**94.0**	**111.4**
Cumulative Additions[6]	**0.0**	**6.8**	**7.2**	**7.8**	**10.9**	**13.5**	**17.6**	**20.7**	**41.6**	**59.0**

Table K5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
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	1.4
Cumulative Additions	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.4

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
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	152.0	202.3	149.8	151.2	155.5	98.1	89.9	147.9	110.3	113.1
Gross Domestic Trade	**334.2**	**327.6**	**275.1**	**276.4**	**258.4**	**201.1**	**192.8**	**147.9**	**110.3**	**113.1**
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)	4413.9	6468.6	5686.5	5458.3	4510.4	4761.0	4622.5	4605.1	6245.6	7140.3
Gross Domestic Sales (million 1999 dollars)	**13002.0**	**12374.4**	**11592.3**	**11364.1**	**9361.6**	**9612.2**	**9473.7**	**4605.1**	**6245.6**	**7140.3**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	10.7	5.8	19.1	19.1	0.0	12.1	12.1
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**	**65.0**	**65.0**	**30.6**	**42.7**	**42.7**
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.

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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Production										
Dry Gas Production[1]	18.67	21.40	21.06	20.82	23.43	25.95	25.89	29.47	30.45	26.93
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**	**4.69**	**4.73**	**4.69**	**5.00**	**6.83**	**5.57**	**5.82**	**8.30**	**6.40**
Canada	3.29	4.48	4.52	4.48	4.72	5.19	5.24	5.43	5.88	5.73
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	0.32	-0.25	-0.40	0.36	-0.40
Liquefied Natural Gas	0.10	0.39	0.39	0.39	0.53	1.32	0.58	0.79	2.07	1.07
Total Supply	**22.15**	**26.20**	**25.91**	**25.63**	**28.49**	**32.84**	**31.52**	**35.35**	**38.80**	**33.39**
Consumption by Sector										
Residential	4.75	5.42	5.44	5.45	5.46	5.27	5.28	6.07	5.86	5.74
Commercial	3.06	3.88	3.90	3.90	4.06	3.89	3.90	4.32	4.34	4.42
Industrial[3]	8.31	8.81	8.79	8.81	9.48	9.16	9.20	10.53	10.40	10.10
Electric Generators[4]	3.64	5.43	5.15	4.86	6.81	11.63	10.25	11.19	14.84	10.04
Lease and Plant Fuel[5]	1.23	1.38	1.36	1.35	1.50	1.62	1.62	1.87	1.91	1.74
Pipeline Fuel	0.64	0.81	0.80	0.79	0.88	0.98	0.97	1.07	1.12	1.03
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.14	0.14
Total	**21.65**	**25.79**	**25.50**	**25.21**	**28.29**	**32.64**	**31.32**	**35.20**	**38.63**	**33.21**
Discrepancy[7]	**0.50**	**0.42**	**0.41**	**0.41**	**0.20**	**0.21**	**0.20**	**0.14**	**0.18**	**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.
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, M2P7B08C.D060901A, M2P7B08L.D060901A. Other 1999 consumption: EIA, *Short-Term Energy Outlook, September 2000,* http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/sep00.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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K8. 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	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.96	2.84	2.81	2.87	3.96	4.08	3.22	4.15	5.05
Average Import Price	2.29	2.95	2.95	2.95	2.64	3.15	3.05	2.72	3.25	3.26
Average[2]	**2.11**	**2.96**	**2.86**	**2.84**	**2.82**	**3.79**	**3.89**	**3.13**	**3.95**	**4.68**
Delivered Prices										
Residential	6.69	7.31	7.21	7.18	6.91	7.89	7.98	6.83	7.69	8.46
Commercial	5.49	5.70	5.61	5.58	5.82	6.79	6.88	5.93	6.77	7.51
Industrial[3]	2.87	3.74	3.64	3.61	3.59	4.66	4.74	3.95	4.86	5.64
Electric Generators[4]	2.63	3.50	3.53	3.48	3.32	4.80	4.83	3.78	4.99	5.58
Transportation[5]	7.21	7.48	7.38	7.35	7.40	8.41	8.50	7.61	8.40	8.99
Average[6]	**4.15**	**4.84**	**4.79**	**4.77**	**4.59**	**5.58**	**5.68**	**4.72**	**5.64**	**6.45**
Transmission & Distribution Margins[7]										
Residential	4.58	4.35	4.35	4.35	4.08	4.10	4.10	3.70	3.74	3.78
Commercial	3.37	2.74	2.75	2.74	2.99	3.00	2.99	2.81	2.82	2.83
Industrial[3]	0.76	0.78	0.78	0.77	0.77	0.87	0.85	0.82	0.91	0.96
Electric Generators[4]	0.52	0.54	0.66	0.64	0.49	1.01	0.94	0.65	1.04	0.90
Transportation[5]	5.10	4.51	4.52	4.51	4.58	4.62	4.61	4.48	4.45	4.31
Average[6]	**2.04**	**1.88**	**1.93**	**1.93**	**1.76**	**1.79**	**1.79**	**1.59**	**1.69**	**1.77**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.77	23.57	23.65	23.68	22.30	21.64	21.62	22.48	21.91	21.73
Commercial	10.32	10.63	10.70	10.71	12.16	11.67	11.68	12.12	12.22	12.52
Industrial[3]	6.28	6.86	6.85	6.82	7.26	7.92	7.82	8.65	9.44	9.72
Electric Generators[4]	1.88	2.94	3.42	3.10	3.36	11.72	9.61	7.24	15.38	9.06
Transportation[5]	0.08	0.24	0.24	0.24	0.41	0.40	0.40	0.68	0.63	0.60
Total	**40.32**	**44.25**	**44.86**	**44.55**	**45.49**	**53.36**	**51.13**	**51.18**	**59.58**	**53.64**

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**21.43**	**21.44**	**21.85**	**20.73**	**20.91**	**20.98**	**21.47**	**21.41**	**21.39**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.66**	**5.67**	**5.58**	**5.32**	**5.30**	**5.09**	**5.25**	**5.47**	**5.05**
Lower 48 Onshore	3.27	2.81	2.81	2.81	2.52	2.53	2.50	2.75	2.86	2.70
Conventional	2.59	2.18	2.17	2.17	1.81	1.85	1.80	1.98	2.13	2.00
Enhanced Oil Recovery	0.68	0.63	0.63	0.63	0.70	0.68	0.70	0.76	0.73	0.70
Lower 48 Offshore	1.56	2.06	2.07	2.00	2.16	2.13	1.98	1.87	1.97	1.76
Alaska	1.05	0.79	0.79	0.77	0.65	0.65	0.61	0.64	0.64	0.60
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.75**	**15.76**	**15.50**	**14.55**	**14.61**	**14.10**	**14.11**	**14.56**	**13.58**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.96**	**2.84**	**2.81**	**2.87**	**3.96**	**4.08**	**3.22**	**4.15**	**5.05**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**21.40**	**21.06**	**20.82**	**23.43**	**25.95**	**25.89**	**29.47**	**30.45**	**26.93**
Lower 48 Onshore	12.83	14.46	14.10	14.09	16.71	18.40	18.05	21.31	22.21	18.94
Associated-Dissolved[4]	1.80	1.51	1.51	1.52	1.32	1.34	1.32	1.39	1.48	1.43
Non-Associated	11.03	12.95	12.59	12.57	15.39	17.07	16.73	19.91	20.72	17.51
Conventional	6.64	7.67	7.51	7.41	7.93	8.92	9.00	11.14	10.79	9.22
Unconventional	4.39	5.27	5.08	5.16	7.45	8.15	7.72	8.78	9.93	8.29
Lower 48 Offshore	5.43	6.47	6.50	6.27	6.22	7.05	7.35	7.59	7.67	7.43
Associated-Dissolved[4]	0.93	1.06	1.06	1.04	1.09	1.09	1.06	1.04	1.06	1.01
Non-Associated	4.50	5.41	5.43	5.22	5.13	5.96	6.29	6.56	6.62	6.42
Alaska	0.42	0.47	0.47	0.46	0.50	0.50	0.50	0.57	0.56	0.56
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**167.88**	**169.46**	**168.59**	**185.55**	**184.15**	**167.64**	**200.71**	**217.28**	**184.23**
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**	**28.87**	**28.13**	**27.80**	**29.86**	**35.72**	**34.43**	**39.36**	**50.58**	**42.16**

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Production[1]										
Appalachia	433	426	409	420	421	232	250	396	218	239
Interior	185	182	174	177	180	112	117	161	96	113
West	486	624	578	571	694	297	314	783	257	309
East of the Mississippi	559	561	538	551	557	337	360	524	307	345
West of the Mississippi	544	672	623	616	738	304	321	817	264	316
Total	**1103**	**1233**	**1161**	**1167**	**1295**	**641**	**681**	**1340**	**571**	**661**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	57	57	56	63	60
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-48**	**-48**	**-36**	**-54**	**-51**
Total Supply[2]	**1054**	**1189**	**1113**	**1119**	**1254**	**593**	**633**	**1304**	**517**	**609**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	82	82	82	83	80	82	86	84	87
Coke Plants	28	25	25	25	23	23	23	19	19	19
Electric Generators[4]	921	1077	1002	1007	1145	485	521	1196	408	499
Total	**1032**	**1189**	**1114**	**1119**	**1256**	**593**	**631**	**1306**	**517**	**610**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-0**	**-2**	**1**	**2**	**-2**	**0**	**-1**
Average Minemouth Price										
(1999 dollars per short ton)	17.17	15.05	14.77	14.97	14.08	14.39	14.67	12.87	13.37	13.95
(1999 dollars per million Btu)	0.82	0.73	0.71	0.72	0.69	0.66	0.68	0.64	0.62	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.39	29.67	29.37	29.48	28.61	25.37	25.78	26.50	23.10	23.85
Coke Plants	44.28	42.39	42.51	42.42	41.36	40.85	41.17	38.52	38.47	38.90
Electric Generators										
(1999 dollars per short ton)	24.73	22.90	21.64	21.77	21.28	19.22	19.67	19.41	17.58	18.66
(1999 dollars per million Btu)	1.21	1.14	1.07	1.07	1.06	0.92	0.94	0.98	0.84	0.89
Average	**25.77**	**23.78**	**22.68**	**22.80**	**22.13**	**20.89**	**21.25**	**20.15**	**19.25**	**20.04**
Exports[7]	37.44	36.39	36.36	36.32	35.66	32.99	33.43	33.09	30.55	31.58

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A. **Projections:** EIA, AEO2001 National Energy Modeling System runs M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.77	79.26	79.60	80.43	79.38	80.90	80.90	79.38	81.11	81.13
Geothermal[2]	2.87	3.43	7.12	6.66	4.93	11.04	10.63	4.95	11.44	11.56
Municipal Solid Waste[3]	2.61	2.96	3.24	3.24	3.42	4.42	4.42	3.93	4.95	4.94
Wood and Other Biomass[4]	1.57	1.75	1.98	2.09	2.12	4.62	4.44	2.45	17.92	18.25
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	7.10	7.14	7.52	10.19	10.47	7.76	25.78	32.30
Total	**88.83**	**94.75**	**99.47**	**100.01**	**97.98**	**111.77**	**111.46**	**99.49**	**142.22**	**149.21**
Generation (billion kilowatthours)										
Conventional Hydropower	309.55	301.20	302.25	305.12	301.13	306.22	306.18	300.07	305.63	305.65
Geothermal[2]	13.21	18.34	48.83	44.99	30.94	81.21	77.85	31.16	84.63	85.58
Municipal Solid Waste[3]	18.12	20.68	22.94	22.94	23.88	31.67	31.67	27.76	35.70	35.68
Wood and Other Biomass[4]	9.02	14.94	32.83	28.22	21.30	68.63	70.13	19.78	154.00	163.41
Dedicated Plants	7.73	9.16	10.69	11.44	11.36	28.12	26.92	13.82	117.15	119.35
Cofiring	1.29	5.78	22.15	16.78	9.94	40.51	43.20	5.95	36.84	44.06
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	16.80	16.93	18.16	25.66	26.36	18.83	74.22	94.21
Total	**355.43**	**372.61**	**424.81**	**419.35**	**397.03**	**515.01**	**513.79**	**400.32**	**656.90**	**687.25**
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	5.17	5.19	5.19	6.06	6.07	6.06	7.54	7.57	7.54
Total	**5.35**	**5.87**	**5.89**	**5.89**	**6.76**	**6.77**	**6.76**	**8.24**	**8.27**	**8.24**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.04	4.05
Biomass	27.08	29.92	30.05	30.02	35.01	35.02	34.90	43.52	43.62	43.40
Total	**31.12**	**33.97**	**34.09**	**34.06**	**39.05**	**39.06**	**38.94**	**47.57**	**47.66**	**47.44**
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	0.38
Total	**1.00**	**1.09**	**1.09**	**1.09**	**1.34**	**1.34**	**1.34**	**1.34**	**1.34**	**1.37**
Generation (billion kilowatthours)										
Conventional Hydropower[7]	4.57	4.44	4.44	4.44	4.43	4.43	4.43	4.41	4.41	4.42
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	0.82
Total	**4.59**	**4.64**	**4.64**	**4.64**	**5.18**	**5.18**	**5.18**	**5.17**	**5.17**	**5.24**

[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.

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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.42**	**0.44**	**0.42**	**0.42**
Wood	0.41	0.42	0.42	0.42	0.42	0.42	0.42	0.44	0.42	0.42
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**	**2.42**	**2.41**	**2.41**	**2.64**	**2.63**	**2.63**	**3.08**	**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	2.23	2.22	2.22	2.46	2.44	2.44	2.90	2.89	2.89
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.22**	**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**	**4.19**	**5.33**	**5.19**	**4.73**	**7.00**	**6.93**	**4.78**	**8.44**	**8.70**
Conventional Hydroelectric	3.19	3.10	3.11	3.14	3.10	3.15	3.15	3.08	3.14	3.14
Geothermal	0.28	0.44	1.36	1.24	0.85	2.42	2.33	0.85	2.54	2.60
Municipal Solid Waste[6]	0.25	0.28	0.31	0.31	0.32	0.43	0.43	0.38	0.49	0.49
Biomass	0.12	0.18	0.36	0.31	0.26	0.71	0.73	0.25	1.48	1.57
Dedicated Plants	0.10	0.11	0.12	0.13	0.14	0.29	0.28	0.17	1.12	1.15
Cofiring	0.02	0.07	0.24	0.19	0.12	0.42	0.45	0.07	0.35	0.42
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	0.26	0.27	0.19	0.76	0.86
Total Marketed Renewable Energy	**6.64**	**7.31**	**8.44**	**8.30**	**8.10**	**10.34**	**10.27**	**8.62**	**12.27**	**12.51**
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	0.20	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**	**0.22**	**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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Residential										
Petroleum	26.0	26.5	26.5	26.5	24.5	24.6	24.6	23.2	23.7	23.5
Natural Gas	69.5	80.2	80.5	80.6	80.8	78.0	78.1	89.8	86.7	84.9
Coal	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	193.4	227.1	210.9	210.7	242.6	150.2	150.0	275.6	158.4	161.7
Total	**290.1**	**335.0**	**319.1**	**319.0**	**349.2**	**254.2**	**254.0**	**389.8**	**270.0**	**271.3**
Commercial										
Petroleum	13.7	11.8	11.8	11.8	12.0	12.4	12.3	12.1	13.6	14.0
Natural Gas	45.4	57.4	57.6	57.7	60.1	57.5	57.7	63.9	64.1	65.4
Coal	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
Electricity	181.3	218.4	203.5	203.4	240.4	150.1	150.4	267.1	151.4	153.7
Total	**242.1**	**289.4**	**274.8**	**274.7**	**314.3**	**221.9**	**222.3**	**345.0**	**231.1**	**235.0**
Industrial[1]										
Petroleum	104.2	99.2	98.6	98.5	105.3	108.9	109.5	113.6	119.7	127.3
Natural Gas[2]	141.6	148.4	147.9	148.0	159.8	156.9	157.6	180.3	179.4	172.3
Coal	55.9	65.8	65.5	65.6	65.6	63.3	64.5	65.8	64.6	66.3
Electricity	178.8	193.6	179.1	179.4	204.1	127.7	128.2	226.4	125.1	125.5
Total	**480.4**	**507.0**	**491.2**	**491.5**	**534.8**	**456.8**	**459.8**	**586.1**	**488.8**	**491.5**
Transportation										
Petroleum[3]	485.8	556.3	554.6	554.2	607.2	602.6	602.3	704.2	700.4	699.7
Natural Gas[4]	9.5	12.8	12.7	12.5	14.4	15.8	15.7	18.1	18.7	17.3
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	4.1	4.1	5.8	3.8	3.9	7.9	4.8	5.2
Total[3]	**498.2**	**573.6**	**571.4**	**570.9**	**627.5**	**622.2**	**621.9**	**730.2**	**724.0**	**722.3**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	693.8	691.5	691.0	749.0	748.5	748.8	853.1	857.4	864.6
Natural Gas	266.0	298.8	298.6	298.8	315.1	308.2	309.0	352.0	349.0	339.9
Coal	58.8	68.8	68.5	68.5	68.8	66.5	67.7	69.0	67.8	69.5
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	643.6	597.7	597.7	692.8	431.8	432.5	777.0	439.7	446.0
Total[3]	**1510.**	**1705.0**	**1656.4**	**1656.1**	**1825.7**	**1555.1**	**1558.0**	**2051.2**	**1714.0**	**1720.0**
Electric Generators[6]										
Petroleum	20.0	9.4	3.9	3.7	5.8	2.0	3.1	5.2	3.7	31.9
Natural Gas	45.8	79.6	75.6	71.3	100.0	170.6	150.5	164.1	217.8	147.4
Coal	490.5	554.6	518.2	522.8	587.0	259.1	278.9	607.7	218.1	266.8
Total	**556.3**	**643.6**	**597.7**	**597.7**	**692.8**	**431.8**	**432.5**	**777.0**	**439.7**	**446.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	703.1	695.5	694.7	754.8	750.5	751.9	858.3	861.1	896.5
Natural Gas	311.8	378.4	374.2	370.0	415.0	478.8	459.5	516.2	566.8	487.2
Coal	549.3	623.3	586.7	591.3	655.8	325.6	346.5	676.7	286.0	336.2
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.**	**1705.0**	**1656.4**	**1656.1**	**1825.7**	**1555.1**	**1558.0**	**2051.2**	**1714.0**	**1720.0**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.8**	**5.7**	**6.1**	**5.2**	**5.2**	**6.3**	**5.3**	**5.3**

[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.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Table K14. Emissions, Allowance Costs, and Retrofits: Electric Generators, Excluding Cogenerators

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price	Reference	Integrated Cost of Service	Integrated High Gas Price
Emissions										
Nitrogen Oxide (million tons)	5.45	4.30	3.06	3.07	4.34	1.27	1.29	4.49	1.18	1.31
Sulfur Dioxide (million tons)	13.71	10.38	8.55	8.55	9.70	2.75	3.06	8.95	2.38	2.64
Mercury (tons)	43.60	45.24	40.67	40.00	45.60	5.00	5.00	45.07	5.00	5.00
Carbon Dioxide (million metric tons carbon equivalent)	556.31	643.58	597.68	597.69	692.78	431.81	432.45	776.99	439.68	446.03
Allowance Prices										
Nitrogen Oxide (1999 dollars per ton)	0	4352	1346	1423	4391	0	0	5037	0	0
Sulfur Dioxide (1999 dollars per ton)	0	190	178	177	187	0	0	241	0	2
Mercury (million 1999 dollars per ton)	0	0	0	0	0	308	305	0	244	344
Carbon Dioxide (1999 dollars per ton carbon equivalent)	0	0	36	27	0	117	125	0	162	169
Retrofits (gigawatts)										
Scrubber [1]	0.0	6.5	10.2	15.2	7.1	21.5	27.0	14.8	21.5	27.0
Combustion	0.0	39.9	50.3	52.1	42.1	54.0	56.9	46.1	55.9	58.2
SCR Post-combustion	0.0	92.8	53.4	61.5	92.9	83.2	94.8	93.0	83.2	94.8
SNCR Post-combustion	0.0	25.2	33.5	18.2	26.3	84.0	83.0	43.4	84.1	83.1
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472	594	581	577	642	284	308	721	257	303
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432	454	400	409	464	234	243	440	203	234
High Sulfur (> 1.67 lbs. S/mmBtu)	199	185	180	181	188	123	130	179	111	123

[1]Represents scrubbers added by the model. Planned scrubbers added by electricity generators are not shown here.
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 M2BASE.D060801A, M2P7B08C.D060901A, M2P7B08L.D060901A.

Appendix L

Pollution Control Costs

Appendix L

Pollution Control Costs

The costs for adding flue gas desulfurization equipment (scrubbers) are specific to each plant in the model. The costs generally vary with plant size (it is less expensive for larger plants) and an assessment of the difficulty of retrofitting the specific plant. On average, scrubber retrofits cost $195 per kilowatt (in 1997 dollars).

The cost assumptions for NO_x controls are from the U.S. Environmental Protection Agency (EPA) report, *Analyzing Electric Power Generation Under the CAAA*.[83] Table K1, reproduced from the EPA report, provides the cost and performance parameters assumed for post-combustion NO_x controls for coal-fired power plants.

Table L1. Post-Combustion NO_x Controls for Coal-Fired Power Plants

Post-Combustion Control Technology	Capital (1997 Dollars per Kilowatt)	Fixed O&M (1997 Dollars per Kilowatt per Year)	Variable O&M (1997 Mills per Kilowatthour)	Percent Gas Use	Percent Removal
SCR (Low NO_x Rate)	69.70	6.12	0.24	—	70
SCR (High NO_x Rate)	71.80	6.38	0.40	—	80
SNCR (Low NO_x Rate).	16.60	0.24	0.82	—	40
SNCR (High NO_x Rate, Cyclone)	9.60	0.14	1.27	—	35
SNCR (High NO_x Rate, Other)	19.00	0.29	0.88	—	35

Assumptions: Low NO_x Rate <0.5 lb/MMBtu; High NO_x Rate ≥0.5 lb/MMBtu. Scaling factor for coal SCR = $(200/MW)^{0.35}$, economies of scale assumed up to 500 MW. Scaling factor for low-NO_x coal SNCR = $(200/MW)^{0.577}$, economies of scale assumed up to 500 MW. Scaling factor for High NO_x Coal SNCR, cyclone = $(100/MW)^{0.577}$; variable O&M costs = 1.27 for ≤300 MW, 1.27 – ((MW – 300)/100) x 0.015 for >300 MW. Scaling factor for high-NO_x coal SNCR, Other = $(100/MW)^{0.681}$; variable O&M costs = 0.88 for ≤480 MW, 0.89 for >480 MW. Gas Reburn includes $5.2/kW charge for pipeline.

Sources: All estimates taken from the Bechtel report, except gas reburn, which is based on the Acurex Report.

[83] U.S. Environmental Protection Agency, *Analyzing Electric Power Generation Under the CAAA* (Washington, DC, March 1998).