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Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide

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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, and 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. 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
Natural Gas		
Joe Benneche	202 / 586-6132	jbennech@eia.doe.gov
Jim Lockhart	202 / 586-2854	james.lockhart@eia.doe.gov
Coal		
Mike Mellish	202 / 586-2136	mmellish@eia.doe.gov
Edward Flynn	202 / 586-5748	eflynn@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), nitrogen oxides (NO_x), carbon dioxide (CO_2) and mercury (Hg). At present, neither the future reduction requirements nor the complete timetable is known for any of these airborne emissions, and compliance planning is difficult. Power plant operators are wary of making investments that could prove uneconomical if and when new regulations are enacted. 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 may not be optimal if Hg and / or CO_2 emissions must also be reduced later.

Recently, some have proposed plans requiring coordinated multi-emission reductions. 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 to examine the costs of such multi-emission reduction strategies (see Appendix J 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 (see Chapters 2 and 5 for descriptions of the cases) incorporating NO_x, SO_2, CO_2, and Hg emission reduction requirements and renewable portfolio standard (RPS) requirements.

In response to the Subcommittee's request, EIA has prepared this report as the first of two volumes. This report addresses NO_x, SO_2, and CO_2 emission reductions. The second volume will extend the analysis to Hg emission reductions and 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. 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 examines the impacts of alternative assumptions about the possible outcomes of ongoing litigation related to new source reviews, and Chapter 6 compares the results of this analysis with those of other analyses.

Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review earlier versions of this analysis and provide comment. The reviewers provided comments on two draft versions of the report and discussed their comments in a joint meeting. 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 in preparing the report is gratefully acknowledged:

Dallas Burtraw
Resources for the Future

Howard Gruenspecht
Resources for the Future

David Hawkins
Natural Resources Defense Council

Gordon Hester
Electric Power Research Institute

Hill Huntington
Energy Modeling Forum

Henry Lee
Harvard University

Karen Palmer
Resources for the Future.

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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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Background

Over the next decade, power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2) and mercury (Hg). At present, neither the future reduction requirements nor the complete timetable is known for any of these airborne emissions, and compliance planning is difficult. In response to the Clean Air Act Amendments of 1990 (CAAA90), operators are now in the process of making reductions in power plant emissions of SO_2 and NO_x. Phase II of the CAAA90 SO_2 reduction program—lowering allowable SO_2 emissions to an annual cap of 8.95 million tons—became effective on January 1, 2000, and more stringent NO_x emissions standards setting new emission limits for boilers also took effect in 2000.

States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, they may have to be further 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 would take effect in 2004. The fine particulate issue is still being studied, but reduced SO_2 emissions from power plants could be required as early as 2007 to address it. In addition, on December 15, 2000, the EPA decided that Hg emissions need to be reduced; and if the United States ratifies the Kyoto Protocol or a similar international greenhouse gas mitigation treaty, energy-related CO_2 emissions would also have to be reduced.

With changing standards on different timetables, comprehensive compliance planning is difficult. It can take several years to design, license, and construct new 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 far into the future to evaluate the economics of new investment decisions. Changing emission standards with different timetables add 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 may not be optimal if Hg and CO_2 emissions must also be reduced at a later date. Further complicating planning, some investments reduce multiple emissions simultaneously, such as SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners are wary of making investments that may prove unwise a few years hence.

Recently, plans have been proposed requiring coordinated multi-emission reductions. Several bills that have been introduced in Congress contain such provisions: 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. Each of these bills 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, or combinations of the three—but all call for significant emission reductions.

This report provides analysis of the potential impacts of efforts to reduce NO_x, SO_2, and CO_2 emissions from power plants. It examines the potential costs, to the energy sector and to consumers, of meeting the specified emission caps. It does not address the potential benefits of reduced emissions, such as might be associated with reduced health care costs, because EIA does not have expertise in this area. Readers should refer to the EPA and others for analysis of the potential benefits of emissions reductions. The bibliography for this report includes several studies that address the benefits of reducing emissions.[1]

The results in this report should not be interpreted as providing estimates of the electricity price changes and other impacts that would result from the enactment of the legislative proposals discussed previously. This analysis assumes a cap-and-trade mechanism, patterned after the system for SO_2 allowances implemented in CAAA90, for modeling all emission reductions in all

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[1] Reports by Burtraw, Chestnut, and the EPA cited in the bibliography of this report include discussions of health benefits.

scenarios. The legislative proposals cited above include a variety of mechanisms to achieve emission reductions. Because the policy mechanisms used to implement emission reduction programs can affect compliance decisions and the resulting electricity prices, analysis of the specific policies called for in each proposal would be required to address their impacts.

The analysis 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. In its request the Subcommittee asked the Energy Information Administration (EIA) to analyze the potential costs of various multi-emission reduction 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 and renewable portfolio standard (RPS) requirements. The Subcommittee specified that the NO_x, SO_2, and CO_2 analysis should be done first if the Hg analysis could not be completed until a later date. This report examines NO_x, SO_2, and CO_2 emission limits. It does not address the potential impact of requirements to reduce power plant Hg emissions. A second volume, to be published in early 2001, will examine Hg emission limits and RPS requirements.

Cases Analyzed

A reference case and 10 basic analysis cases are examined in this report (Table ES1). Each case differs in terms of the specific emission caps imposed on the power sector and when they are imposed. Two NO_x cap cases look at the impacts of reducing power sector NO_x emissions to 75 percent below the level emitted in 1997. In the NO_x 2005 case, the cap on NO_x emissions is assumed to take effect in 2005; in the NO_x 2008 case, the cap is assumed to take effect in 2008. Two SO_2 cap cases assume similar reductions in power sector SO_2 emissions. Two CO_2 cap cases examine the impacts of reducing power sector CO_2 emissions to 1990 levels by 2005 or 2008 and, in both cases, further reducing them to 7 percent below that level, on average, between 2008 and 2012. Finally, four integrated cases examine the impacts of combining the various assumptions from the other cases for power sector emission caps on NO_x, SO_2, and CO_2. In each of the cases it is assumed that the emission reduction programs would operate as “cap and trade” programs, with power plant operators required to reduce their emissions or purchase sufficient allowances to cover them.

Four additional cases with alternative assumptions about the potential impacts of ongoing New Source Review (NSR) litigation against the owners of coal-fired power plants are also analyzed. The Subcommittee requested these cases in a letter dated September 25, 2000 (see Appendix J). The first case, referred to as the NSR 32 case, uses all of EIA’s reference case assumptions combined with the assumption that the owners of each of the 32 coal plants being sued for violating CAAA90 will be required to add emission control equipment to reduce NO_x and SO_2 by 2005 in order to continue operating them. The second case, referred to as the NSR All case, again uses all of EIA’s reference case assumptions but assumes that all coal-fired plants in addition to the 32 being sued will be required to have control equipment added to reduce NO_x and SO_2 emissions by 2010. The final two cases, referred to as the integrated NSR 32 and integrated NSR All cases, combine the assumptions of the NSR 32 and NSR All cases with those of the integrated 1990-7% 2005 case. In both of the NSR All cases it is assumed that the 32 plants currently being sued must still make their compliance decisions by 2005.

In addition to the cases requested by the Subcommittee, this report includes two cases that assume less stringent emission caps for SO_2 and CO_2 and an integrated case that combines the less stringent targets (Table ES2). These cases were analyzed to examine the sensitivity of the results to the emission targets chosen. The emission cap in the SO_2 sensitivity case was set halfway between the estimated emissions for 2000 and the caps requested by the Subcommittee—roughly a 50-percent reduction from 1997 levels, rather than the 75-percent reduction specified by the Subcommittee. For CO_2 a similar approach was used. The CO_2 cap in 2005 in the CO_2 sensitivity case was set to halfway between the estimated emissions in 2000 and the 1990 level. The cap was then lowered further over the 2008 to 2012 time period, to halfway between the estimated 2000 emissions and 7 percent below the 1990 level. Using this approach, the CO_2 cap in 2005 in the CO_2 sensitivity case was assumed to be 12 percent above 1990 levels, before declining to 7 percent above 1990 levels over the 2008 to 2012 time period.

Analysis Approach

In this analysis, it is assumed that the programs set up to reduce NO_x, SO_2, and CO_2 emissions from power plants will operate like the existing SO_2 program established in Title IV of CAAA90. Marketable emission allowances or permits are assumed to be allocated to power plant operators at no cost (and therefore no money would be collected by the government). No assumption is made about the specific allocation methodology to be used, other than that it is a fixed allocation (does not change from year to year) and the total amount allocated equals the national emission targets for NO_x, SO_2, and CO_2. Holders of allowances are assumed to be free to use them to cover emissions from their own power plants or sell them to others who need them.

Table ES1. Analysis Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
NO_x Cap Cases						
NO_x 2005	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2005	None
NO_x 2008	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2008	None
SO_2 Cap Cases						
SO_2 2005	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2005	None
SO_2 2008	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2008	None
CO_2 Cap Cases						
CO_2 1990-7% 2005	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2005; 7% below 1990 level in 2008-2012	None
CO_2 1990-7% 2008	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2008; 7% below 1990 level in 2008-2012	None
Integrated Cases						
Integrated 2005	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2005	None
Integrated 1990-7% 2005	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; CO_2 1990 level by 2005; 7% below 1990 level in 2008-2012	None
Integrated 2008	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2008	None
Integrated 1990-7% 2008	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012	None

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 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target of 7 percent below 1990 levels is between 2008 and 2012. The cap is then held constant at that level through 2020. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: See requesting letters in Appendix J.

The analysis presented in this report should be seen as an examination of the steps that power suppliers and consumers might take to meet the emission caps specified by the Subcommittee. The specific design of the cases—timing, emission cap levels, policy instruments used, etc.—are important and should be kept in mind when the results are reviewed. For example, it is assumed that the market participants—power suppliers, consumers, and coal, gas, and renewable fuel suppliers—would become aware of the impending emission caps before their target dates and begin to take action to meet the future targets. If the timing of market response were different, the results would change. In previous EIA studies 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.[2]

In addition, 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 indicating the consequences of specific legislative proposals. All the proposals include

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[2] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998); and *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999).

Table ES2. Assumed Emission Caps for Electricity Generators in Sensitivity Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
SO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	None	None	Start 2002; meet target by 2005	None
CO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% above 1990 level	None	Start 2002; reach 10% above 1990 CO_2 level in 2005 and 7% above 1990 level in 2008-2012	None
Integrated Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	7% above 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; for CO_2, reach 10% above 1990 level in 2005 and 7% above 1990 level in 2008-2012	None

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 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target 7 percent above 1990 levels is between 2008 and 2012. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: Office of Integrated Analysis and Forecasting.

provisions other than the emission caps studied in this analysis. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be required because of ongoing environmental programs whose requirements currently are not specified but for which legislation has been promulgated.

Key Findings

- When emissions caps are examined individually, power companies are projected to invest primarily in emission control equipment to comply with the NO_x and SO_2 caps; however, to comply with the CO_2 cap they are expected to shift dramatically away from coal to natural gas and, to a lesser extent, renewables.
- The stringency of the emission targets influences the projected impact on electricity and natural gas prices.
- The impacts of meeting the NO_x and SO_2 caps are not projected to have a large effect on electricity prices—generally 1 percent or so above the prices expected in the reference case.
- The projected price impacts of meeting the CO_2 cap are much larger than those of meeting the NO_x and SO_2 caps.
- The CO_2 allowance prices (expressed in dollars per metric ton carbon equivalent) projected in this analysis are generally lower than those projected in studies of efforts to meet the target from the Kyoto Protocol over the whole economy rather than just in the power sector.
- When emissions caps are examined together, actions taken to meet the CO_2 cap are expected to overshadow those taken to reduce NO_x and SO_2 emissions.
- Using an integrated approach—setting caps on power sector NO_x, SO_2, and CO_2 emissions at the same time—is projected to lead to lower total costs than addressing each emission one at a time.
- If existing coal plants are required to add emission control equipment, NO_x and SO_2 emissions would be dramatically reduced.
- There is considerable uncertainty about whether the changes projected in this analysis could be accomplished in the relatively short time periods assumed—particularly to meet 2005 emission targets.

Electricity Market Impacts

The emission caps specified by the Subcommittee are projected to affect all aspects of the electricity business, especially in cases that include a CO_2 cap. The caps affect capacity planning and retirement decisions, investments in emission control equipment, fuel choices for generation, and electricity prices. One issue that affects all the cases, especially those with 2005 compliance dates, is whether the time lines proposed are realistic. To meet the emission caps specified by the Subcommittee, electricity markets together with their associated fuel markets—coal, natural gas, renewables, and other fuels—would need to make rapid changes, which may be difficult to accomplish in a short time.

Compliance Decisions

In all the analysis cases, emission caps are projected to have significant impacts on coal-fired power plants, generally leading to lower utilization rates and earlier retirements of existing coal plants than those projected in the reference case, especially when CO_2 emission caps are assumed. In the NO_x and SO_2 cap cases only a small number of coal plants are expected to be retired; the vast majority are projected to control emissions and continue operating. The main compliance option in the NO_x and SO_2 cap cases is the addition of emission control equipment: selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment to reduce NO_x emissions, and flue gas desulfurization equipment (scrubbers) to reduce SO_2 (Table ES3). As expected, the projected need for emission control equipment is sensitive to the assumptions about the levels at which emissions would be capped.

The amount of emission control equipment projected to be needed in the NO_x and SO_2 cap cases, particularly those with 2005 compliance dates, could cause system operation problems 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. The amount of capacity to which emission control equipment is expected to be added in these cases could lead to a concentration of connection outages in the few years just before the emission caps take effect. This could lead to a large amount of capacity being temporarily unavailable, increasing the possibility of short-term imbalances of supply and demand caused by unexpected demand spikes and/or unplanned outages of other units. Such imbalances could have significant impacts on wholesale power prices, and in extreme cases they could lead to power outages.

Several recent studies have looked into whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the CAAA90 NO_x State implementation plan (SIP) call might lead to system operational and reliability problems. If a decision were made to pursue the stringent NO_x and SO_2 caps analyzed in this report without a CO_2 reduction requirement, additional analysis of this issue would be needed.

In the SO_2 sensitivity case, the less stringent emission caps examined are projected to lead to a lower amount of capacity to which emission control equipment would be added, as compared with the amounts expected in the more stringent cases. The need for new SO_2 emission control equipment is projected to be much lower in the integrated sensitivity case, because the CO_2 cap causes enough switching from coal to gas to allow the electricity generation sector to meet the assumed SO_2 caps without adding much additional emission control equipment.

Table ES3. Projected Additions of Power Plant Emission Controls, 1999-2020
(Gigawatts)

Analysis Case	Emission Control Technology		
	SNCR	SCR	FGD
Reference	39	90	15
NO_x Cap Cases			
NO_x 2005	59	252	14
NO_x 2008	60	243	15
SO_2 Cap Cases			
SO_2 2005	32	117	128
SO_2 2008	27	124	130
SO_2 Sensitivity	36	96	52
CO_2 Cap Cases			
CO_2 1990-7% 2005	16	42	0
CO_2 1990-7% 2008	22	54	0
CO_2 Sensitivity	26	54	0
Integrated Cases			
Integrated 2005	56	157	21
Integrated 1990-7% 2005	49	147	17
Integrated 2008	48	123	23
Integrated 1990-7% 2008	38	108	18
Integrated Sensitivity	26	60	8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction. FGD = flue gas desulfurization (scrubbers).

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

Compliance decisions made by power plant operators and their impacts on generation costs and consumer electricity prices could be very different if the various emissions caps were imposed together or one at a time on different schedules. Power plant owners would be expected to rely heavily on investments in emission control technologies to comply with the NO_x and SO_2 caps if they were introduced individually; but if the NO_x, SO_2, and CO_2 caps were combined, heavy investments in NO_x and SO_2 emission control equipment would not be expected to be part of the most economical compliance strategy. Rather, many of the coal-fired power plants where such equipment might have been added are projected to be retired if a stringent CO_2 cap is imposed. New natural gas plants, and to a lesser extent renewable plants, are projected to be built, and the lives of existing nuclear plants are projected to be extended.

The projected impacts on capacity expansion and retirement, fuel use (generation), and consumer electricity prices are similar in the CO_2 cap and integrated cases (Table ES4). When the three emission caps are assumed to be imposed in concert, efforts to comply with the CO_2 cap are projected to have the most significant effect, as can be seen by comparing the results for the CO_2 cap and integrated cases. When a CO_2 cap is assumed, large investments in NO_x and SO_2 emission control equipment, beyond the levels added in the reference case, are not expected to be needed, because the amount of coal-fired capacity projected to be retired in order to meet the hypothesized CO_2 cap is sufficient to meet the NO_x and SO_2 caps with little additional effort.

The move from coal to natural gas in the cases with CO_2 caps is expected to be significant (Figure ES1). Increased generation from natural gas is projected to be the primary compliance option in the cases that include CO_2 caps. By 2010, natural gas consumption for electricity generation is projected to be as high as 11.8 trillion cubic feet in the integrated cases, much higher than the 6.7 trillion cubic feet projected in the reference case. The share of generation coming from gas is projected to grow from 15 percent in 1999 to as high as 45 percent in 2010 and 56 percent in 2020 in the integrated cases. Again, electricity markets and the associated markets for coal, natural gas, renewables, and other fuels would need to make rapid changes, which could prove difficult to accomplish in a short time. In addition, increasing dependence on natural gas for electricity production could lead to greater volatility in electricity prices as they move with changes in gas prices.

Increased generation from renewables is expected to play a role in cases with CO_2 caps, but their contribution is much smaller than that of natural gas. In cases without a CO_2 cap, projected additions of renewable generating capacity are virtually unchanged from those projected in the reference case. When a CO_2 cap is assumed, carbon allowance fees are expected to increase the costs of building and operating generators using fossil fuels, making renewable technologies more economically attractive. Geothermal, biomass, and wind are expected to show the largest generation increases in the cases with CO_2 caps, and total generation from nonhydroelectric renewables is expected to provide as much as 8 percent of total electricity generation in 2020 in the integrated cases, substantially higher than the 3-percent share projected in the reference case.

Cost and Price Impacts

Power plant operators are expected to incur significant costs to comply with the emission caps in the NO_x and SO_2 cap cases, but they may not be able to pass all the costs on to consumers through higher electricity prices. In competitive markets, cost increases do not directly translate into price increases. Electricity generation prices in competitive markets are set by the operating costs of the marginal plant—the plant running with the highest cost during a given period. Cost increases that do not affect the operating costs of the marginal plant will not affect prices. In many cases, adding emission control equipment to a plant involves mainly capital expenditures and leads to little change in the plant’s operating costs. In addition, many of the plants to which the controls would be added are not price-setting plants. As a result, the addition of emission control equipment would not always lead directly to higher electricity prices, even though significant investments would be made.

In the NO_x cap cases, power plant operators are projected to spend more than $17 billion to add emission control equipment, much higher than the $10 billion expected in the reference case. These expenditures represent the capital costs of installing the equipment. The increased costs for power plant operators, if incurred in generation markets with cost-of-service regulation, would be passed on directly to consumers in electricity prices. In competitively priced markets, however, the higher costs would be passed on to consumers only if they increased the operating costs of the generating plants that set the market price for power. For example, if SCR equipment were added to reduce NO_x emissions from a coal plant that did not set the market price for power, the costs of installing and operating the equipment would not be passed on to consumers as long as the plant’s operating costs remained below the market price.

In the SO_2 cap cases, SO_2 allowance prices are projected to rise dramatically, reaching as high as $735 per ton in 2010 and $1,125 per ton in 2020, because of the need to add scrubbers to plants using relatively low-sulfur coal. In competitive electricity markets, however, the costs of adding and operating scrubbers would not affect the

Table ES4. Summary of Projections, 2010 and 2020

Analysis Case	Coal-Fired Electricity Generation (Billion Kilowatthours)	Natural-Gas-Fired Electricity Generation (Billion Kilowatthours)	Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Electricity Price (1999 Cents per Kilowatthour)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenues (Billion 1999 Dollars)
2010 Results							
Reference	2,284	1,123	NA	2.68	5.9	927	243
NO_x Cap Cases							
NO_x 2005	2,237	1,161	NA	2.68	5.9	933	245
NO_x 2008	2,237	1,164	NA	2.72	5.9	934	245
SO_2 Cap Cases							
SO_2 2005	2,198	1,195	NA	2.67	5.9	937	246
SO_2 2008	2,259	1,146	NA	2.63	5.9	929	243
SO_2 Sensitivity	2,237	1,169	NA	2.72	5.9	932	244
CO_2 Cap Cases							
CO_2 1990-7% 2005	1,113	1,859	143	4.36	8.3	1,126	319
CO_2 1990-7% 2008	1,055	1,922	139	4.13	8.2	1,126	318
CO_2 Sensitivity	1,454	1,609	102	3.48	7.6	1,070	297
Integrated Cases							
Integrated 2005	1,276	1,746	114	3.83	7.9	1,094	306
Integrated 1990-7% 2005	1,135	1,839	134	4.33	8.4	1,128	320
Integrated 2008	1,261	1,789	108	3.75	7.7	1,087	303
Integrated 1990-7% 2008	1,067	1,935	126	4.16	8.2	1,121	316
Integrated Sensitivity	1,444	1,617	101	3.52	7.6	1,074	299
2020 Results							
Reference	2,370	1,866	NA	3.14	6.0	993	288
NO_x Cap Cases							
NO_x 2005	2,335	1,894	NA	3.18	6.0	996	289
NO_x 2008	2,328	1,902	NA	3.15	6.0	995	289
SO_2 Cap Cases							
SO_2 2005	2,329	1,911	NA	3.20	6.0	995	289
SO_2 2008	2,339	1,901	NA	3.25	6.1	1,005	293
SO_2 Sensitivity	2,331	1,904	NA	3.17	6.0	996	289
CO_2 Cap Cases							
CO_2 1990-7% 2005	885	2,704	141	4.22	7.9	1,149	347
CO_2 1990-7% 2008	876	2,748	139	4.38	7.9	1,153	350
CO_2 Sensitivity	1,191	2,591	112	4.00	7.5	1,121	337
Integrated Cases							
Integrated 2005	1,000	2,752	113	4.04	7.6	1,127	338
Integrated 1990-7% 2005	852	2,774	130	4.30	7.8	1,146	345
Integrated 2008	998	2,746	116	4.32	7.7	1,140	343
Integrated 1990-7% 2008	834	2,816	129	4.42	7.9	1,148	347
Integrated Sensitivity	1,159	2,623	115	4.06	7.6	1,129	339

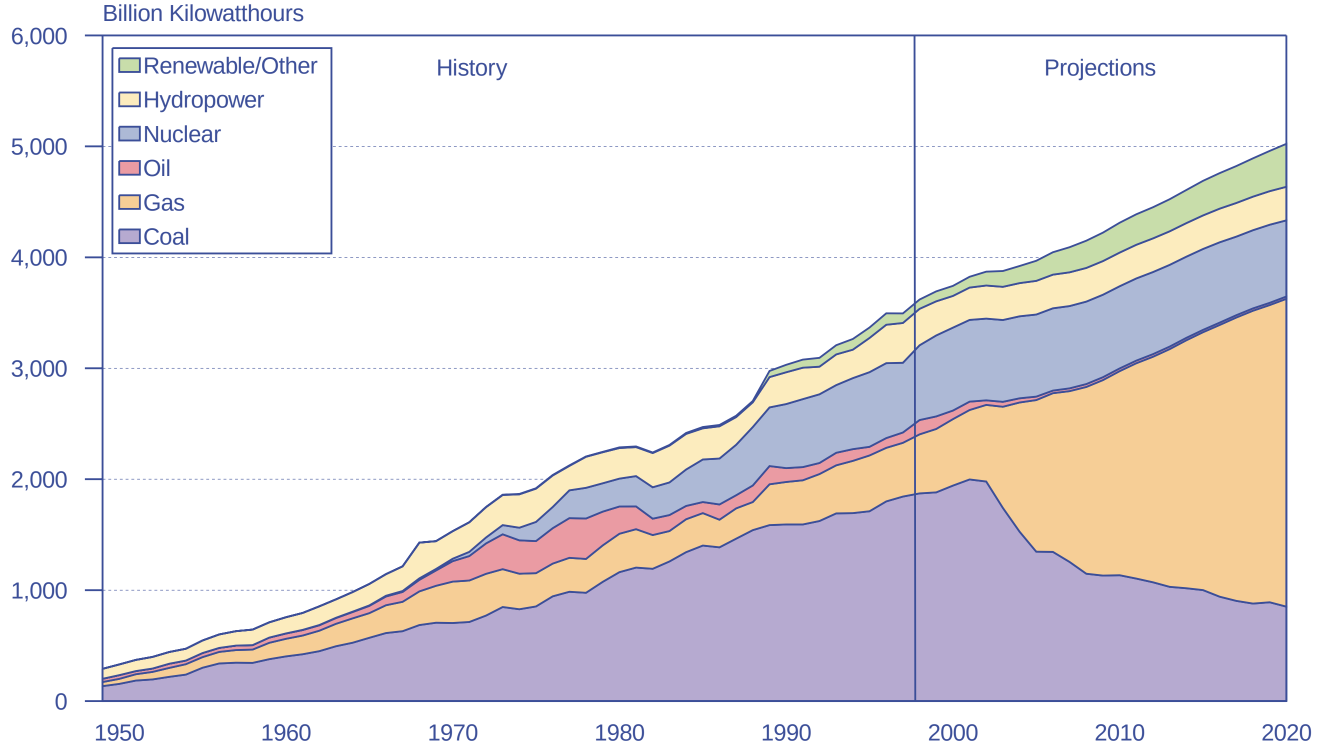
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

price of electricity if the plant did not set the market price. In such instances, the scrubber costs would reduce the profitability of the plant, but it might still remain economical to operate the facility.

The projections for SO_2 allowance prices are sensitive to variations in the assumed SO_2 emission target. SO_2 allowance prices are projected to be $735 per ton in 2010 in the SO_2 2005 case, but they are projected to be less than half that value, $300 per ton, in the SO_2 sensitivity case. The differences in the projections result from the less stringent emission target assumed in the SO_2 sensitivity case, which reduces the expected need to add emission controls at plants using relatively low-sulfur coal.

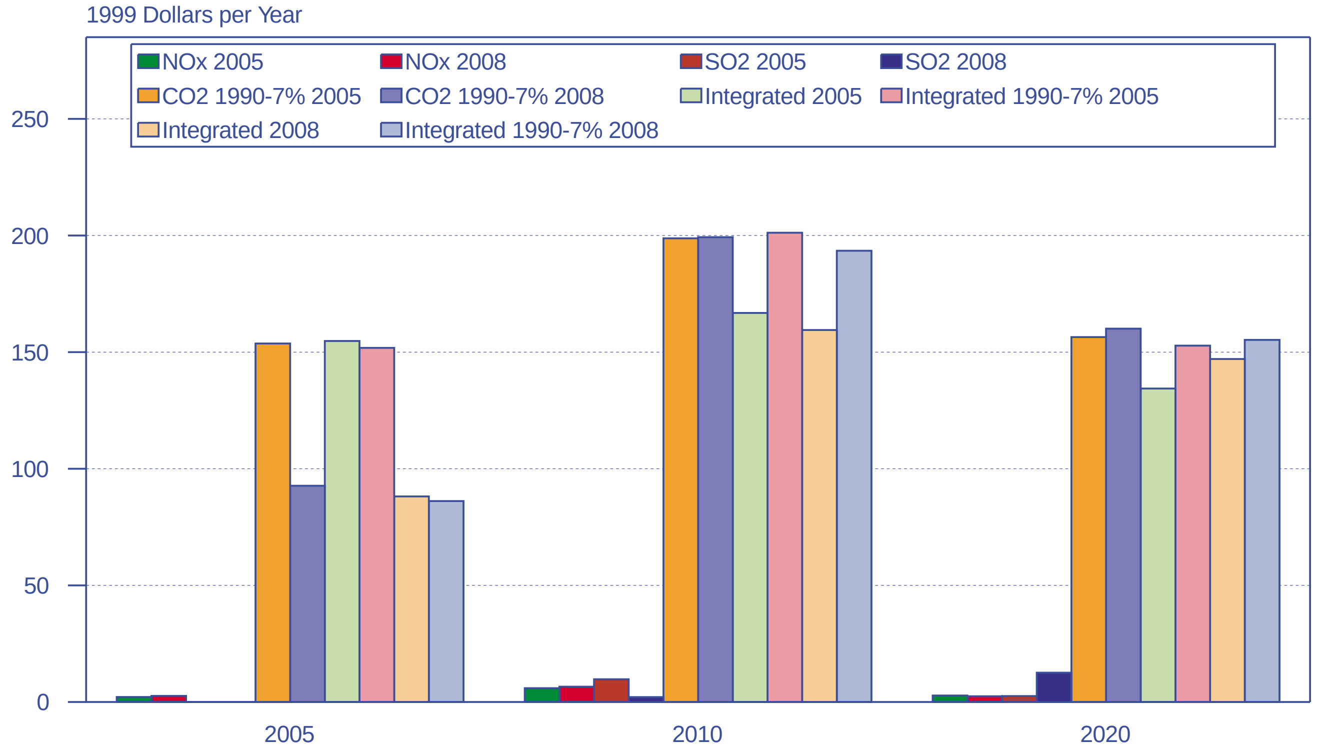
In all the analysis cases, consumers are projected to see higher electricity prices than those projected in the reference case (Figure ES2). In the NO_x cap cases the overall impact on electricity prices is projected to be fairly small,

Figure ES1. Electricity Generation by Fuel, 1949-1998, and Projections for the Integrated 1990-7% 2005 Case, 1999-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05.D121300B.

Figure ES2. Average Projected Changes in Annual Household Electricity Bills Relative to Reference Case Projections, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

approximately 1 percent above the reference case projection in 2010. Similarly, projected average electricity prices in 2010 in the SO_2 cap cases are only 1 percent above the reference case projection. In these cases, the projected costs of compliance are not large relative to the size of the industry, and not all the costs of compliance are expected to be passed on to consumers. As noted previously, however, installing the amount of control equipment projected to be needed in these cases could cause problems if it has to be done over a relatively short time period. The 2005 values shown in Figure ES2 do not incorporate the potential impact on prices of a large amount of capacity being out of service for retrofitting with emission control equipment.

In the cases with CO_2 caps, carbon allowance fees are expected to vary depending on the stringency of the emission cap. Among the cases with CO_2 caps, carbon allowance fees are projected to range between $71 and $120 per metric ton carbon equivalent in 2005, between $108 and $143 in 2010, and between $112 and $141 in 2020. In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 cap is projected to lead to carbon allowance fees that are lower than those projected in the comparable CO_2 1990-7% 2005 and integrated 1990-7% 2005 cases. In 2010, the carbon allowance fees projected in the CO_2 sensitivity case are between $37 and $41 per metric ton carbon equivalent less than those projected in the comparable cases with the more stringent CO_2 caps.

The impact on electricity prices is projected to be much larger in the CO_2 cap and integrated cases than in the NO_x and SO_2 cap cases. Because there are currently no commercially available technologies for removing and storing (sequestering) CO_2 and none is expected to be available during the projection period, the only way to make large reductions in CO_2 emissions is to reduce the consumption of fuels with relatively high carbon content and improve the efficiency of energy production and use. The combination of the projected CO_2 allowance costs, projected increases in operating costs for all fossil-fired generators, and projected increases in wellhead natural gas prices as power companies switch from coal to gas would lead to significantly higher electricity prices. Unlike in the NO_x and SO_2 cases, the operating costs for many of the plants setting the electricity market price are expected to increase, and consumer electricity prices are expected to increase with them.

In the integrated cases, projected electricity prices in 2010 range from 30 to 43 percent higher than in the reference case. Because electricity prices are expected to decline in the reference case, the projected price changes in the integrated cases are not as large when compared with current prices. For example, when compared to the 1999 price, electricity prices in the integrated cases are projected to be between 15 and 26 percent higher in 2010 and between 14 and 20 percent higher in 2020. The low end of the range is projected in the cases that assume a CO_2 emission cap at the 1990 level; the high end is projected in the cases that assume a cap of 7 percent below the 1990 level. For the average household, annual expenditures on electricity are projected to be between $147 and $201 (16 to 22 percent) higher than in the reference case in the integrated cases in 2010 and between $134 and $160 (14 to 16 percent) higher in 2020.

The impact of the assumed CO_2 emission caps on electricity prices is projected to be fairly sensitive to the stringency of the caps. For example, in the CO_2 1990-7% 2005 case, the price of electricity in 2010 is projected to be 42 percent above the reference case level. In the less stringent CO_2 sensitivity case, however, the difference is expected to be only 29 percent. Similarly, average electricity prices in 2010 in the integrated 1990-7% 2005 case are projected to be 43 percent higher than projected in the reference case, but in the integrated sensitivity case they are projected to be only 30 percent above the reference case projection.

Consumers are also projected to see higher natural gas prices because of the power sector's efforts to reduce emissions, especially CO_2 emissions. The increased use of natural gas in the power sector is projected to cause higher natural gas prices in all sectors of the economy, including the residential, commercial, and industrial sectors. In the integrated 1990-7% 2005 case, the Nation's natural gas bill, excluding gas used for electricity generation, is projected to be almost $25 billion higher than in the reference case in 2010. The $25 billion total estimate includes $6 billion for the residential sector, $4 billion for the commercial sector, and $15 billion for the industrial sector.

A coordinated approach to reducing power sector NO_x, SO_2, and CO_2 emissions such as that represented in the integrated cases in this report should lead to lower overall costs than would be incurred with different timetables for each of the emissions. As shown in this report, the compliance decisions that are projected when the NO_x and SO_2 caps are examined alone are different from those projected when the three emission caps are assumed to be combined. The exact savings would depend on the particular scenarios analyzed. The key factor is the timing of the NO_x and SO_2 caps relative to the timing of the CO_2 cap. On one hand, if NO_x and SO_2 caps were imposed and then followed shortly by a CO_2 cap that was unexpected, substantial investments could be made in control equipment that would later prove uneconomical. On the other hand, if the CO_2 cap preceded the NO_x and SO_2 caps, the potential for uneconomical investments in control equipment would appear to be small.

A rough measure of the maximum potential for savings in a coordinated approach would be to compare the cost increase projected in an integrated case with the sum of the cost increases projected in the cases that impose emission caps individually. Table ES5 shows the calculations for the integrated 1990-7% 2005 case and the standalone NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 cases with and without allowance fees. The values without allowance fees (often referred to as "resource costs") represent just the expected increases in expenditures on fuel and other operating costs and the increased investments in new emission control equipment and new capacity. The projected savings in total resource costs are higher in the early years—as much as $6 billion in 2006—because in the integrated cases the expected investments in control equipment to remove NO_x and SO_2 to meet the respective 2005 caps are less than those expected in the NO_x and SO_2 cap cases. After 2015, the projected savings in total resource costs are small. In the integrated case many of the plants to which controls might have been added are expected to be retired.

The projected higher prices for electricity and natural gas in the CO_2 cap and integrated cases would be expected to have an impact on the U.S. economy; however, because the emission caps are assumed to be applied only to electricity producers rather than to all energy producers and consumers, the impact is not expected to be large. In 2005 the projected impact on the U.S. unemployment rate in the integrated 1990-7% case is 0.6 percentage points above the reference case. In the same case, the projected impact on the Nation's gross domestic product (GDP) is projected to be a decline of 1.2 percent from the reference case projection. By 2020 the economic effect is projected to be reduced to a decline of 0.2 percent from the reference case projection.

Fuel Market Impacts

Coal

Because coal-fired power plants are the major power sector emitters of NO_x, SO_2, and CO_2, compliance with the emission caps modeled for this study would be expected to have a major impact on coal consumption and production, both nationally and regionally. The impacts are projected to be relatively small in the NO_x

Table ES5. Projected Changes from Reference Case Estimate of Total Costs of Service for U.S. Electricity Generators, 2005-2015
(Billion 1999 Dollars)

Year	NO_x 2005 Case	SO_2 2005 Case	CO_2 2005 Case	Sum: NO_x 2005, SO_2 2005, and CO_2 2005 Cases	Integrated 1990-7% Case	
					Projected Costs	Projected Savings
Including Allowance Costs in Total Costs						
2005	3	3	77	82	77	5
2006	4	3	70	77	68	9
2007	3	4	77	83	74	9
2008	3	3	89	96	87	8
2009	2	4	86	92	88	5
2010	2	4	88	94	86	9
2011	2	4	87	94	84	9
2012	3	5	90	97	87	11
2013	2	3	89	94	89	5
2014	3	3	89	96	87	9
2015	2	3	85	90	86	5
Excluding Allowance Costs from Total Costs						
2005	2	3	21	26	24	2
2006	3	4	20	28	22	6
2007	2	4	22	28	23	5
2008	3	3	27	32	28	4
2009	2	3	26	30	28	2
2010	2	3	28	33	28	5
2011	1	3	28	32	29	3
2012	1	3	29	34	29	5
2013	1	2	30	33	30	3
2014	2	2	31	36	31	4
2015	1	2	29	33	32	1

Note: Totals may not equal sum of components due to independent rounding.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

cap cases but more significant when SO_2 or CO_2 caps are assumed.

In the two primary SO_2 cap cases, reductions in coal-fired generation and coal consumption (on a Btu basis) are projected through 2020, as other fuels replace coal. Coal mines that supply medium- or high-sulfur coal are projected to have production declines, leading to lower projected minemouth prices for coal from those sources relative to the prices projected in the reference case. To meet the SO_2 emission caps, coal consumption is projected to shift dramatically to favor coal originating from the Powder River Basin in Wyoming and Montana, where surface mines working thick coal seams currently achieve levels of labor productivity that are on the order of 6 to 10 times greater than those in many other regions.

In the CO_2 cap cases, substantial reductions in coal consumption are projected, with corresponding drops in the projections for coal production. To reduce CO_2 emissions, the power sector is expected to move from coal to natural gas and, to a lesser extent, renewables. Because coal has a carbon content more than 70 percent higher per Btu than that of natural gas, the carbon allowance fees in these cases are projected to make the continued operation of many existing coal plants uneconomical.

To continue using coal in the CO_2 cap cases, a power plant operator would have to pay for the coal and for the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2005 case, the delivered price of coal in 2010 is projected to average \$0.92 per million Btu, and CO_2 allowances for coal are projected to cost \$3.65 per million Btu of energy obtained from coal combustion (\$143 per metric ton carbon equivalent). Thus, the effective cost of using coal is projected to be \$4.57 per million Btu in 2010 and \$4.41 per million Btu in 2020 in the CO_2 1990-7% 2005 case. The corresponding costs in the reference case are projected to be \$1.05 and \$0.98 per million Btu in 2010 and 2020, respectively. In all the cases with CO_2 caps, continued use of coal is projected to be uneconomical for many plants.

Total coal consumption is projected to be approximately 60 percent below the reference case level in 2020 in the cases with CO_2 caps. As existing coal-fired power plants become uneconomical in the CO_2 cap cases, large blocks of capacity are projected to be retired and replaced by natural gas capacity. The combined effects of lower coal capacity and lower utilization of the remaining coal capacity is projected to reduce coal consumption for electricity generation by 50 to 52 percent in 2010 relative to the reference case projection. Even in the CO_2 sensitivity and integrated sensitivity cases, coal use for electricity generation in 2020 is projected to be 35 percent lower than projected in the reference case.

Natural Gas

For natural gas consumption and production, the projected effects of emission caps are nearly the opposite of those for coal. Imposing emission caps on the power sector is expected to lead to greater use of natural gas, especially when a CO_2 cap is included. For example, in the integrated 1990-7% 2005 case, the electricity generation sector is projected to consume 4.0 trillion cubic feet more gas in 2005 than projected in the reference case, increasing its consumption by 250 percent over the next 5 years. In the case with an assumed compliance date of 2008, the projected increase in natural gas consumption is not as rapid, but it reaches nearly the same level by 2020.

To meet the expected growth in demand for natural gas, both domestic production and imports are projected to increase above the reference case levels. For example, in the integrated 1990-7% 2005 case, domestic production is projected to grow by 4.9 trillion cubic feet between 2000 and 2005, as compared with 2.1 trillion cubic feet in the reference case. Achieving the required levels of natural gas production projected in the CO_2 cap and integrated analysis cases would be a challenge to the industry. Domestic natural gas production grew by 5.7 trillion cubic feet between 1965 and 1970, but there has not been another period of such rapid growth since. It is expected, however, that investors would recognize that limits on CO_2 emissions would lead to higher demand for natural gas—and higher prices—for an extended period, and that the necessary investment in drilling equipment and other infrastructure would be made.

Imports of natural gas from Canada are also expected to play a role in reducing power sector CO_2 emissions. In the integrated 1990-7% 2005 case, imports from Canada are projected to reach 6.1 trillion cubic feet per year in 2020, 0.7 trillion cubic feet more than projected in the reference case. (The projections include growth in Canadian imports as a result of increased gas production in Alaska. New Alaskan gas that is not shipped directly to the lower 48 States is used in Canada, freeing up additional Canadian gas for export to the United States.)

The increased demand for natural gas projected in the cases that include CO_2 emission caps is expected to result in higher prices. For example, in the integrated cases, natural gas wellhead prices are expected to range from \$3.75 per thousand cubic fee to \$4.33 per thousand cubic feet in 2010, much higher than the \$2.68 price projected in the reference case. The highest prices are projected in the cases with 1990-7% CO_2 emission caps beginning in 2005, because of the more rapid increase in consumption projected in those cases and, consequently, the need for rapid increases in production. In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 emission caps assumed are expected to reduce the pressure on gas markets slightly and moderate the projected increase in natural gas wellhead prices relative to the reference case projections. For example, the projections of wellhead gas prices in 2020 are $4.00 per thousand cubic feet in the CO_2 sensitivity case and $4.06 in the integrated sensitivity case.

Renewables

Additional use of renewable energy sources is also expected as a result of efforts to reduce power sector emissions. As the cost of generating power from fossil fuels increases in the emission reduction cases, renewable generation technologies are expected to become relatively more attractive. The projected changes are small in the NO_x and SO_2 cap cases, where the costs of complying with the emission caps are expected to fall mainly on existing fossil plants. In the cases that assume CO_2 caps, however, when carbon allowance fees are added to the operating costs of fossil-fueled power plants, new renewable generating plants and biomass co-firing (mixing biomass with coal in an existing coal plant) are expected to become economically attractive.

The largest increases in renewable electricity generation in the integrated cases with CO_2 caps relative to the reference case are projected for geothermal, biomass, and wind. For example, geothermal electricity generation is projected to increase to 104 billion kilowatthours by 2010 in the CO_2 1990-7% 2005 case, as compared with the projection of 25 billion kilowatthours in 2010 in the reference case. The projection for biomass generation in 2010 (excluding cogeneration) increases from 22 billion kilowatthours in the reference case to 71 billion kilowatthours (17 billion kilowatthours from dedicated plants and 54 billion kilowatthours from co-firing in coal plants) in the CO_2 1990-7% 2005 case. Similarly, generation from wind plants in the CO_2 1990-7% 2005 case is projected to reach 18 billion kilowatthours in 2010 and 86 billion kilowatthours in 2020, as compared with the reference case projections of 12 and 13 billion kilowatthours, respectively. Overall, generation from nonhydroelectric renewables in the CO_2 1990-7% 2005 case is projected to make up 8.0 percent of total electricity generation and 8.5 percent of total electricity sales in 2020.

In the CO_2 sensitivity and integrated sensitivity cases, the amount of renewable capacity added—above the level projected in the reference case—is much less than projected in the cases with more stringent CO_2 caps. In the projections, the relative economics of new renewable capacity are sensitive to the projected carbon allowance fees. In the CO_2 sensitivity and integrated sensitivity cases, only 16 to 18 gigawatts more new renewable capacity is projected to be built than in the reference case by 2020, whereas in the CO_2 1990-7% 2005 case, which assumes the most stringent emission caps in this analysis, 46 gigawatts more new renewable capacity is projected to be built by 2020 than in the reference case.

Potential Impacts of New Source Review Actions

Requiring some or all coal-fired power plants to add equipment to reduce NO_x and SO_2 emissions to continue operating would have a significant impact on NO_x and SO_2 emissions. If the 32 plants currently under suit by the Department of Justice on behalf of the EPA are required to be retrofitted with best available control technology (BACT) to continue operating, as assumed in the NSR 32 case, it is estimated that the SO_2 allowance price in 2010 would be cut by 19 percent relative to the projection in the reference case, from $170 to $137 per ton. Total SO_2 emissions are expected to be 0.6 million tons below the reference case level, because it is assumed that the plants would surrender approximately half their allowances under the terms of an agreement to end the suit. In other words, the national SO_2 emission cap is expected to be lower, and to continue to be binding even after the actions taken by the plants that are being sued.

Similar behavior is expected in the NO_x allowance market. The price impact of requiring the 32 plants to add control equipment is projected to be small. As discussed above, most of the control equipment is expected to be added to plants that do not set the market prices for power, and thus the costs would not be fully passed on to consumers. Where equipment is added to plants in regions with cost-of-service regulation, the projected costs still are not large enough to have a significant impact on electricity prices.

The projected impacts on NO_x and SO_2 emissions and allowance prices are even larger in the NSR All case, which assumes that all coal-fired power plants must be retrofitted with control technology if they are to continue operating after 2010. In this case, both NO_x and SO_2 allowance prices are expected to fall to zero, because when new emission control equipment is added to all operating coal plants, NO_x and SO_2 emissions are projected to be well under established emission caps. For example, in the NSR All case, SO_2 emissions in 2010 are projected to be 1.9 million tons, well under the CAAA90 cap of 8.95 million tons.

A large number of coal plants—31 gigawatts (10 percent of existing capacity)—are expected to be retired in the NSR All case, because adding emission control equipment to them would not be economical. When those plants are retired, however, there would be insufficient baseload capacity (plants intended to run almost continuously) if they were not replaced. The vast majority of the plants retired are projected to be replaced by new coal plants that comply with new source performance standards. As a result, projected CO_2 emissions in the NSR All case are virtually unchanged from those in the reference case. As in the NSR 32 case, electricity prices in the NSR All case are expected to be only slightly above those projected in the reference case. Power plant owners are projected to spend roughly $15 billion on SCR NO_x controls and $58 billion on SO_2 controls, reducing the profitability of the plants but not making them uneconomical.

When the assumptions in the NSR 32 and NSR All cases are combined with those used in the integrated 1990-7% 2005 case described above, the results in the three cases are similar. Comparing the results in the integrated 1990-7% 2005, integrated NSR 32, and integrated NSR All cases shows that, to meet the emissions targets specified by the Subcommittee, the power sector is projected to reduce its use of coal dramatically and to increase its use of natural gas and, to a lesser extent, renewables (Table ES6).

The requirement that emission control equipment must be added to coal-fired plants if they are to continue operating in the integrated NSR All case is projected to lead to more coal plant retirements than projected in the integrated 1990-7% 2005 or integrated NSR 32 case, leading in turn to a lower CO_2 allowance fee in the integrated NSR All case. It is also projected to lead to even greater dependence on natural gas and, as a result, higher natural gas prices. Projected electricity prices are similar to those in the integrated 1990-7% 2005 case.

The NSR cases suggest that efforts to reduce NO_x and SO_2 emissions at existing coal-fired power plants would make a portion of the plants uneconomical, but the majority would continue operating. Additional effort would be needed to reduce power plant CO_2 emissions.

Uncertainty

As with all projections, there is considerable uncertainty in the results of this analysis. Among the key factors that influence the results are the significance of the changes; uncertainty about future fuel prices, particularly for natural gas; potential cost and performance improvements in emission control and generating technologies; the ability of the various energy markets to make the adjustments that would be needed over the next 5 to 8 years; the impacts of the ongoing changes in the structure of electricity markets; and the potential impacts of Hg emission regulations. All these factors could affect the results of this analysis.

Meeting the emission targets specified by the Subcommittee for this analysis would clearly be a challenge for the electricity industry and its associated fuel markets. The timing of the targets—only 5 to 8 years away—may pose the greatest challenge. Planning, siting, obtaining environmental permits for, and building the amount of new gas-fired capacity projected to be needed, as well as developing the natural gas resources that would be required to supply them, could be difficult in the time frame assumed here. Increasing reliance on natural gas in the power sector could place considerable stress on the gas production and delivery infrastructure, leading to price volatility and substantial upward pressure on gas prices. In addition, new technologies for electricity generation, emission controls, and natural gas exploration and development that might be developed over a

Table ES6. Integrated NSR Case Projections, 2000, 2010, and 2020

Analysis Case	Coal-Fired Generation (Billion Kilowatthours)	Gas-Fired Generation (Billion Kilowatthours)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)
2000					
Reference	1,942	599	570	0	6.8
Integrated 1990-7% 2005 . .	1,943	599	570	0	6.7
Integrated NSR 32.	1,942	603	570	0	6.7
Integrated NSR All.	1,940	607	569	0	6.7
2010					
Reference	2,284	1,123	686	0	5.9
Integrated 1990-7% 2005 . .	1,135	1,839	443	134	8.4
Integrated NSR 32.	1,086	1,903	438	132	8.4
Integrated NSR All.	1,031	1,988	442	92	8.1
2020					
Reference	2,370	1,866	776	0	6.0
Integrated 1990-7% 2005 . .	852	2,774	440	130	7.8
Integrated NSR 32.	869	2,755	439	122	7.7
Integrated NSR All.	802	2,856	442	112	7.8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction.
Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP_N32.D121900A, and FDP_ALL.D121900A.

longer period would not be able to contribute significantly to meeting the challenge in the short term.

A key uncertainty with regard to competitive power markets is how consumers and product developers might respond to competitively priced electricity. One feature that has been seen in newly competitive markets is a large amount of price volatility. Because such volatility has not occurred historically, consumers (including homeowners and commercial and industrial establishments) have not invested in equipment that could reduce their exposure to higher prices. It remains to be seen whether the market will become more responsive in the future.

1. Introduction

Over the next decade, power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), and mercury (Hg). At present, neither the future reduction requirements nor the complete timetable is known for any of these airborne emissions, and compliance planning is difficult. In response to the Clean Air Act Amendments of 1990 (CAAA90), power plant operators are now in the process of making reductions in power plant emissions of SO_2 and NO_x. Phase II of the CAAA90 SO_2 reduction program—lowering allowable SO_2 emissions to an annual cap of 8.95 million tons—became effective on January 1, 2000, and more stringent NO_x emissions standards for boilers also took effect in 2000. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, these emissions may have to be further 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 would take effect in 2004. Emissions of fine particles (less than 10 microns in diameter) and their impacts on health are currently being studied. Fine particles are associated with power plant emissions of SO_2, and further reductions in SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA recently decided that Hg emissions need to be reduced, and proposed regulations will be developed over the next 3 years. Further, if the United States ratifies the Kyoto Protocol or a similar international greenhouse gas mitigation treaty, energy-related CO_2 emissions will also have to be reduced.

With comprehensive standards changing according to different timetables, compliance planning is difficult. It can take several years to design, license, and construct new 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 far into the future to evaluate the economics of new investment decisions. Changing emission standards with different timetables add 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 may not be optimal if Hg and CO_2 emissions must also be reduced. Further complicating planning, some investments reduce multiple emissions simultaneously, such as 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.

Recently, plans have been proposed that would require coordinated multi-emission reductions. Several bills have been introduced in 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 (Table 1). Each of these bills 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, or combinations of the three—but all call for significant reductions.

H.R. 2900 calls for reducing power plant NO_x and SO_2 emissions by 75 percent from 1997 levels, reducing power plant CO_2 emissions to 1990 levels, and reducing power plant Hg emissions by 90 percent, all by 2005. In addition, it requires that older plants be modernized to comply with the most recent new source performance standards within 5 years of the bill’s passage.

S. 1369 has similar goals but takes a different approach, establishing explicit emission caps on NO_x, SO_2, CO_2, and Hg. The proposed annual caps are 1,660,000 tons for NO_x (approximately 73 percent below the 1997 level), 3,580,000 tons for SO_2 (approximately 73 percent below the 1997 level), 1,914,000,000 tons for CO_2 (the 1990 level), and 5 tons for Hg (a 90-percent reduction from the estimated 1997 level). The bill uses these caps to establish generation performance standards (GPS) to allocate emission allowances each year. For example, if the facilities subject to the emission cap generated a total of 2 billion megawatthours of electricity in a given year, the

Table 1. Congressional Bills With NO$_x$, SO$_2$, or CO$_2$ Power Plant Reduction Requirements

Bill Number	NO$_x$ Target (Tons per Year)	SO$_2$ Target (Tons per Year)	CO$_2$ Target (Tons per Year)	Hg Target (Tons per Year)	Other
S. 1369	1,660,000	3,580,000	1,914,000,000 (approx. 1990 level)	90% reduction	20% RPS, GPS, PBF
S. 1949	90% removal at each plant, and no more than 0.15 pounds per million Btu	95% removal at each plant, and no more than 0.3 pounds per million Btu	GPS, 0.9 pounds CO$_2$ per kilowatthour for natural gas, 1.3 for oil, and 1.55 for coal	90% reduction from 1997 level	None
S. 172, H.R. 25	3,000,000 (70% below 1990 level)	4,500,000 (50% below CAAA90 level)	No requirement	Study	NO$_x$ allowance program
H.R. 2645	1,660,000	3,580,000	1,710,000,000 in 2005 (10% below 1990 level); 1,425,000,000 in 2010 (25% below 1990 level); 380,000,000 in 2030 (80% below 1990 level)	Reduce to 0 by 2010	GPS, PBF, RPS, nuclear waste reductions
H.R. 2900	1,548,000 (75% below 1997 level)	3,273,000 (75% below 1997 level)	1,914,000,000 (approx. 1990 level)	90% reduction from 1997 level	Plants required to meet new plant standards when they reach 30 years of age
H.R. 2980	Approximately 1,831,925 (1.5 pounds per megawatthour using 1996-1998 average generation)	Approximately 3,663,850 (3.0 pounds per megawatthour using 1996-1998 average generation)	1,914,000,000 (approx. 1990 level)	70% reduction from level in flue gas	GPS for CO$_2$

CAAA90 = Clean Air Act Amendments of 1990. GPS = Generation Performance Standard (output based allocation of emission allowances). PBF = Public Benefits Fund. RPS = Renewable Portfolio Standard.

Sources: S. 1369, “Clean Energy Act of 1999,” 106th Congress, 1st Session (July 14, 1999); S. 1949, “Clean Power Plant and Modernization Act of 1999,” 106th Congress, 1st Session (November 17, 1999); S. 172, “Acid Deposition and Ozone Control Act,” 106th Congress, 1st Session (January 19, 1999); H.R. 2645, “Electricity Consumer, Worker, and Environmental Protection Act of 1999,” 106th Congress, 1st Session (July 29, 1999); H.R. 2900, “Clean Smokestacks Act of 1999,” 106th Congress, 1st Session (September 21, 1999); H.R. 2980, “The Clean Power Plant Act of 1999,” 106th Congress, 1st Session (September 30, 1999).

generation performance standard for CO$_2$ would be approximately 1 metric ton carbon equivalent per megawatthour (1,914,000,000 divided by 2,000,000,000). As a result, each generator would be allocated slightly less than 1 metric ton of emission allowances for each megawatthour generated for that year. Generators whose emissions exceeded their allocations of emission allowances would have to purchase credits from others. As generation changes over time, the GPS and the allocation of future allowances would also change.

S. 1369 also establishes a public benefits fund (PBF) created by collecting a small fee for each kilowatthour of electricity sold and used to support energy efficiency and renewable energy projects and to assist low-income households in meeting their energy needs. In addition, S. 1369 also would establish a renewable portfolio standard (RPS). The RPS requires that a specified share of generation sold by covered generators (all nonhydroelectric generators) must come from renewable sources. Those with qualifying renewable generation are to be issued credits that they can use to meet their own requirements or sell to others who do not generate the required share themselves. The required share begins at 2.5 percent in 2000 and grows to 20 percent in 2020.

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.[1] 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 and RPS requirements. This report examines NO$_x$, SO$_2$, and CO$_2$ emission limits. A second volume, to be published in early 2001, will examine Hg emission limits and RPS requirements.

This report provides an analysis of the potential impacts of efforts to reduce NO$_x$, SO$_2$, and CO$_2$ emissions from power plants, based on scenarios requested by the Subcommittee on June 29, August 17, and September 25, 2000. Expected costs to the energy sector and to consumers of meeting the specified emission caps are examined (see Chapter 2 for a discussion of the specific scenarios requested). The potential benefits of reduced emissions—such as might be associated with reduced health care costs—are not addressed, because EIA does not

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[1] The letters requesting this study are included in Appendix J.

have expertise in this area.[2] The bibliography for this report includes several studies that address the benefits of reducing emissions. Readers should refer to the EPA and others for analysis of the potential benefits of emissions reductions.

In response to a later request from the Subcommittee, this analysis also includes four scenarios examining the potential impacts of requiring older coal-fired power plants either to be brought into compliance with current new source performance standards or to be retired. The EPA has taken action against the owners of 32 older coal plants, accusing them of making modifications without adding the emissions control equipment required by CAAA90. The first of the four scenarios—referred to as the New Source review (NSR) cases—assumes that the owners of each of the 32 plants will be required to add state-of-the-art emissions control equipment by 2005, or retire the plant if that is the economical choice. The second NSR case assumes that all coal-fired plants that currently do not have such control equipment must make the same decision by 2010. The third and fourth NSR cases are the same as the first two, except that they include caps on power sector emissions of NO_x, SO_2, and CO_2. Because Tampa Electric has settled its case, all the scenarios in this report assume that control equipment will be added to its Big Bend facility and that its F.J. Gannon plant will be converted to natural gas.

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 by the Subcommittee. 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. For example, all the analysis cases assume that market participants—power suppliers, consumers, and coal, gas, and renewable fuel suppliers—would become aware of impending emission caps before their target dates and would begin to take action. If market participants do not anticipate the emission caps or foresee them earlier, the results would change. For example, in earlier EIA studies 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.[3]

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 to be consequences of specific legislative proposals. All the proposals include provisions other than the emission caps studied in this analysis, and several would use different policy instruments to meet the emission targets. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be otherwise required as a result of ongoing environmental programs whose requirements currently are not specified (see discussion in Chapter 2, page 6).

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[2] Reports by Burtraw, Chestnut, and the EPA cited in the bibliography of this report include discussions of health benefits.

[3] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998); and *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999).

2. Analysis Cases and Methodology

Analysis Cases

The House Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs requested that EIA prepare an analysis to evaluate the impacts of potential caps on power sector emissions of NO_x, SO_2, CO_2, and Hg, combined with a renewable portfolio standard (RPS) requirement. The specific assumptions and cases requested by the Subcommittee are summarized in Table 2. To respond to the Subcommittee's request in a timely manner, the analysis has been divided into two volumes. This report addresses scenarios with NO_x, SO_2, and CO_2 emission caps, as well as scenarios analyzing the potential impacts of ongoing litigation that could require many existing coal plants to add state-of-the-art emissions control equipment. The latter cases, referred to as new source review (NSR) cases, are discussed in Chapter 5.

The reference case for this analysis incorporates the laws and regulations that were in place as of July 1, 2000, as EIA's *Annual Energy Outlook 2001* (*AEO2001*) was being prepared. 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." The settlement agreement between the Tampa Electric Company and the Department of Justice (acting for the U.S. Environmental Protection Agency) 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 is incorporated in the analysis.

Table 2 summarizes the emission targets, timetables, and RPS requirements for each case requested by the Subcommittee. The emission caps (Table 3 and Figure 1) are applied only to the electricity generation sector and are assumed to cover emissions from both utility-owned and independent power plants, excluding cogenerators. If economical, cogenerators are allowed to compete against other power plants to meet the demand for electricity. Because no requirements to reduce emissions in the residential, commercial, industrial, and transportation sectors are assumed, the results of this analysis should not be compared with the results of studies that have examined the impacts of complying with the Kyoto Protocol across all sectors of the economy.

In addition to the cases requested by the Subcommittee, this report includes three cases that assume less stringent emission caps for SO_2 and CO_2 only, and a combined integrated case that uses the less stringent targets (Table 4). These cases were analyzed to examine the sensitivity of the results to the emission targets requested by the Subcommittee for analysis. The emission caps in the SO_2 sensitivity case were set roughly halfway between the estimated emissions for 2000 and the caps requested by the Subcommittee—roughly a 50-percent reduction from 1997 levels, rather than the 75-percent reduction specified by the Subcommittee. For CO_2 a similar approach was used. The CO_2 cap in 2005 in the CO_2 sensitivity case was set to halfway between the estimated emissions in 2000 and the 1990 level. The cap was then lowered further over the 2008 to 2012 time period to halfway between the estimated 2000 emissions and 7 percent below the 1990 level. Using this approach, the CO_2 cap in 2005 in the CO_2 sensitivity case was assumed to be 10 percent above 1990 levels, before declining to 7 percent above 1990 levels over the 2008 to 2012 time period.

Using data that recently have become available, the National Energy Modeling System (NEMS) is currently being modified to represent power sector Hg emissions. The expected impacts of the other provisions in each case on Hg emissions are mentioned in Chapter 3, but the proposed Hg emission caps will be analyzed more thoroughly in the subsequent report.

In all cases it is assumed that emission caps would be phased in beginning in 2002. For the cases that require that CO_2 emissions average 7 percent below the 1990 level over the 2008 to 2012 time period, the cap is constructed so that emissions can be 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.[4] In addition, it is assumed that the emission reduction programs will be operated as market-based emission cap or fee programs, and the emission allowance prices or emission fees are included in the operating costs of plants that produce one or more of the emissions.

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[4] The Kyoto Protocol requires the United States to reduce its greenhouse gas emissions to 7 percent below the 1990 level on average between 2008 and 2012. Requirements for the post-2012 period have not been set. As requested by the Subcommittee, this analysis assumes that the CO_2 cap does not change after 2012.

Representation of New Environmental Rules and Regulations

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

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

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

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

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 their power plants when major modifications were made. CAAA90 requires that when major modifications are made to older power plants they must also be upgraded to comply with the emissions standards for new power plants. The EPA is arguing that the seven companies and the Tennessee Valley Authority made major modifications to 32 power plants but did not add the required emissions control equipment. At this time, one company, Tampa Electric, has settled the case by agreeing to make modifications to its power plants. The other cases have not been settled.

At the request of the Subcommittee four alternative reference cases with different assumptions about the outcome of the ongoing litigation were examined for this analysis. In the first New Source Review (NSR) case, it is assumed that the owners of each of the 32 plants against which the EPA has taken action will be required to add best available control technology to remove SO_2 and NO_x or retire the plant by 2005. In the

(continued on page 7)

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

Representation of New Environmental Rules and Regulations (Continued)

second NSR alternative reference case it is assumed that all coal-fired plants that do not have flue gas desulfurization (FGD) or selective catalytic reduction (SCR) equipment will be forced to add controls or retire by 2010. The third and fourth NSR cases are the same as the first two, except that they include caps on power sector emissions of NO_x, SO_2, and CO_2. The model evaluates the economics of the retrofit versus retirement decision for each plant. The resolution of these issues could have an impact on future power plant emissions, especially SO_2 and NO_x emissions.

Readers should keep in mind that some of the projected actions and costs incurred to comply with the emissions caps analyzed in this report may also result from the other pending rules and regulations discussed above when they are finalized.

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

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. In other words, they can use allowances they have banked. 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 their banked allowances are exhausted.

For this analysis, it is assumed that the power sector must explicitly reduce its emissions to meet the CO_2 cap and cannot rely on other mechanisms, such as the flexibility measures included in the Kyoto Protocol that allow countries several options for meeting their emission reduction targets, including direct emissions reductions, land use changes, and forestry changes. For example, 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 is also 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 count toward meeting a country's emissions cap. At this time, rules about what type of land use and forestry projects could be implemented and how emissions trading programs might work have not been finalized. If similar provisions were included in a program to reduce power sector CO_2 emissions, the costs of meeting the target most likely would be lower.

After its initial request, the Subcommittee asked that EIA also examine the potential impacts of requiring older coal-fired power plants either to be brought into compliance with current new source performance standards or to be retired. The EPA has taken action against the owners of 32 older coal plants accusing them of making modifications without adding the emissions control equipment required by CAAA90. The first of the four cases—referred to as the New Source Review (NSR) cases—assumes that the owners of each of the 32 plants will be required to add state-of-the-art emissions control equipment by 2005 or retire the plant. The second case assumes that all coal-fired plants that currently do not have such control equipment must make the same decision by 2010. The third and fourth cases combine the assumptions of the first two with more stringent caps on NO_x, SO_2, and CO_2 emissions.

Methodology

AEO2001 Assumptions

The analysis in this report is based on the data and NEMS algorithms used for the *AEO2001*.[5] Because the *AEO2001* forecasts are based on data available at the end of August 2000, the results of this analysis should be evaluated in terms of the relative differences between cases rather than the absolute values.

NEMS Representation

NEMS is a computer-based, energy-economic model of the U.S. energy system for the mid-term period, through 2020.[6] 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. Domestic energy markets are modeled by explicitly representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most sectors, NEMS

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[5] For a summary of the *AEO2001* assumptions, see web site www.eia.doe.gov/oiaf/assumption/.

[6] For a more detailed overview of NEMS, see Energy Information Administration, *The National Energy Modeling System: An Overview 2000* (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/index.html.

Table 2. Analysis Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
Volume 1 Cases						
NO_x Cap Cases						
NO_x 2005	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2005	None
NO_x 2008	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2008	None
SO_2 Cap Cases						
SO_2 2005	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2005	None
SO_2 2008	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2008	None
CO_2 Cap Cases						
CO_2 1990-7% 2005	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2005; 7% below 1990 level in 2008-2012	None
CO_2 1990-7% 2008	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2008; 7% below 1990 level in 2008-2012	None
Integrated Cases						
Integrated 2005	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2005	None
Integrated 1990-7% 2005	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; CO_2 1990 level by 2005; 7% below 1990 level in 2008-2012	None
Integrated 2008	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2008	None
Integrated 1990-7% 2008	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012	None
Volume 2 Cases						
Mercury Case	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	90% below 1997 level	Start 2002; meet target by 2005	None
RPS Case	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	None	None	5% 2005, 10% 2010, 20% 2020
Integrated Cases with Renewable Portfolio Standard						
Integrated RPS 2005	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet target by 2005	5% 2005, 10% 2010, 20% 2020
Integrated RPS 1990-7% 2005	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; NO_x/SO_2/ Hg targets by 2005; CO_2 1990 level by 2005, 7% below 1990 level in 2008-2012	5% 2005, 10% 2010, 20% 2020
Integrated RPS 2008	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet target by 2008	5% 2005, 10% 2010, 20% 2020
Integrated RPS 1990-7% 2008	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; NO_x/SO_2/ Hg targets by 2008; CO_2 1990 level in 2008, 7% below 1990 level in 2008-2012	5% 2005, 10% 2010, 20% 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 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target of 7 percent below 1990 levels is between 2008 and 2012. The cap is then held constant at that level through 2020. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: See requesting letters in Appendix J.

Table 3. 1990 and 1997 Emissions Levels and Assumed Emission 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	50
1997 Level	6,191	13,090	533	50
Emission Caps	1,548	3,273	440[a]	5

[a] The integrated 2005 and integrated 2008 cases set CO_2 emissions to the 1990 levels.

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).

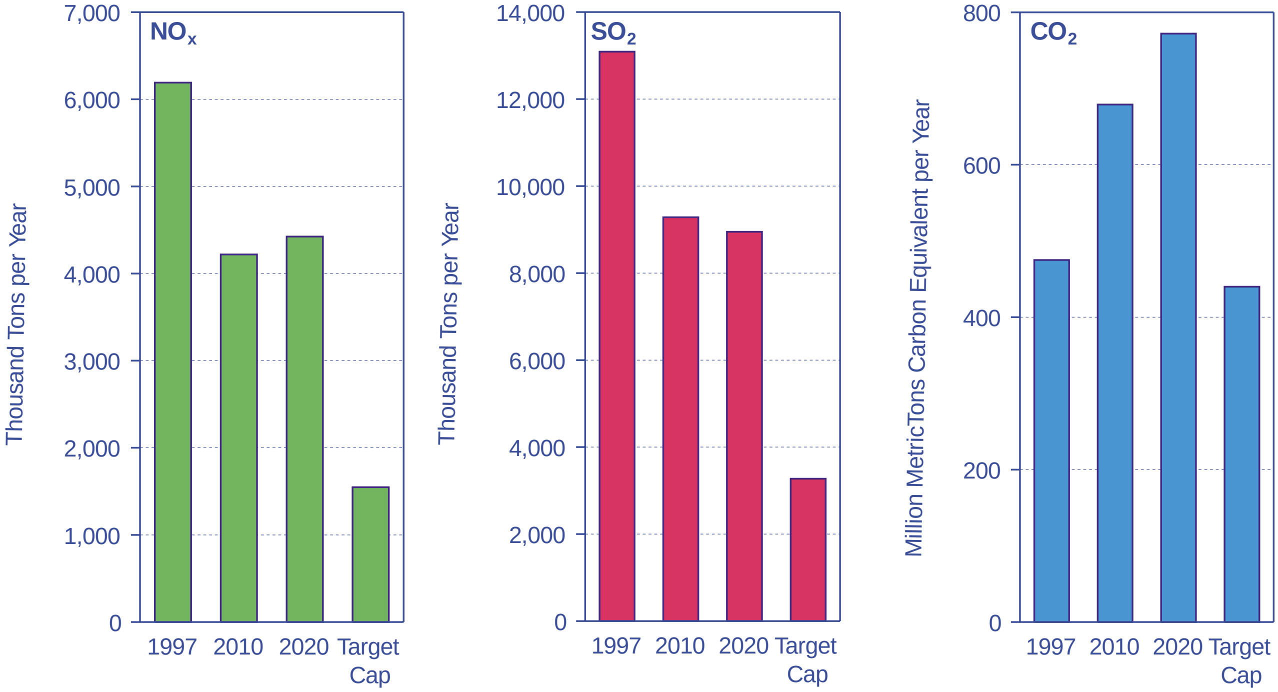
Table 4. Assumed Emission Caps for Electricity Generators in Sensitivity Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
SO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	None	None	Start 2002; meet target by 2005	None
CO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% above 1990 level	None	Start 2002; reach 10% above 1990 CO_2 level in 2005 and 7% above 1990 level in 2008-2012	None
Integrated Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	7% above 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; for CO_2, reach 10% above 1990 level in 2005 and 7% above 1990 level in 2008-2012	None

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 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target 7 percent above 1990 levels is between 2008 and 2012. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: Office of Integrated Analysis and Forecasting.

Figure 1. 1997 Emissions, Reference Case Projections for 2010 and 2020, and Target Caps for Electricity Generators



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.

includes explicit representation of energy technologies and their characteristics (Table 5). In each sector of NEMS, economic agents—for example, representative households in the residential demand sector—are assumed to evaluate the cost and performance of various energy-consuming technologies when making their investment and utilization decisions. The costs of making capital and operating changes to comply with laws and regulations governing power plant and other emissions are included in the decisionmaking process.

The rich detail in NEMS makes it useful for evaluating various energy policy options. Policies aimed at a particular sector of the energy market often have spillover 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 approach for this analysis are also explained.

Table 5. 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).

Representation of NO_x, SO_2, and CO_2 Emission Reduction Programs

In this analysis, it is assumed that the programs set up to reduce NO_x, SO_2, and CO_2 emissions from power plants will operate like the existing SO_2 program established in Title IV of CAAA90, and that marketable emission allowances or permits will be allocated to power plant operators at no cost (no revenue will be collected by the government). No assumption is made about the specific allocation methodology to be used, other than that it will be a fixed allocation (does not change from year to year) and the total amounts allocated will equal the national emission targets for NO_x, SO_2, and CO_2. Holders of allowances are assumed to be free to use them to cover emissions from their own 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 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 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. 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 (see box on page 12). The choice of policy instrument will have an impact on the costs of complying with the emission targets and the electricity price and income impacts seen by consumers. The analysis does not employ a generation performance standard as is proposed in several bills (see box on page 14).

Electricity Market Module

The representation of laws and regulations governing power plant emissions is particularly important in the NEMS electricity market module (EMM). The EMM is able to simulate emission caps on SO_2, NO_x, and CO_2. In the reference case for this analysis, the CAAA90 SO_2 emission cap, both Phase I and Phase II, is included. The summer season NO_x emission cap (SIP Call) promulgated by the EPA is also included for 19 States, as discussed above. 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 EMM evaluates the need for new generating capacity to meet consumer needs reliably or to replace existing 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.[7] For nuclear facilities the 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.

The EMM does represent 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. In the EMM it is assumed that the costs for new technologies decline with each doubling of capacity. As a result, if a policy stimulates the development of a particular technology the EMM 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.

During each time period plants are brought on line (dispatched), starting with the unit with the lowest operating costs, until consumers' demand is met. When faced with an SO_2 or NO_x emission cap 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 producing 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, or retiring a relatively high emitting plant and replacing it with a cleaner plant or, through higher prices, encouraging consumers to reduce their electricity use. This approach allows for 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 the capped emissions.[8] In NEMS, SO_2 allowance banking decisions can be specified exogenously, or the model can solve for them endogenously. In this analysis, because of stability problems caused by the relationships among the emission caps, banking patterns were specified exogenously for

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[7] The capacity planning algorithm determines the appropriate reserve margins in each region by weighing the probability of blackouts (loss of load) and consumers' willingness to pay to avoid them against the cost of building new capacity.

[8] See Appendix K for control costs.

Implementing Emission Caps: Cost and Price Impacts

When emission caps are imposed in the electricity sector, power suppliers can be expected to take actions to reduce those emissions. In some cases they will add emissions control equipment, such as flue gas desulfurization equipment to reduce SO_2 and selective catalytic reduction equipment to reduce NO_x emissions. Depending on the economics, they might also choose to retire some existing generating plants and replace them with plants that have lower emissions. For example, they might retire existing coal-fired plants and replace them with plants that use natural gas or renewable fuels to reduce CO_2 emissions. In turn, in response to price changes, consumers would be expected to reduce their consumption of electricity by increasing their use of non-electric appliances, changing their usage patterns for electric appliances, and investing in more efficient electricity-using equipment.

Each of these actions will have costs. For the power sector, there will be costs associated with increased investments in control equipment and new generating plants. There may also be higher costs associated with maintaining and operating new emission control equipment. Similarly, if new plants require more expensive fuel (i.e., natural gas rather than coal), total fuel costs would also be higher. There also could be costs associated with purchasing and holding emission allowances (or paying fees) on unabated emissions. The degree to which such costs are reflected in consumers' electricity prices (inducing them to reduce their consumption of electricity) and the impact on the economy will be affected by numerous factors.

A variety of policy instruments may be used in efforts to reduce electricity sector emissions. Possible approaches include explicit emissions or technology standards for all generators, a fee on targeted emissions, and marketable (tradable) emission permits assigned or auctioned to generators based on historical emissions (grandfathering) or current year output (such as through the use of a generation performance standard). Each of these policy instruments has cost and price implications.[a]

This analysis assumes a marketable emission permit approach modeled after the SO_2 allowance program created in CAAA90. It is assumed that emission permits or allowances would be provided to affected sources by the regulatory authority, and that the total number of allowances issued to all affected parties would be equal to the national target emissions cap. To be in compliance each year, the number of allowances held for each affected source would have to be equal to or larger than their emissions. Allowances held for an affected source that are not needed could be sold to others.

As allowances are bought and sold a market price will develop for them. Power suppliers will use this price to decide whether to reduce their emissions or purchase allowances to cover them. When deciding whether or not to operate a facility that produces emissions subject to a cap, the owner will include the market price of the allowance as part of the operating costs of the plant. As with fuel, operating the plant will consume an asset—the allowance—that could be sold if the plant were not operated.

The costs associated with the investment and operating decisions made by power suppliers to meet the emissions cap together with the costs of acquiring emission allowances will affect the market price for electricity. In competitive markets the generation price is based on the variable operating costs (what economists refer to as "marginal costs") of the plant setting the market price at any given point in time. In other words, the running plant with the highest operating cost generally sets the market price for power. Typically, for fossil fuel plants, operating costs are dominated by fuel costs, with only a small portion coming from other operating and maintenance costs. If the costs of the plant setting the market price for power are increased by expenditures associated with running new pollution control equipment, using higher cost fuel, and / or purchasing allowances to cover its emissions, the competitive market price for power will reflect those costs. Thus, the total price impact of implementing the emission cap program will include changes in resource costs (i.e., higher operating and maintenance costs and higher fuel costs) together with the allowance purchase costs that raise the operating costs of the plants setting the market price.

While power markets[b] in the United States are becoming increasingly competitive, they are not fully competitive today. In some areas of the country, prices are not set by the marginal costs of producing power. Rather, they are set by dividing the total costs (i.e., fuel costs, operating maintenance costs, capital recovery costs, and a regulated return on investment) by the amount of power sold. In such markets, the costs associated with adding emission control equipment,

(continued on page 13)

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

[b] This discussion refers only to the generation sector of the electricity market. The transmission and distribution sectors are assumed to continue to price their services on a cost-of-service basis.

Implementing Emission Caps: Cost, and Price Impacts (Continued)

switching fuels, and building replacement plants to reduce emissions would be added to the aforementioned total costs and a new price would be derived. The treatment of allowance costs will depend on how they are allocated and whether the public service commission in a particular State requires costs (or profits) from allowance transactions to be recovered from (or returned to) customers or borne by shareholders. However, because of the increasing role played by wholesale power market transactions and the dominance of independent power producers (IPPs) in building new capacity this analysis assumes that allowance costs will be included in the operating costs of power producers in regulated markets.

It is expected that, even in regulated cost-of-service regions, IPPs will dominate new power plant additions, and because they will have to purchase allowances to cover their emissions, the allowance costs will be included in their competitively priced power contracts with utilities. In the latest data supplied to EIA, utilities reported plans to add 10,623 megawatts of capacity between 1999 and 2003. Over the same time period nonutilities reported plans to add 61,456 megawatts, or 85 percent of the total. As a result, in this analysis it is assumed that IPPs will build all new power plants and sell the electricity at market-based rates—which will include the costs of needed emission allowances.

If the pace of deregulation slows and electricity prices continue to be set on a cost-of-service basis, then assuming that allowance costs would be reflected in the operating costs of all plants with the targeted emissions may overstate the price impacts. The operating costs for existing regulated plants that received allowances at no cost would not include the opportunity costs of holding allowances.

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. 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 natural gas and renewables), changes in operations of existing and new power plants (using lower emitting resources more intensively than higher emitting resources), and conservation activities by consumers (induced by higher prices). The model solves for the allowance price that encourages power suppliers and consumers to make changes in investment, operations, and conservation activities.[9] 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. When multiple emissions caps are imposed, the model solves for the most economical way to meet all of them simultaneously.

The steps taken to reduce NO_x, SO_2, and CO_2 emissions affect the price of electricity. The EMM has the option to price power (the generation component of the energy 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. For this reason, this analysis treats the allowance prices that arise when emission

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[9] The EMM represents coal- and gas-fired generating technologies with carbon removal and sequestration equipment, but the technologies are not cost-effective in the time frame of this analysis.

Generation Performance Standards

Several of the bills proposing multi-emissions strategies for the electric power sector call for the use of a policy instrument different from the allowance allocations assumed in this analysis—an instrument referred to as a generation performance standard (GPS). The approach used in this report is based on the existing SO_2 program, where emission allowances are allocated to generating plants at the beginning of the program without charge, and the allocations do not change over time. In contrast, under a dynamic GPS approach, allowances would be reallocated each year, based on a plant's megawatthour output. For example, if the national cap on CO_2 emissions were set at 1.914 billion tons (the 1990 CO_2 emission level for the electricity sector) and the total generation for all covered plants[a] equaled 4 billion megawatthours in a particular year, the GPS would equal 0.479 tons CO_2 per megawatthour generated (0.119 metric tons carbon equivalent). Because the generation from covered facilities is expected to change over time, the GPS would be recalculated annually.

A dynamic GPS allowance allocation scheme as described above ("dynamic" because the allocation is revised each year) would lead to different cost and price impacts from those shown in this report. The one-time fixed allowance allocation scheme assumed in this report results in the full allowance price becoming part of the operating costs for all plants producing the targeted emission. For example, if a plant produced 0.200 metric tons of carbon (0.733 tons CO_2) per megawatthour and the carbon allowance price was $100 per metric ton, the operating costs of that plant would increase by $20 per megawatthour ($100 × 0.2). Under the dynamic GPS approach the impact on the same plant's operating costs would be lower. Using the GPS value from the previous paragraph, the plant would need to purchase allowances equal to the difference between its emission rate and the GPS rate—or 0.200 minus 0.119. As a result, the plant's operating costs would only increase by $8 per megawatthour ($100 × [0.200 – 0.119]). If the sample plant were a price-setting plant, the net effect of the dynamic GPS allowance allocation scheme would be that the full cost of holding allowances for the plant ($20 per megawatthour) would not be passed on to consumers. In effect, the plant would receive an output rebate or subsidy of $12 for each megawatthour produced, and the subsidy would be passed on to consumers in the form of lower electricity prices.

Because the full marginal cost of reducing emissions would not be passed on under the GPS scheme, consumers would have a smaller incentive to reduce their electricity consumption than they would with the fixed allowance allocation scheme used in this analysis. Consequently, power suppliers would need to take additional steps to meet the various emission targets, in order to compensate for a smaller demand response from consumers. They would have to reduce coal consumption and increase natural gas and renewable fuel consumption more than they would under a fixed allowance allocation program. The increased use of natural gas can be expected to lead to higher gas prices and, in turn, a higher allowance price to stimulate further reductions.

In comparison with the results presented in this report, the use of a dynamic GPS allowance allocation scheme would be expected to lead to a smaller increase in the price of electricity but higher natural gas prices and a higher CO_2 allowance price. The degree to which natural gas and CO_2 allowance prices would be higher would depend on the expected responsiveness of consumers to higher electricity prices and the sensitivity of the natural gas market to additional demand from the electricity sector.

In this analysis, the natural gas sector is projected to have to increase production by record levels to meet the 2005 CO_2 emission targets, and additional increases in demand from the electricity sector could lead to significant price increases above those already projected. As one expert puts it, "output based rebating sacrifices some of the efficiencies of market-based environmental policies. Allocating by market share essentially provides a subsidy to output, which creates a bias away from output substitution and toward emissions rate reduction. The result is a higher marginal cost of control, a lower equilibrium output price, and a greater cost to achieving any given level of emissions reduction, compared to an efficient policy. The size of the welfare loss from this distortion depends on how much emissions reduction would normally be performed by output substitution."[b]

[a] The definition of "covered units" can differ. In some cases allowances would be allocated to all generating plants; in others they would be allocated only to fossil-fired plants.

[b] C. Fischer, *Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, January 21, 1999).

caps are imposed as if they were imposed on competitive markets. The allowance prices become part of the operating costs of power plants that produce the targeted emissions.[10]

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. An additional adjustment is made to reflect consumers' willingness to pay for reliable service, especially during high usage periods. When emission caps are imposed, the allowance costs or fees associated with them become part of the operating costs for power plants that produce the affected emissions. As a result, in competitively priced regions, the fees or allowance costs for SO_2, NO_x, and CO_2 become part of the operating costs for 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 owning plants for which emission reduction costs are below the marginal reduction costs. Equally important is the assumption that when the costs fall on plants that do not set the market price, their owners will not be able to pass any of them on to consumers. In regulated regions, the total costs associated with adding emissions control equipment, using higher cost fuels, and retiring or replacing plants to reduce SO_2, NO_x, and CO_2 emissions are recovered along with the costs of holding allowances and other costs.

To represent the RPS (to be analyzed in the forthcoming volume), the EMM has the ability to require that generation from nonhydroelectric renewable facilities (including cogenerators) be greater than or equal to 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 operated as a market credit system. It is not required that each power seller produce or purchase the required renewable share. As an alternative, they must hold renewable "credits" equal to the required share. Credits are issued to those 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.[11]

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 of 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.

The CMM uses a linear programming algorithm to determine the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region. Separate supply curves are developed in the CMM for each of 11 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). The modeling approach used to construct the 35 regional coal supply curves represented in the CMM 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).

More than 90 percent of U.S. coal production is consumed domestically, and electric utilities and independent power producers account for approximately 90 percent of U.S. consumption. 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 are consumed in the combined residential and commercial sector annually.

Coal is heterogeneous in terms of its energy, sulfur, nitrogen, carbon, and mercury 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 the resultant level of emissions. Coal prices also vary significantly based on the heat content, quality, and regional source of the coal. 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 in the amount of coal originating from each region, can lead to changes in U.S. average minemouth prices across cases that are

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[10] Competitive prices are applicable only to the generation sector of the electricity market. Prices for transmission and distribution services are assumed to continue to be based on cost-of-service regulation.

[11] The Administration's proposed Comprehensive Electricity Competition Act (CECA) limits the credit price to 1.5 cents per kilowatthour.

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 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 sulfur cap (expressed in tons of SO_2) that represents 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 cap. The allowance price is calculated from this methodology; it is essentially the cost of reducing the last ton of SO_2 under the cap. This allowance price, in turn, is used by the EMM to evaluate the economics of adding FGD equipment to coal-fired generators.

For the most part, the CMM configuration used for the reference case of this study is the same as was used for the *AEO2001*. Certain sections of the linear program layout were restructured to provide a simplified format and improved maintenance and reporting. Other sections of the linear programming code were redesigned to accept case-specific factors to permit a generally smooth drawdown of sulfur allowance banks from current levels (as of 2000) to zero in 2010 for all cases except the sulfur cap cases, which reach zero in 2015. The latter change results in different levels and timing for scrubber retrofits relative to *AEO2001*.

All the analysis cases, with the exception of the NO_x cap cases (which have relatively minor impacts on U.S. coal demand), incorporate two additional changes to the CMM assumptions used for the reference case. All coal contracts (between shippers and utilities) were modified to be phased out no later than 2003. In addition, the set of model constraints that gradually increases the fraction of coal-burning capacity that can be converted to burn low-sulfur, low-Btu subbituminous coal in a given year was changed from the *AEO2001* version to eliminate the constraint by 2003. The two changes were made because accelerated and more stringent emission restrictions are assumed to be likely to constitute sufficient justification to end contracts under *force majeure* provisions. The changes also provide the necessary economic incentive to install, on short notice, modifications to many power plants that will permit the burning of coal blends containing substantial fractions of cheaper subbituminous coal.

Renewable Fuels Module

The Renewable Fuels Module (RFM) consists of five submodules that represent the major nonhydroelectric renewable energy resources—biomass, landfill gas, solar (thermal and photovoltaic), wind, and geothermal energy. The RFM defines technology construction and operating costs, fuel resource volumes and prices (biomass, landfill gas, and geothermal), and 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 hydroelectric (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. In addition to building new biomass plants, the EMM also allows coal-fired power plants to use biomass (wood and waste products) along with coal, a process referred to as “co-firing.” 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. In addition, because the trees and plants that become biomass consume CO_2 during their growth, their net emissions are assumed to be zero.

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, forestry residues, and urban wood waste / mill residues. Because of recent legislative changes, this analysis (as in *AEO2001*) assumes an extension of the production tax credit under the Energy Policy Act of 1992 from December 31, 1999, through December 31, 2001, granting tax-paying entities that build new wind or closed-loop biomass facilities a tax credit of 1.7 cents per kilowatthour for the first 10 years of electricity generation from qualifying facilities.

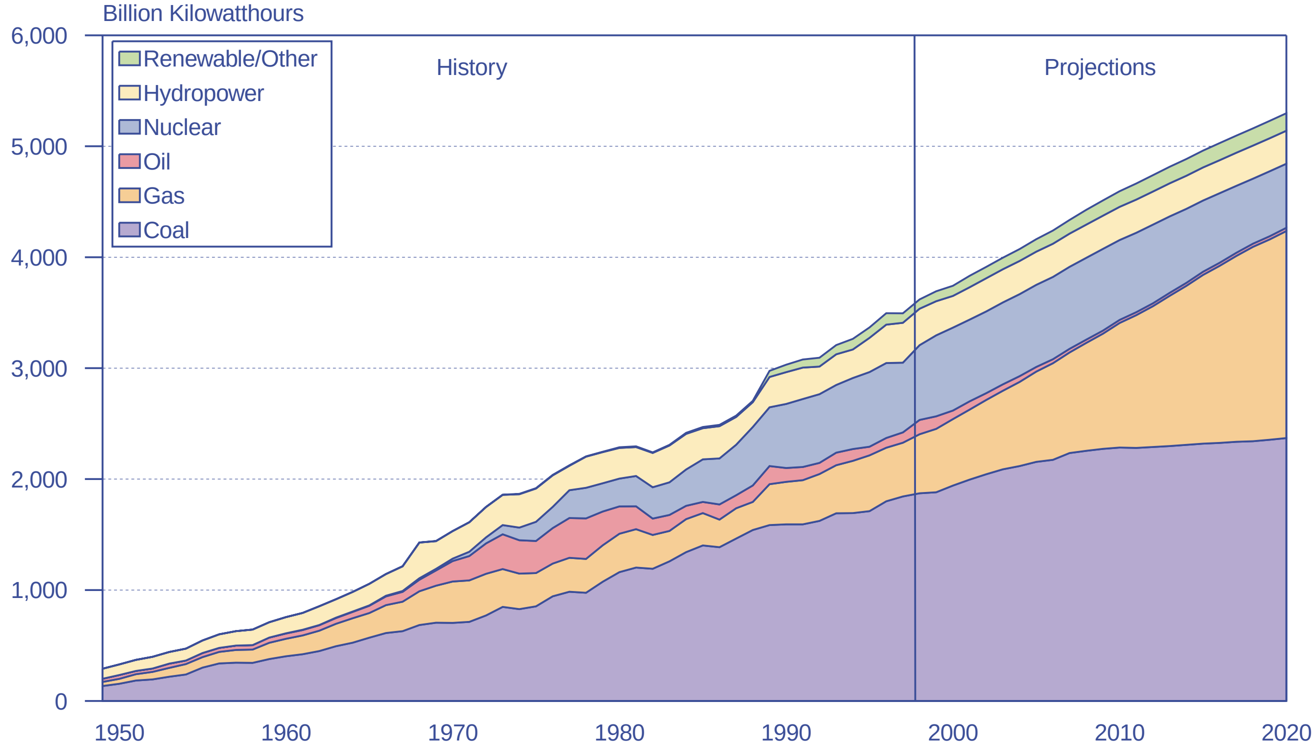
3. Electricity Market Impacts

Introduction

For the last 100 years, electricity production in the United States has been dominated by 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 2). 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 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 for a quarter century, and many previous orders have been canceled. 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. Although few new coal plants are expected to be added, existing coal plants are projected to be used more heavily as demand for electricity grows. Natural gas is expected to be the dominant fuel when new plants are needed. New natural-gas-fired combustion turbines and combined-cycle plants are the most economical options for most uses. New natural-gas-fired combined-cycle plants cost approximately half as much to build as new coal plants, are substantially more efficient, and have much lower emissions. These factors generally offset the higher fuel cost for natural gas. 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 forecast, and no new nuclear plants are forecast for the United States through 2020.

Figure 2. Electricity Generation by Fuel, 1949-1998, and Projections for the Reference Case, 1999-2020



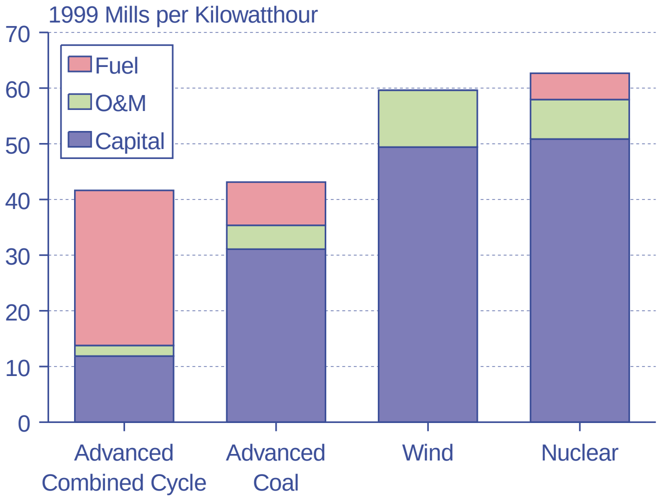
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run MCBASE.D121300A.

In the NEMS projections, the imposition of the NO_x, SO_2, and, especially, the CO_2 emission caps analyzed in this report has impacts on all aspects of the electricity generation business. The emission caps affect capacity planning and plant retirement decisions, investments in emission control equipment, fuel choices for generation, electricity supply sector costs, and consumer prices. In turn, the change in electricity prices causes consumers to alter their electricity use by buying more efficient appliances, switching to other fuels, or generating their own electricity. This chapter discusses these issues together with the potential impact on total CO_2 emissions and key uncertainties in the projections.

Capacity Planning

In the reference case for the analysis, more than 410 gigawatts of new capacity (roughly 1,367 new 300-megawatt plants) is projected to be needed to meet the growing demand for electricity over the next 20 years and to replace 63 gigawatts of retiring power plants. The vast majority, approximately 92 percent, of the new capacity added is projected to be natural-gas-fired combustion turbines and combined-cycle facilities,[12] because their low construction costs and relatively high efficiencies make them economical for most uses. In terms of levelized costs—the costs of building and operating a new plant throughout its life—these plants are less expensive than other options for most uses (Figure 3). Other factors, such as their relatively small, modular size, low initial capital costs and low emission rates, also make them attractive.

Figure 3. Reference Case Projections of Levelized Costs for New Power Plants, 2005



Source: National Energy Modeling System, run MCBASE. D121300A.

New coal-fired plants can be economical when new plants are needed to serve continuous (baseload) needs, or when the difference between coal and natural gas prices delivered to power plants widens beyond $2.50 or so per million Btu. In the reference case this is projected to occur early in the forecast period, before gas prices begin declining from their current levels, and later in the projections, as increasing natural gas use leads to higher gas prices. For new renewable technologies, costs generally are projected to remain higher than those for coal and gas plants. Although costs have declined for wind, biomass, and solar generation technologies over the past 20 years, they still are not expected to be broadly competitive with new gas-fired plants for major capacity additions, absent subsidies or other support of some kind.

In the analysis cases, the dominant role of new gas-fired plants is projected to continue with the imposition of NO_x, SO_2, and CO_2 emission caps; however, the projections suggest that the caps would alter the economics of operating existing coal plants. Although coal plants are the major emitters of CO_2, SO_2, and NO_x in the power sector, they are very economical to operate. Producing some of the least expensive power available, the vast majority are projected to continue operating through 2020 in the reference case. When tighter emission regulations are assumed, however, operating and retirement decisions for the coal-fired plants now in operation are expected to change. Owners of the facilities will have to decide whether to pay the costs for emission allowances and fees, invest in new emission control equipment, or retire the facilities.

In the reference case, relatively few coal plants—10 gigawatts of capacity (just over 3 percent of total existing coal-fired capacity in 1999)—are projected to be retired (Table 6). In response to NO_x emission caps alone, whether imposed in 2005 or 2008, coal plant retirements are expected to be nearly the same as in the reference case. The primary compliance options to meet the NO_x emission caps are adding SNCR and SCR emission control equipment. In the reference case, SNCR and SCR controls are expected to be added to nearly 128 gigawatts of capacity to comply with the 19-State summer season NO_x cap beginning in 2004 (Table 7). In the 2005 and 2008 NO_x cap cases, however, more than twice that capacity—between 303 and 311 gigawatts—is projected to have one or the other post-combustion emission control technology added.

SNCR and SCR equipment can be expensive to add, especially to smaller plants that are used infrequently; but for many plants the projections indicate that it would be more economical to add the emission controls than to replace the plants. The EPA estimates used in

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[12] See Appendixes A-I for detailed tables of the results for each of the cases.

Table 6. Projected Coal Plant Retirements, 2005-2020
(Cumulative Gigawatts of Capacity Retired After 1998)

Analysis Case	1999-2005	1999-2008	1999-2010	1999-2015	1999-2020
Reference	7	9	9	10	10
SO_2 Cap Cases					
SO_2 2005	9	10	10	11	11
SO_2 2008	8	9	9	10	11
SO_2 Sensitivity	9	10	10	11	11
CO_2 Cap Cases					
CO_2 1990-7% 2005	9	23	45	63	66
CO_2 1990-7% 2008	8	16	37	67	70
CO_2 Sensitivity	8	15	22	33	40
Integrated Cases					
Integrated 2005	7	20	41	58	66
Integrated 1990-7% 2005	8	22	47	73	79
Integrated 2008	7	16	35	62	68
Integrated 1990-7% 2008	7	17	42	85	90
Integrated Sensitivity	9	17	26	37	44

Source: National Energy Modeling System, runs MCBASE.D121300A (reference), MCNOX05.D121300A (NO_x 2005), MCNOX08.D121300A (NO_x 2008), MCSO205.D121300A (SO_2 2005), MCSO208.D121300A (SO_2 2008), MCSO205H.D121300A (SO_2 sensitivity), FDC7B05.D121300A (CO_2 1990-7% 2005), FDC7B08.D121300A (CO_2 1990-7% 2008), FDC7B05H.D121300A (CO_2 sensitivity), FDPOL05.D121300A (integrated 2005), FDP7B05. D121300B (integrated 1990-7% 2005), FDPOL08.D121500A (integrated 2008), FDP7B08.D121500A (integrated 1990-7% 2008), and FDP7B05H. D121300A (integrated sensitivity).

Table 7. Projected Additions of Power Plant Emission Controls, 1999-2020
(Gigawatts)

Analysis Case	Emission Control Technology		
	SNCR	SCR	FGD
Reference	39	90	15
NO_x Cap Cases			
NO_x 2005	59	252	14
NO_x 2008	60	243	15
SO_2 Cap Cases			
SO_2 2005	32	117	128
SO_2 2008	27	124	130
SO_2 Sensitivity	36	96	52
CO_2 Cap Cases			
CO_2 1990-7% 2005	16	42	0
CO_2 1990-7% 2008	22	54	0
CO_2 Sensitivity	26	54	0
Integrated Cases			
Integrated 2005	56	157	21
Integrated 1990-7% 2005	49	147	17
Integrated 2008	48	123	23
Integrated 1990-7% 2008	38	108	18
Integrated Sensitivity	26	60	8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction. FGD = flue gas desulfurization (scrubbers).

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

this analysis show that adding SCR equipment to a 200-megawatt coal plant would cost approximately $72 per kilowatt and reduce NO_x emissions by between 70 and 80 percent.[13] Because only a few more coal plants are expected to be retired in these cases than in the reference case, there is little change in the projections for natural-gas-fired generation.

The primary options for reducing SO_2 emissions at coal plants are switching to lower sulfur coal, adding flue gas desulfurization (FGD) equipment (scrubbers), or retiring plants. In the reference case, to comply with the CAAA90 phase II emission cap, switching coal and adding scrubbers both play important roles. Scrubbers are expected to be added to approximately 15 gigawatts of

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[13] U.S. Environmental Protection Agency, *Analyzing Electric Power Generators Under CAAA*, web site www.epa.gov.

capacity through 2020, while the share of coal consumption coming from lower sulfur western mines is projected to grow from 44 percent in 1999 to 58 percent in 2020. The price of SO_2 emission allowances is projected to be $170 per ton in 2010 and $246 per ton in 2020 in the reference case.

The requirements for tighter emission controls in the SO_2 cap cases are projected to lead to a slight increase in the number of coal plant retirements and an increase in scrubber additions among remaining coal plants. The 3,273,000-ton annual cap in the SO_2 cap cases would be difficult to meet primarily through switching to low-sulfur coal. Assuming that coal plants were to continue to operate as they do in the reference case, the 8,950,000-ton CAAA90 cap implies an average emission rate at coal plants of 0.8 pounds per million Btu—an average rate that can be achieved by scrubbing some plants and switching others to low-sulfur coal. Using the same assumptions, the 3,273,000-ton cap implies an average rate of approximately 0.3 pounds per million Btu—a rate that would be difficult to meet at most plants without adding scrubbers.

The 3,273,000-ton emission cap assumed in the SO_2 cap cases is not projected to be met until well after the effective dates of the caps, because it is assumed that power plant owners would be able to use any allowances they had accumulated through 1999. For this analysis it was assumed that the banked allowances would be used by 2015. As a result, the cap would not be fully binding until 2016 in the SO_2 cap cases. Because of the stringent cap in the SO_2 cases, between 128 and 130 gigawatts of capacity is projected to add scrubbers (Table 7). As in other cases, natural-gas-fired plants are expected to remain the most economical option when new plants are needed. As a result, projected additions of renewable plants are the same in the SO_2 cap cases and the reference case.

The expected SO_2 allowance prices in the SO_2 cap cases are much higher than those in the reference case (Figure 4). The initial response to the more stringent SO_2 cap is expected to include adding scrubbers to larger coal plants; retiring older, smaller coal plants; and adding new natural gas combined-cycle plants to replace them.

The projections for SO_2 allowance prices are sensitive to the variation in the assumed SO_2 emission target. The SO_2 allowance prices are projected to reach $735 per ton in 2010 in the SO_2 2005 case and $300 per ton in the SO_2 sensitivity case (Figure 5). Under the less stringent emission target assumed in the SO_2 sensitivity case, the expected need to add emission controls and switch to lower sulfur coals is significantly reduced.

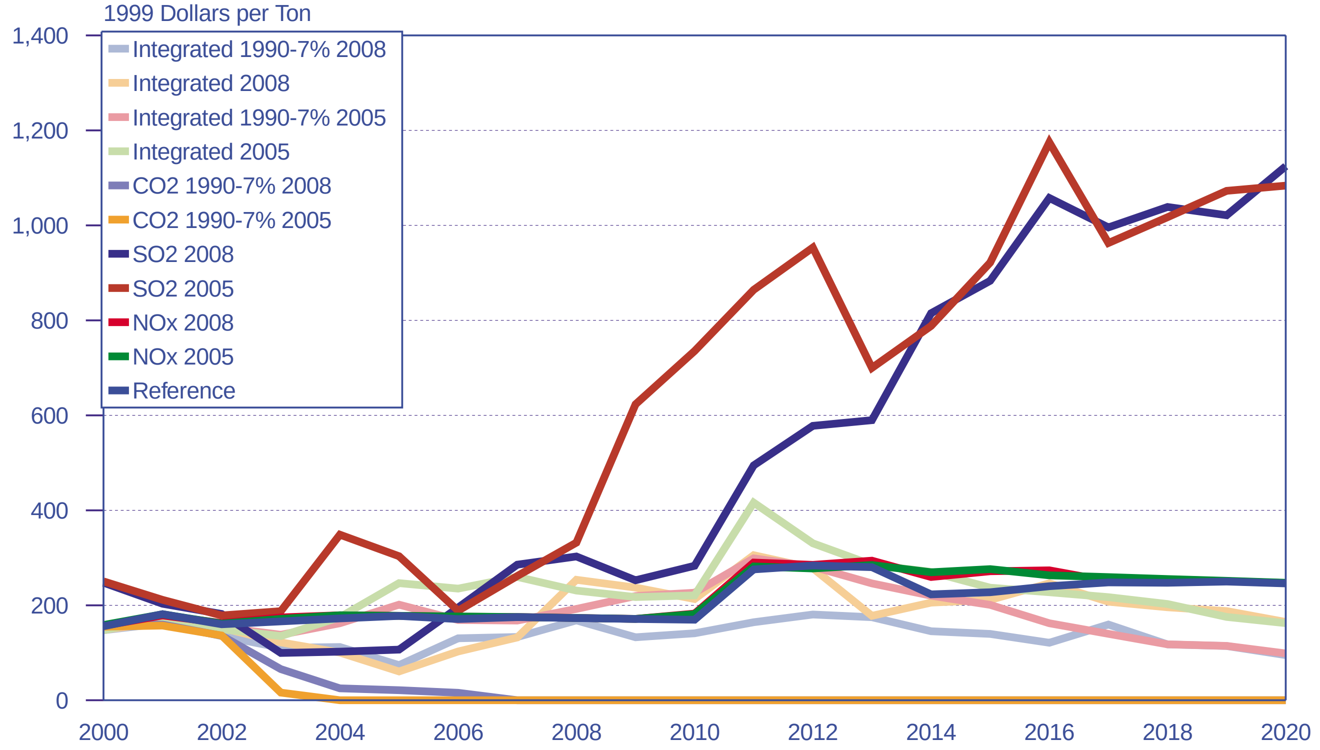
The amount of emission control equipment projected to be needed in the NO_x and SO_2 cap cases, particularly those with 2005 compliance dates, could cause system operational problems under some conditions. Typically, when new emissions controls are added, particularly SCRs, a plant must be off line for a time so that final connections can be made. Several recent studies have looked into whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the NO_x SIP call might lead to system operational and reliability problems. 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 work on their plants, and the interconnection time needed for each plant.

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 approach 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 grows more rapidly than expected over the next few years and/or delays occur in the siting and permitting of needed new plants, the additional requirement of adding a large amount of emission control equipment could exacerbate a tight market situation, leading to larger near-term price impacts than are shown in this analysis.

In the CO_2 cap cases, carbon allowance fees are expected to make it uneconomical to continue operating a large number of existing coal plants. In addition, no new coal plants are expected to be added. Unlike the NO_x and SO_2 cap cases, the CO_2 cap cases project that power plant operators would not be able to use emission control technologies to meet the assumed cap, at least not in the time horizon of this analysis. Instead they are expected to have to reduce their reliance on coal significantly and turn to lower carbon fuels, primarily natural gas. By 2020, between 66 and 70 gigawatts (22 to 23 percent) of existing coal plants are projected to be retired to comply with the CO_2 caps. The need for new NO_x and SO_2 emission control equipment is projected to be much lower in the integrated sensitivity case, because the CO_2 cap causes enough switching from coal to gas to allow the electricity generation sector to meet the assumed annual NO_x and SO_2 caps without adding much additional emission control equipment.

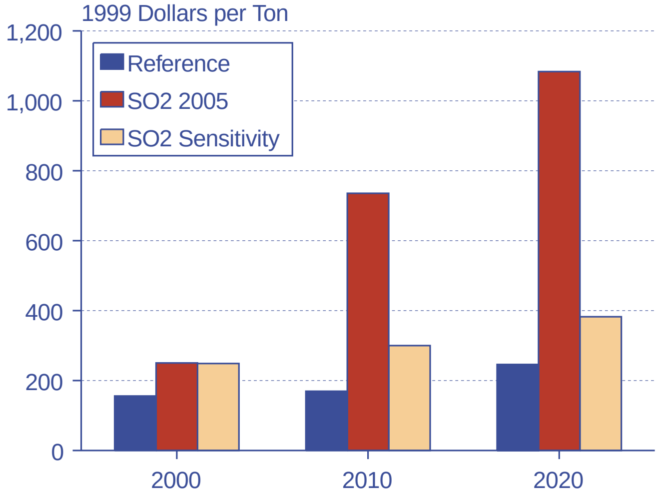
Carbon allowance fees in the CO_2 cap cases are projected to range from $139 and $143 per metric ton carbon equivalent in 2010 to $139 and $141 in 2020 (Figure 6). The integrated cases that set the carbon cap at 7 percent below the 1990 level produce the largest number of projected coal plant retirements and the largest projected increases in investments in new gas and renewable plants. The carbon allowance fee, which is assumed to be added to the electricity production price of all

Figure 4. Projected SO_2 Allowance Prices, 2000-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 5. Projected SO_2 Allowance Prices, 2000, 2010, and 2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCSO205.D121300A, and MCSO205H.D121300A.

fossil-fired plants in proportion to the carbon content of their fuels, makes relatively low-carbon natural gas and carbon-free renewable and nuclear technologies more economically attractive than coal or oil facilities. It also makes maintaining existing nuclear plants more attractive than in the reference case. Relative to the reference case, between 49 and 66 gigawatts more gas-fired capacity and 34 to 38 gigawatts more renewable capacity are projected to be added,[14] and 12 to 17 gigawatts less nuclear capacity is projected to be retired.

In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 cap is projected to lead to carbon allowance fees that are lower than those projected in the comparable CO_2 1990-7% 2005 and integrated 1990-7% 2005 cases. In 2010, the carbon allowance fees projected in the CO_2 sensitivity case are between $37 and $41 per metric ton carbon equivalent less than those projected in the comparable cases with the more stringent CO_2 caps. A large amount of new gas-fired capacity is still expected to be needed in these cases to meet the caps, but the amount of renewable capacity added—above the level projected in the reference case—is much less than projected in the cases with more stringent CO_2 caps. The relative economics of new renewable capacity are sensitive to the projected carbon allowance fees. In the CO_2 sensitivity and integrated sensitivity cases, between 16 and 18 gigawatts more new renewable capacity is projected to be built than in the reference case.

The results in the integrated cases essentially mirror those of the CO_2 cap cases; the magnitude of the projected changes in power plant operations to comply

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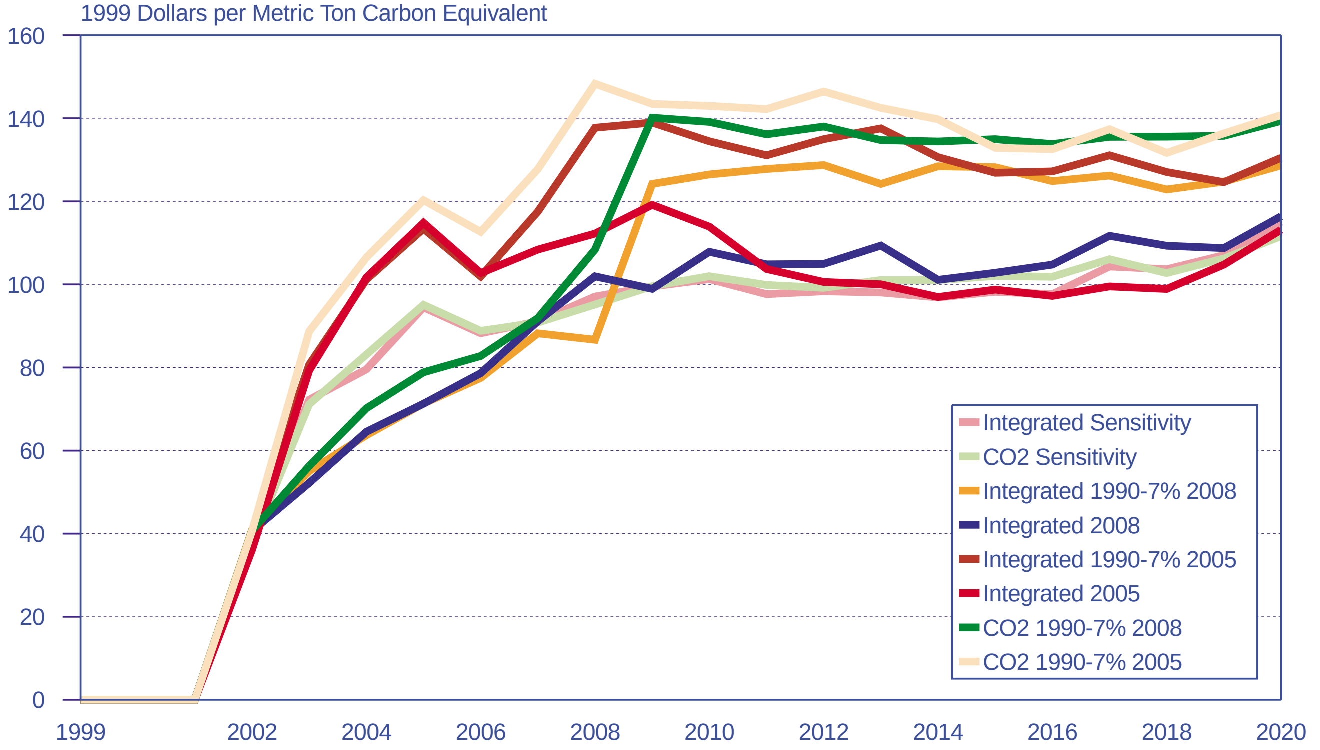
[14] See Chapter 4 for a discussion of the specific renewables projected to be added.

Figure 6. Projected Carbon Fees, 1999-2020

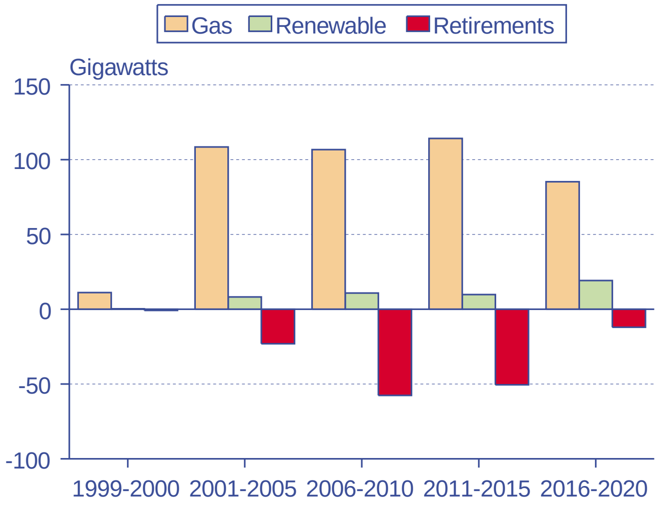


Source: National Energy Modeling System, runs FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

with the CO_2 cap generally overwhelms the projected impacts of the NO_x and SO_2 caps. New natural gas plants and, to a lesser extent, renewable plants are projected to be added to meet the growing demand for electricity and to replace retiring coal plants (Figure 7). The need for new capacity in the integrated cases, especially those with the 1990-7% CO_2 cap, is projected to require rapid construction of new plants. Almost 129 gigawatts of new capacity is projected to be needed in the integrated 1990-7% 2005 case by 2005. That rate of construction— averaging 21 gigawatts per year—would be more than double the rate of construction of new generating plants during the 1990s, which averaged only 7 gigawatts per year, and 26 percent above the level expected in the reference case.

Construction rates higher than 20 gigawatts per year were last seen in the 1980s, indicating that such construction levels are achievable. Figure 8 superimposes annual capacity additions for the period 1965 to 1985 on the projected additions from 2000 through 2020 in the integrated 1990-7% 2005 case, showing that the amount of new capacity projected to be needed in this case would be near the record levels seen in the past. This would be a difficult challenge to meet in a short time period. Combining the CO_2 cap with the NO_x and SO_2 caps is expected to reduce the need to add SNCR, SCR, and FGD equipment to reduce emissions from existing plants (Table 7), because so many coal plants are projected to be retired to meet the CO_2 cap.

Figure 7. Projected Capacity Additions by Fuel and Projected Retirements in the Integrated 1990-7% 2005 Case, 1999-2020



Source: National Energy Modeling System, run FDP7B05.D121300B.

The degree to which the CO_2 cap overwhelms the impacts of the other caps can be seen in the projections of NO_x and SO_2 emissions in the CO_2 cap cases (which assume no additional restrictions on NO_x and SO_2 emissions beyond those assumed in the reference case) (Table 8). In the CO_2 1990-7% 2005 case, power sector NO_x emissions in 2010 are projected to be 41 percent below their projected level in the reference case and within 0.9

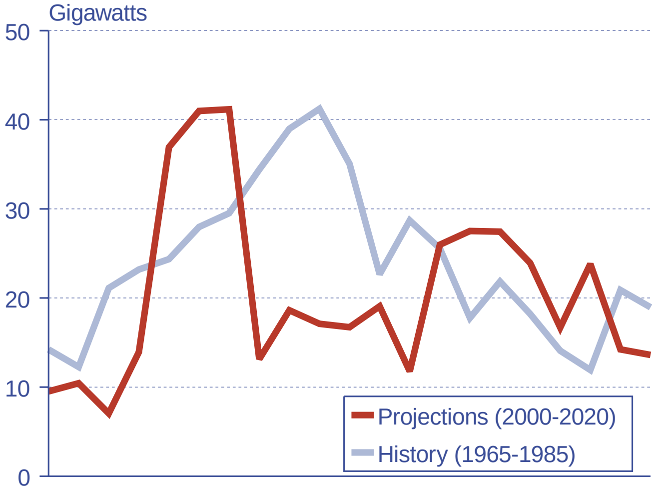
million tons of the more stringent NO_x cap. Similarly, SO_2 emissions in 2010 in the CO_2 1990-7% 2005 cap case are projected to be 17 percent below their projected level in the reference case.

As in the CO_2 cap cases, fewer nuclear power plants are projected to be retired in the integrated cases than in the reference case. Approximately 26 gigawatts (27 percent) of existing nuclear capacity is projected to be retired in the reference case, because it is expected that it will become less expensive to replace aging nuclear plants than to maintain them. In the CO_2 cap and integrated cases, however, the combination of carbon allowance fees and higher natural gas prices is projected to make replacing nuclear plants with coal or gas plants more expensive. As a result, fewer are expected to be retired. Total operating nuclear capacity in 2020 is projected to range between 84 and 89 gigawatts in the CO_2 cap and integrated cases, as compared with 72 gigawatts in the reference case and 97 gigawatts today.

In both the CO_2 cap and integrated cases, cogeneration and distributed generation capacity (in buildings) are projected to increase above the levels projected in the reference case. This analysis assumes that the proposed emission caps would not apply to cogeneration and distributed technologies located at customer sites. As a result, when the projected price of power from the grid increases, the economics of building on-site cogeneration or distributed generation facilities improve. In the reference case, cogeneration and distributed generation capacity additions are projected to total 19 gigawatts between 1999 and 2020. In the CO_2 cap cases the 2020 level is projected to be as much as 47 gigawatts higher. Similar changes from the reference case are projected in the integrated cases.

The vast majority of the cogeneration and distributed generation facilities projected to be built by 2020 in the CO_2 cap and integrated cases are expected to be fueled by natural gas, despite projections of higher gas prices in these cases than in the reference case as a result of projected increases in natural gas use for central station

Figure 8. Projected Annual Capacity Additions in the Integrated 1990-7% 2005 Case, 2000-2020, Compared with Historical Annual Capacity Additions, 1965-1985



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05. D121300B.

Table 8. Projected Emissions from Electric Power Plants, 2010 and 2020

Analysis Case	2010			2020		
	NO_x (Million Tons)	SO_2 (Million Tons)	CO_2 (Million Metric Tons Carbon Equivalent)	NO_x (Million Tons)	SO_2 (Million Tons)	CO_2 (Million Metric Tons Carbon Equivalent)
Reference	4.20	9.70	686	4.37	8.95	776
NO_x Cap Cases						
NO_x 2005	1.55	9.70	677	1.60	8.95	769
NO_x 2008	1.55	9.70	678	1.59	8.95	768
SO_2 Cap Cases						
SO_2 2005	4.04	3.67	676	4.25	3.27	776
SO_2 2008	4.16	4.12	688	4.28	3.27	781
CO_2 Cap Cases						
CO_2 1990-7% 2005	2.47	8.09	437	2.01	6.68	439
CO_2 1990-7% 2008	2.33	7.77	430	1.95	6.61	441
Integrated Cases						
Integrated 2005	1.37	4.22	474	1.18	3.27	477
Integrated 1990-7% 2005	1.30	3.92	443	1.12	3.27	440
Integrated 2008	1.42	4.52	476	1.22	3.27	477
Integrated 1990-7% 2008	1.32	4.02	430	1.16	3.27	440

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

electricity generation. For industrial cogeneration systems, combustion turbines burning natural gas are expected to be the preferred technology, although some systems currently being installed will use petroleum distillate fuels or byproduct gases from refining or chemical processes.

A number of factors make it unlikely that new coal-fired cogeneration systems will be built. For example, on a purely economic basis, the capital cost of new coal systems is significantly more than the cost of modern turbine-based natural gas systems—in many cases, more than twice as much. In addition, although fuel costs are higher, turbine-based systems cost less to operate and maintain than comparably sized coal plants. From a technical perspective, coal systems are appropriate only for a small portion of industrial facilities. Because coal systems use boilers and steam turbines, they generally have a power to heat ratio less than 0.5, which means that coal-fired generators can only be used at sites with high thermal loads. In addition, these boiler / steam turbine systems do not benefit from economies of scale at sizes below 40 megawatts, which restricts their market to larger industrial facilities. In contrast, combustion turbines can be cost-effective in systems as small as 1 megawatt, and they can be configured with power to heat ratios ranging from 0.5 to 4.0. Current environmental regulations also discourage the use of coal, with most new systems requiring significant secondary pollution abatement technologies to meet the emissions standards in their permits.

Generation by Fuel

The projected fuel mix for electricity generation in the NO_x and SO_2 cap cases (including the SO_2 sensitivity case) is not very different from that in the reference case. In the SO_2 cap cases slightly less coal-fired generation is expected (generally 1 to 2 percent less in 2020) and slightly more gas generation, because existing gas plants are projected to be used more intensively and new gas plants are projected to be added to replace the small number of coal plants that are expected to be retired.

In contrast, the projected shift from coal to natural gas and renewables is much larger in the CO_2 cap and integrated cases. Natural-gas-fired generation is projected to be much higher in the cases with CO_2 caps than in the reference case (Table 9). In the reference case, the share of generation coming from natural gas is projected to increase from 15 percent in 1999 to 20 percent in 2005, 24 percent in 2010, and 35 percent in 2020. In the integrated 1990-7% 2005 case, however, the projected natural gas shares are 34 percent in 2005, 43 percent in 2010, and 55 percent in 2020 (Figure 9). Because of the relatively high carbon content of coal—more than 70 percent higher per Btu than natural gas—the projected market-based carbon allowance fee would make it uneconomical to continue operating many coal plants. In addition, coal plants that are not retired are expected to be operated less intensively than in the reference case. The projected share of generation for coal-fired power plants in the integrated 1990-7% 2005 case is less than 17 percent in 2020, compared with 45 percent in the reference case.

Although the impact of power sector Hg emissions caps is not addressed in this report, the projected reduction in coal use in the CO_2 cap and integrated cases is expected to lead to lower mercury emissions. It is estimated that coal-fired power plants in the United States currently produce approximately 50 tons of Hg emissions per year, approximately one-third of total U.S. Hg emissions. Generation from other fuels produces much lower Hg emissions. With coal-fired generation projected to increase by 26 percent between 1999 and 2020 in the reference case, Hg emissions are projected to grow over time absent restrictions; however, the CO_2 cap and integrated cases are projected to lead to significant reductions in the use of coal and, hence, Hg emissions. In the most stringent case, the integrated 1990-7% 2005 case, coal-fired generation is projected to be 64 percent below the reference case level in 2020. Although the associated decline in Hg emissions would depend on the specific coal plants that continued generating, in percentage terms it could be similar to the change in coal-fired generation. As mentioned above, constraints on Hg emission will be examined in a later report.

Renewables are also projected to account for a much larger share of generation in the CO_2 cap and integrated cases than in the other cases (Table 10). Because renewable fuels produce virtually no NO_x, SO_2, or CO_2 emissions, their operating costs would not be affected by emission fees. As a result, they are expected to become more economical relative to fossil-based alternatives in the emission cap cases. In the reference case, because hydroelectric generation is expected to stay near today's level, the share of generation accounted for by renewable fuels is projected to change very little, falling slightly from 11 percent in 1999 to 8 percent in 2020. Generation from nonhydroelectric renewables is expected to grow, but not enough to increase the overall share from renewables.

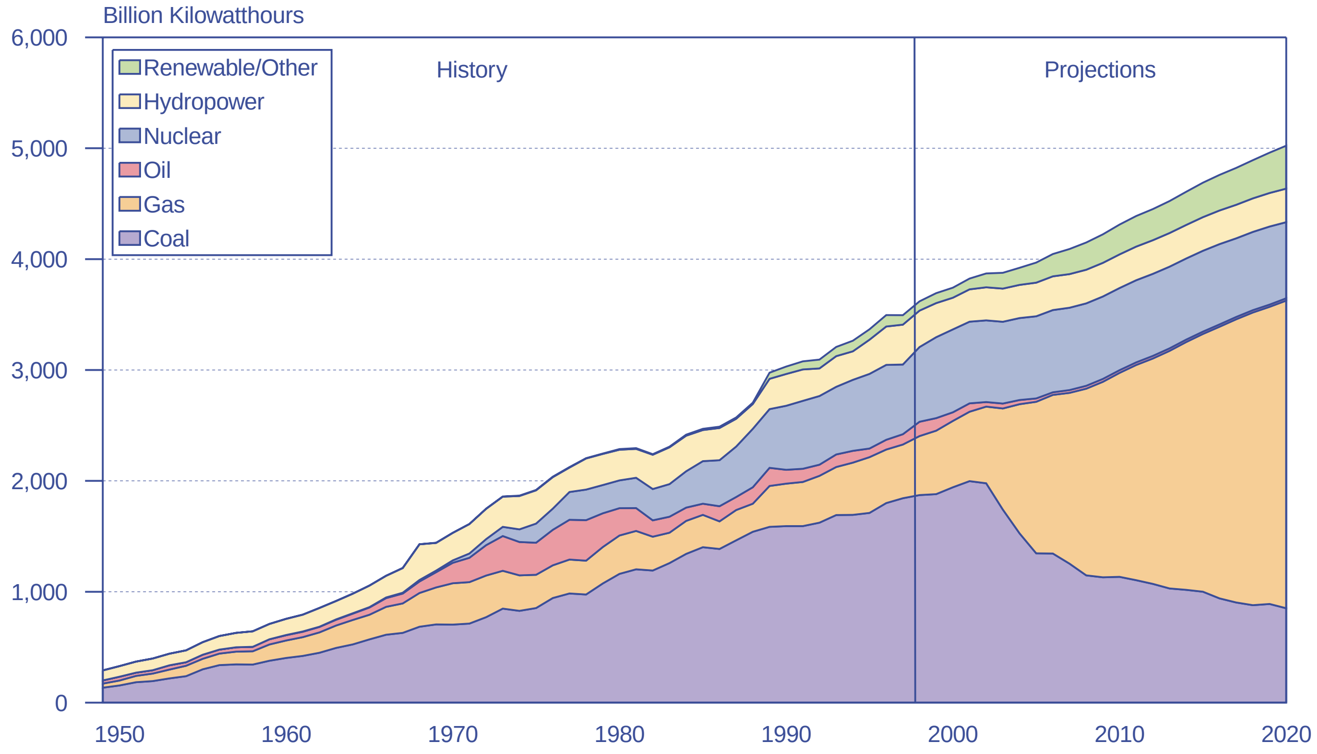
In the CO_2 cap and integrated cases, generation from renewables is expected to be much higher than projected in the reference case. The share of total generation coming from renewable facilities is projected to be as high as 14 percent in 2020 in the CO_2 1990-7% 2005 case. As discussed in Chapter 4, the projected level of renewable energy development, especially for nonhydroelectric renewables, in the CO_2 cap and integrated cases would be unprecedented in the United States and would require significant growth in the manufacturing and construction firms associated with renewable technologies.

Table 9. Projected Electricity Generation from Natural-Gas-Fired Power Plants, 2005-2020
(Billion Kilowatthours)

Analysis Case	2005	2008	2010	2015	2020
Reference	813	973	1,123	1,521	1,866
NO_x Cap Cases					
NO_x 2005	819	1,000	1,161	1,552	1,894
NO_x 2008	828	1,003	1,164	1,560	1,902
SO_2 Cap Cases					
SO_2 2005	816	1,015	1,195	1,574	1,911
SO_2 2008	801	1,003	1,146	1,570	1,901
CO_2 Cap Cases					
CO_2 1990-7% 2005	1,339	1,666	1,859	2,304	2,704
CO_2 1990-7% 2008	1,083	1,560	1,922	2,344	2,748
Integrated Cases					
Integrated 2005	1,369	1,525	1,746	2,301	2,752
Integrated 1990-7% 2005	1,367	1,683	1,839	2,324	2,774
Integrated 2008	1,060	1,615	1,789	2,309	2,746
Integrated 1990-7% 2008	1,098	1,590	1,935	2,365	2,816

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 9. Electricity Generation by Fuel, 1949-1998, and Projections for the Integrated 1990-7% 2005 Case, 1999-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05.D121300B.

As with renewable capacity, the projections for renewable generation are sensitive to the assumed stringency of the CO_2 cap and the resulting carbon allowance fee. With the less stringent CO_2 cap assumed in the CO_2 sensitivity and integrated sensitivity cases, renewable generation is not projected to grow nearly as much from the reference case projections as it does in the comparable CO_2 cap and integrated cases. For example, in the CO_2 1990-7% 2005 case, generation from renewable facilities is projected to reach 712 billion kilowatthours in 2020—269 billion kilowatthours (61 percent) above the level expected in the reference case. In both the CO_2 sensitivity and integrated sensitivity cases, however, renewable generation is projected to reach between 586

Table 10. Projected Electricity Generation from Renewable Fuels, 2005-2020
(Billion Kilowatthours)

Analysis Case	2005	2008	2010	2015	2020
Reference	401	421	429	438	443
CO_2 Cap Cases					
CO_2 1990-7% 2005	477	542	574	620	712
CO_2 1990-7% 2008	483	551	581	610	679
CO_2 Sensitivity	481	539	559	563	595
Integrated Cases					
Integrated 2005	475	541	559	570	608
Integrated 1990-7% 2005	474	538	561	602	677
Integrated 2008	481	532	553	561	607
Integrated 1990-7% 2008	482	540	562	588	658
Integrated Sensitivity	479	532	553	558	586

Source: National Energy Modeling System, runs MCBASE.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

and 595 billion kilowatthours—143 to 152 billion kilowatthours (32 to 34 percent) above the reference case projection.

Electricity Costs and Consumer Prices

The addition of emission control equipment projected in the analysis cases, combined with the projected shift from coal to natural gas and renewables to comply with the emission caps, and the resultant emission allowance prices, has an impact on the costs faced by power suppliers and the electricity prices faced by consumers (Figure 10). In turn, the changes in prices lead consumers to alter their energy usage decisions, both for electricity and other fuels.

In the NO_x cap cases it is projected that $17 billion would be spent by power plant operators between 1999 and 2020 for new emission control equipment. These costs represent $7 billion above the projected expenditures in the reference case to comply with the NO_x SIP Call. Given that the 1998 net book value for plant investments for investor-owned utilities is over $363 billion, the projected costs are not large. Additional costs—in the form of lost revenue—would be faced by power plant operators who are projected to retire currently profitable plants rather than face the costs of upgrading them.

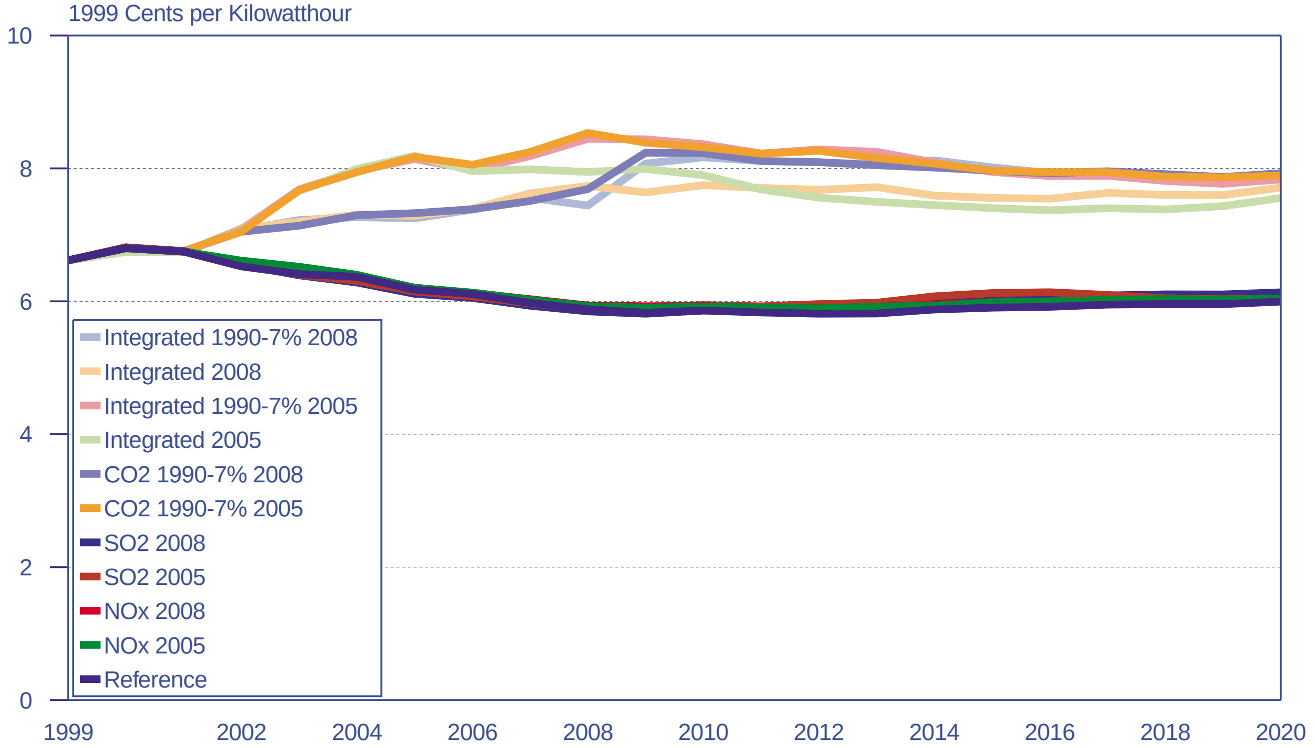
The increased costs for power plant operators, if incurred in generation markets with cost-of-service regulation, would be passed on directly to consumers in electricity prices. In competitively priced markets, however, the higher costs would be passed on to consumers only if they increased the operating costs of the generating plants that set the market price for power. For example, if SCR equipment were added to reduce NO_x emissions from a coal plant that did not set the market price for power, the costs of installing and operating the equipment would not be passed on to consumers as long as the plant's operating costs remained below the market price. In effect, the net profit from the plant would be reduced. Conversely, a plant with relatively low NO_x emissions that does not set the market price could see higher profits in these cases.

In the NO_x cap cases, a portion of the projected increase in electricity generation costs would fall on plants not setting the market price for power. In the NO_x 2005 case, the difference between the costs incurred and the increased revenue to power plant operators is projected to average $1.0 billion per year between 2005 and 2020 (Figure 11). The overall impact on electricity prices, however, is projected to be small. The price of electricity in 2010 is projected to be 1 percent higher than in the reference case.

In the SO_2 cap cases, as in the NO_x cap cases, the projected total investment in new emission control equipment would not be large relative to the $363 billion net plant investment for investor-owned utilities in 1998. Higher projected SO_2 allowance prices and greater dependence on natural gas would lead to higher generation costs and higher electricity prices. However, also as in the NO_x cap cases, a portion of the projected increase in generation costs would fall on plants not setting the market price for electricity (and a large part of the costs are fixed capital costs that do not affect operating costs), and therefore the full costs of investments in emission control equipment would not be passed on to consumers in electricity prices. The price of electricity in the SO_2 2005 case is projected to be roughly 1 percent above the reference case projection in 2010 and between 1 and 2 percent higher in 2020. Again, as in the NO_x cap cases, plants with low or no SO_2 emissions would see increased profits in these cases.

The impact on electricity prices is projected to be much larger in the CO_2 cap and integrated cases than in the NO_x and SO_2 cap cases, because there are currently no commercially available technologies for removing and storing (sequestering) CO_2. The only ways to make large

Figure 10. Projected Electricity Prices, 1999-2020

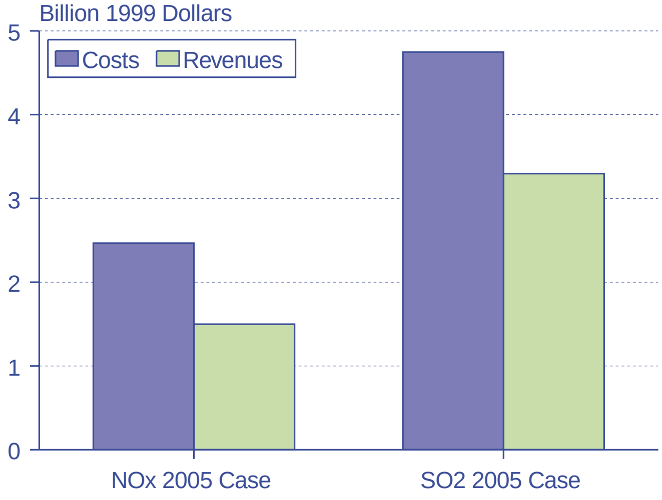


Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

reductions in CO_2 emissions are to reduce the consumption of fuels with relatively high carbon content or to increase the efficiency of electricity production and consumption. In addition, the CO_2 allowance price (throughout this report given in dollars per metric ton carbon equivalent) falls on all fossil fuel generators, those using coal, oil, and natural gas. Unlike in the NO_x and SO_2 cases, because all fossil plants are affected, the operating costs for plants setting the electricity market price are expected to increase, and consumer electricity prices are expected to increase with them. In these cases, owners of existing non-fossil-fuel plants—nuclear, hydroelectric, and other renewables—would see higher profits as market prices increased because of the CO_2 allowance price. The owners of relatively low carbon fossil plants, such as very efficient natural gas plants, could also benefit to a lesser degree.

Across the CO_2 cap and integrated cases, the price of electricity is projected to range from 17 percent to 33 percent higher than the reference case projection in 2005. Because the assumed compliance dates are less than 10 years away, markets would not have much time to adjust and take advantage of normal capital turnover. As a result, the largest differences in projected electricity prices relative to the reference case generally are seen from 2005 to 2009. In the later years of the projections, when new gas-fired and renewable generation facilities are expected to be in operation, the projected differences from the reference case are smaller. By 2020, prices in the CO_2 cap and integrated cases are projected to be between 26 and 32 percent higher than projected in the reference case. Because of the higher prices expected in the CO_2 cap cases and integrated cases, electricity consumers are projected to reduce their consumption of electricity by 5.5 to 7.5 percent on average relative to the reference case over the 2005 to 2020 time period.

Figure 11. Projected Average Annual Changes from Reference Case Power Plant Costs and Revenues in the SO_2 and NO_x 2005 Cap Cases, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, and MCSO205.D121300A.

In each of the analysis cases, particularly the cases with CO_2 emission caps, the total impacts on electricity prices reflect both the change in resource costs (higher fuel and operating and maintenance costs) and the allowance costs on unabated emissions to the degree that they affect the plants setting the price for power. For example, in the integrated 1990-7% 2005 case, CO_2 emission allowance costs represent roughly 69 percent of the change in the total cost of service—all the costs incurred by power suppliers to meet the demand for electricity, including fuel costs, operating and maintenance costs, capital investment costs, and emission allowance costs—in 2010 and 2020.

The allowance prices for NO_x, SO_2, and CO_2 are projected to vary considerably across the analysis cases (Table 11). The differences result from the levels of and interrelationships among the three emission caps in each case. The prices for each emission allowance are inextricably linked, and caution should be used in trying to discern their individual impacts. The linkages among them can be seen by comparing the projections in the reference case and the NO_x, SO_2, and CO_2 cap cases with those in the various integrated cases. For example, NO_x allowances prices in 2010 are projected to be $2,254 per ton in the reference case, $1,081 per ton in the NO_x 2005 case, $2,467 in the SO_2 2005 case, and $0 to $85 per ton in the CO_2 cap and integrated cases (including sensitivity cases).

It may seem surprising that the projected NO_x allowance price is higher in the reference case than in the NO_x cap case with a relatively stringent limit. This occurs because the reference case cap is applied only to plants in 19 States over a 5-month summer season, and, at the margin, it is more expensive to meet than the nationwide annual cap imposed in the NO_x cap cases. The relatively high NO_x allowance prices projected in the SO_2 cap cases also occur partially because of the 19-State, 5-month season cap imposed. These cases assume the same limits that are imposed in the reference case. The NO_x allowance prices in the SO_2 cap cases are slightly higher than those in the reference case, because efforts to meet the stringent SO_2 cap lead to changes in the way particular plants are operated, increasing the cost of NO_x emission reduction options. The low NO_x allowance prices projected in the CO_2 cap and integrated cases, especially in the later years of the forecast, occur because efforts to meet the CO_2 emission caps in these cases lead to substantial reductions in NO_x emissions.

Similar linkages can be seen in the projections of SO_2 allowance prices. The reference, NO_x cap, and CO_2 cap cases all incorporate the CAAA90 8.95 million ton national SO_2 emission cap promulgated. The projected SO_2 allowance prices in the reference and NO_x cap cases are similar. However, when a CO_2 cap is incorporated with the 8.95 million ton SO_2 cap, as in the CO_2 cap cases, efforts expected to be made to meet the CO_2 cap enable

Table 11. Projected Power Plant Emissions Allowance Prices, 2005-2020
(1999 Dollars per Ton and 1999 Dollars per Metric Ton Carbon Equivalent)

	Allowance Prices											
	NO_x				SO_2				CO_2			
Analysis Case	2005	2008	2010	2020	2005	2008	2010	2020	2005	2008	2010	2020
Reference	2,374	1,296	2,254	2,071	178	173	170	246	NA	NA	NA	NA
NO_x Cap Cases												
NO_x 2005	1,196	769	1,081	1,098	178	173	181	247	NA	NA	NA	NA
NO_x 2008	1,102	1,136	1,189	1,225	178	173	182	247	NA	NA	NA	NA
SO_2 Cap Cases												
SO_2 2005	2,419	2,409	2,467	3,164	303	332	735	1,084	NA	NA	NA	NA
SO_2 2008	2,475	1,847	2,320	2,818	107	303	283	1,125	NA	NA	NA	NA
SO_2 Sensitivity	2,484	1,703	2,034	2,104	281	307	300	382	NA	NA	NA	NA
CO_2 Cap Cases												
CO_2 1990-7% 2005	1,981	0	0	0	0	0	0	0	120	148	143	141
CO_2 1990-7% 2008	2,114	0	0	0	21	0	0	0	79	108	139	139
CO_2 Sensitivity	2,191	79	85	0	4	10	5	0	95	95	102	112
Integrated Cases												
Integrated 2005	1,000	141	0	0	247	231	221	162	115	112	114	113
Integrated 1990-7% 2005	969	0	0	0	201	192	226	99	113	138	134	130
Integrated 2008	888	936	0	0	61	254	213	165	71	102	108	116
Integrated 1990-7% 2008	801	876	0	0	74	168	141	95	71	87	126	129
Integrated Sensitivity	2,253	27	64	37	104	103	101	51	94	97	101	115

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

the power sector to meet the SO_2 emissions limits without additional work. As a result, the SO_2 allowance price in these cases falls to zero. The SO_2 cap and integrated cases (excluding the sensitivity cases) incorporate the 3.27 million ton cap examined in this analysis. In the SO_2 cap cases the more stringent standard is projected to lead to much higher SO_2 allowance prices, exceeding $700 per ton in 2010 and $1,100 per ton in 2020. When the 3.27 million ton SO_2 cap is combined with a CO_2 cap in the integrated cases, however, the SO_2 allowance price is expected to range between $141 and $226 per ton in 2010, much lower than in the SO_2 cap cases.

The CO_2 allowance price also varies, but to a smaller degree, when examined with the reference case NO_x and SO_2 provisions than when examined with the more stringent NO_x and SO_2 provisions analyzed in the integrated cases. For example, the CO_2 allowance price (given in dollars per metric ton carbon equivalent) in 2010 in the CO_2 1990-7% 2005 case is projected to be $143; however, in the integrated 1990-7% 2005 case, which incorporates the same CO_2 cap, it is projected to reach only $134 per metric ton. The requirement to also reduce NO_x and SO_2 emissions in the integrated cases slightly reduces the incremental cost of reducing CO_2 emissions.

A coordinated approach to reducing power sector NO_x, SO_2, and CO_2 emissions in the integrated cases should lead to lower overall costs than one for each of the emissions individually. As shown in this report, the compliance decisions that are projected when the NO_x and SO_2 caps are examined alone are very different from those expected when the three emission caps are combined. The exact savings depend on the particular scenarios analyzed. The key factor is the timing of the NO_x and SO_2 caps relative to the timing of the CO_2 cap. On one hand, if NO_x and SO_2 caps were imposed and then followed shortly by a CO_2 cap that was unexpected, substantial investments could be made in control equipment that would later prove uneconomical. On the other hand, if the CO_2 cap preceded the NO_x and SO_2 caps, the potential for uneconomical investments in control equipment would appear to be small.

A rough measure of the maximum potential for savings in a coordinated approach would be to compare the cost increase projected in an integrated case with the sum of the cost increases projected in the cases that impose each emission cap individually. Table 12 shows the calculations for the integrated 1990-7% 2005 case and the standalone NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 cases with and without allowance fees. The values without allowance fees (often referred to as "resource costs") represent just the expected increases in expenditures on fuel and other operating costs and the increased investments in new emission control equipment and new capacity. The projected savings in total resource costs are higher in the early years—as much as $6 billion in 2006—because in the integrated cases the expected investments in control equipment to remove NO_x and SO_2 to meet the respective 2005 caps are less than those expected in the NO_x and SO_2 cap cases. After 2015, the projected savings in total resource costs are small. In the integrated case many of the plants to which controls might have been added are expected to be retired.

As might be expected, the impact of the assumed CO_2 emission caps on electricity prices is projected to be fairly sensitive to the stringency of the caps (Figure 12). For example, in the CO_2 1990-7% 2005 case, the price of electricity in 2010 is projected to be 42 percent above the reference case level. In the less stringent CO_2 sensitivity case, however, the difference is expected to be 29 percent. Similarly, average electricity prices in 2010 in the integrated 1990-7% 2005 case are projected to be 43 percent higher than projected in the reference case level, but in the integrated sensitivity case they are projected to be 30 percent above the reference case projection.

The higher electricity prices projected in the analysis cases, particularly those with CO_2 caps, lead to lower total consumption of electricity. In response to higher projected prices, consumers are expected to make efforts to reduce their electricity use (Figure 13). Efforts may include switching to other fuels, buying more efficient appliances and equipment, and simply reducing the usage of electricity-using devices. The projected small price changes in the NO_x and SO_2 cap cases are expected to lead to little change in consumer electricity consumption. In these cases, total electricity sales in 2010 are projected to be only slightly lower than in the reference case. The impact on consumer electricity use is expected to be much larger in the cases with CO_2 emission caps, where the demand for electricity is expected to be between 5.8 and 7.6 percent (241 to 314 billion kilowatthours) below the reference case in 2010.[15]

In some cases, consumers' efforts to reduce their electricity consumption could partially offset the CO_2 emissions reductions in the electricity sector. For example, if an industrial consumer reduces electricity consumption by using more coal, oil, or gas on site, the CO_2 emissions reductions that occur in the power sector could be partially offset by increases in the industrial sector. "Leakage," as it is commonly called, is always a possibility when emission caps are imposed on one sector of the economy while other sectors are not similarly constrained. The degree to which it occurs will depend on several factors, including the substitutability of other fuels for electricity in the residential, commercial, and industrial sectors and the overall economic impacts of

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[15] The tendency of consumers to switch from electricity to natural gas is expected to be reduced somewhat by the increase in gas prices that would result from increased use of natural gas by eleectricity generators to meet the emission targets.

Table 12. Projected Changes from Reference Case Estimate of Total Costs of Service for U.S. Electricity Generators, 2005-2015

(Billion 1999 Dollars)

Year	NO_x 2005 Case	SO_2 2005 Case	$CO_2$1990-7% 2005 Case	Sum: NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 Cases	Integrated 1990-7% Case Projected Costs	Integrated 1990-7% Case Projected Savings
Including Allowance Costs in Total Costs						
2005	3	3	77	82	77	5
2006	4	3	70	77	68	9
2007	3	4	77	83	74	9
2008	3	3	89	96	87	8
2009	2	4	86	92	88	5
2010	2	4	88	94	86	9
2011	2	4	87	94	84	9
2012	3	5	90	97	87	11
2013	2	3	89	94	89	5
2014	3	3	89	96	87	9
2015	2	3	85	90	86	5
Excluding Allowance Costs from Total Costs						
2005	2	3	21	26	24	2
2006	3	4	20	28	22	6
2007	2	4	22	28	23	5
2008	3	3	27	32	28	4
2009	2	3	26	30	28	2
2010	2	3	28	33	28	5
2011	1	3	28	32	29	3
2012	1	3	29	34	29	5
2013	1	2	30	33	30	3
2014	2	2	31	36	31	4
2015	1	2	29	33	32	1

Note: Totals may not equal sum of components due to independent rounding.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

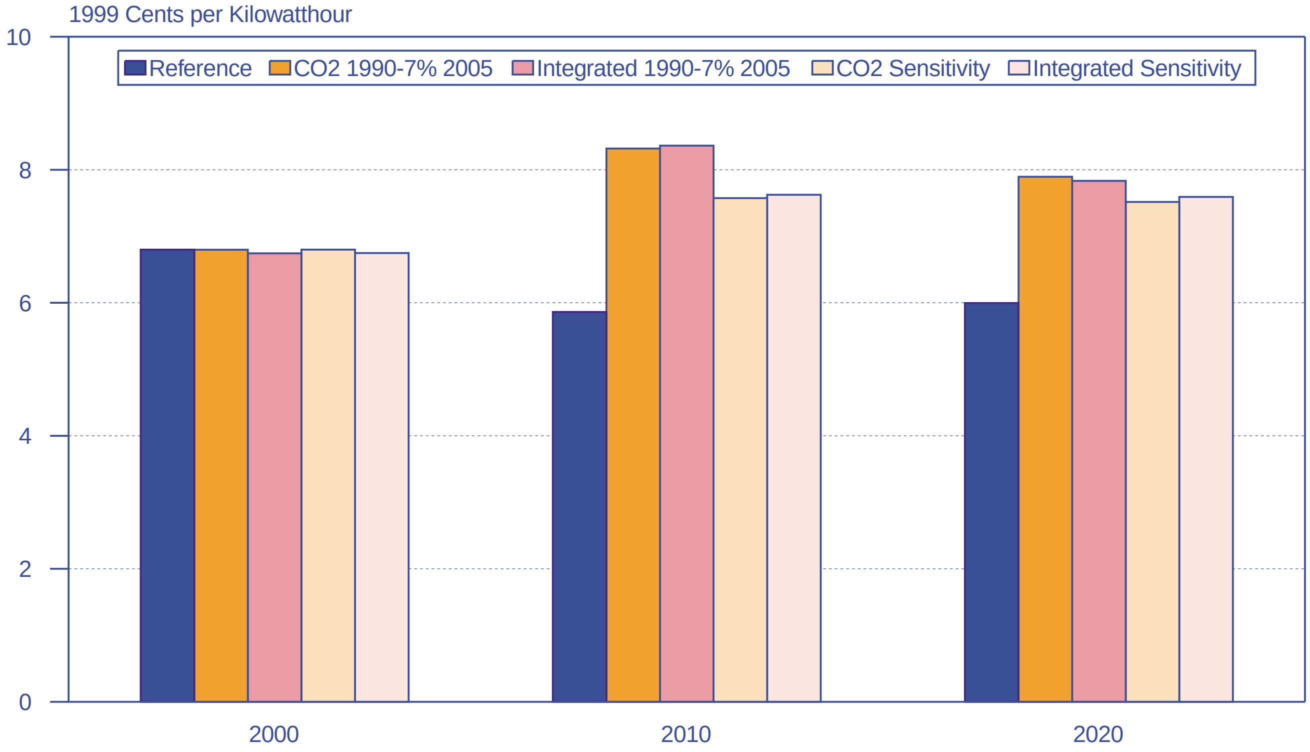
higher electricity and natural gas prices and lower coal prices resulting from the electricity sector emissions caps.

As mentioned above, in this analysis projected higher electricity prices in the cases with CO_2 caps are expected to cause consumers to reduce their electricity consumption. However, end-use consumers are also projected to face higher natural gas prices as electricity producers turn to gas to reduce their CO_2 emissions. The net effect of these price changes is a slight reduction in non-electricity sector CO_2 emissions relative to the reference case. In other words, leakage of CO_2 emissions is negative rather than positive. The decline in coal prices projected in the cases with CO_2 caps is projected to be relatively small and is not expected to increase the use of coal in the non-electricity sectors. Coal use is virtually nonexistent in the residential and commercial sectors, and its use in the industrial sector is limited. In total, U.S. energy-related CO_2 emissions are projected to be 249 million metric tons carbon equivalent below the reference case level in 2010 and 333 million metric tons below the reference case level in 2020 in the 1990-7% 2005 case. Even after those changes, however, total U.S. energy-related CO_2 emissions are projected to remain 317 and 462 million metric tons above the target set in the Kyoto Protocol in 2010 and 2020, respectively.

Overall, the Nation’s total electricity bill is expected to be higher in the cases with CO_2 caps than in the reference case (Figure 14). The change is smaller in percentage terms than the change in electricity prices because of the projected reduction in electricity usage just discussed. In percentage terms, in 2010 the Nation’s annual electricity bill is projected to range between 25 and 32 percent higher in the cases with CO_2 caps than in the reference case. Because of the vast size of the electricity market, these percentage changes translate to between $60 billion and $77 billion per year.

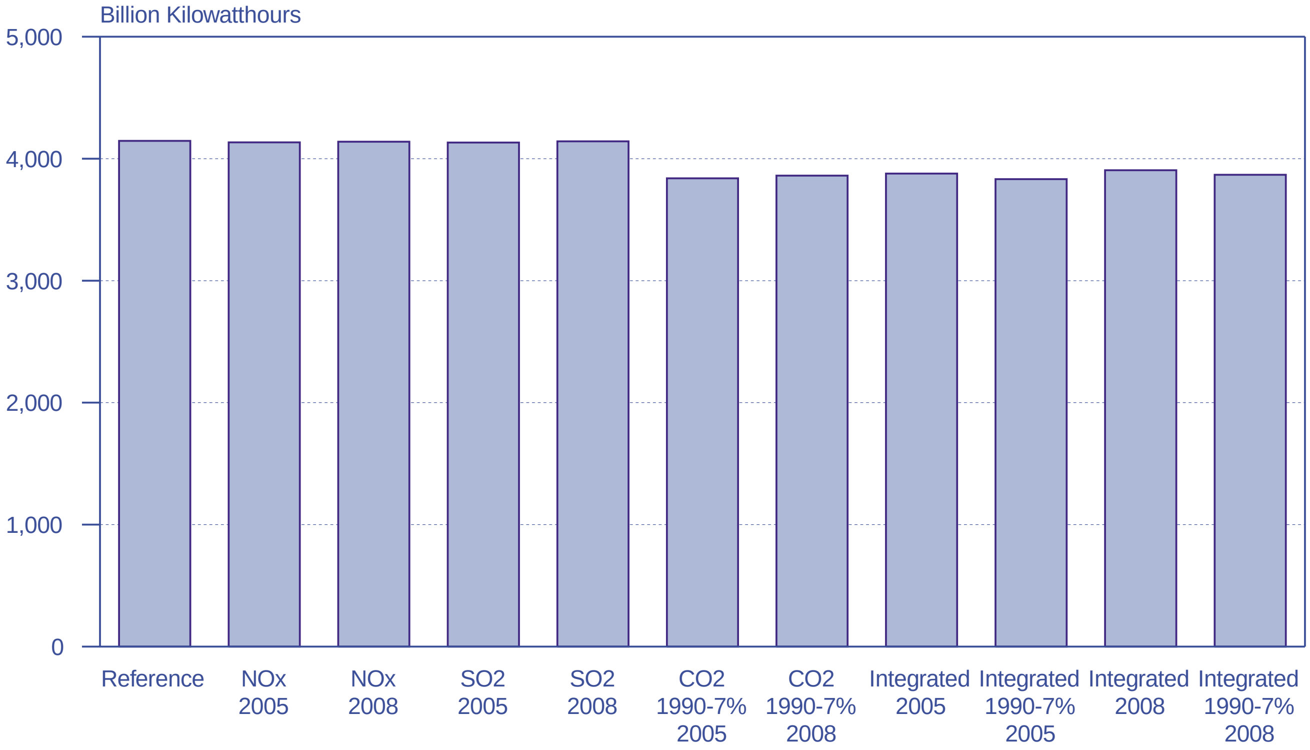
For the average household the projected increases in electricity prices could have a significant impact on annual electricity bills (Figure 15). In the reference case, the annual electricity bill for the average single-family home is estimated to be just over $881 in 1999. It is expected to increase over time, reaching $993 by 2020. In the integrated 1990-7% 2005 case, the annual electricity bill for the average single-family home is estimated to be $1,128 in 2010, or $201 higher than projected in the reference case.

Figure 12. Projected Electricity Prices, 2000, 2010, and 2020



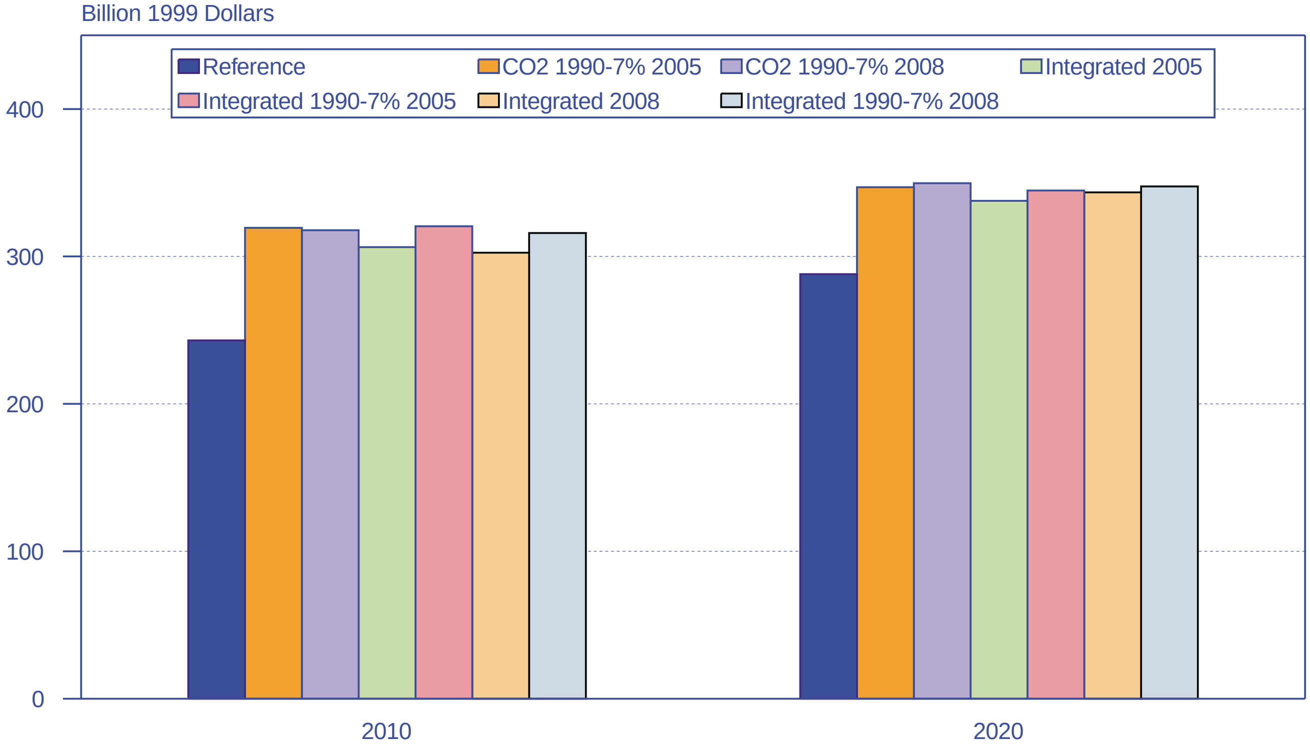
Source: National Energy Modeling System, runs MCBASE.D121300A, FDC7B05.D121300A, FDC7B05H.D121300A, FDP7B05.D121300B, and FDP7B05H.D121300A.

Figure 13. Projected Electricity Sales in 2010



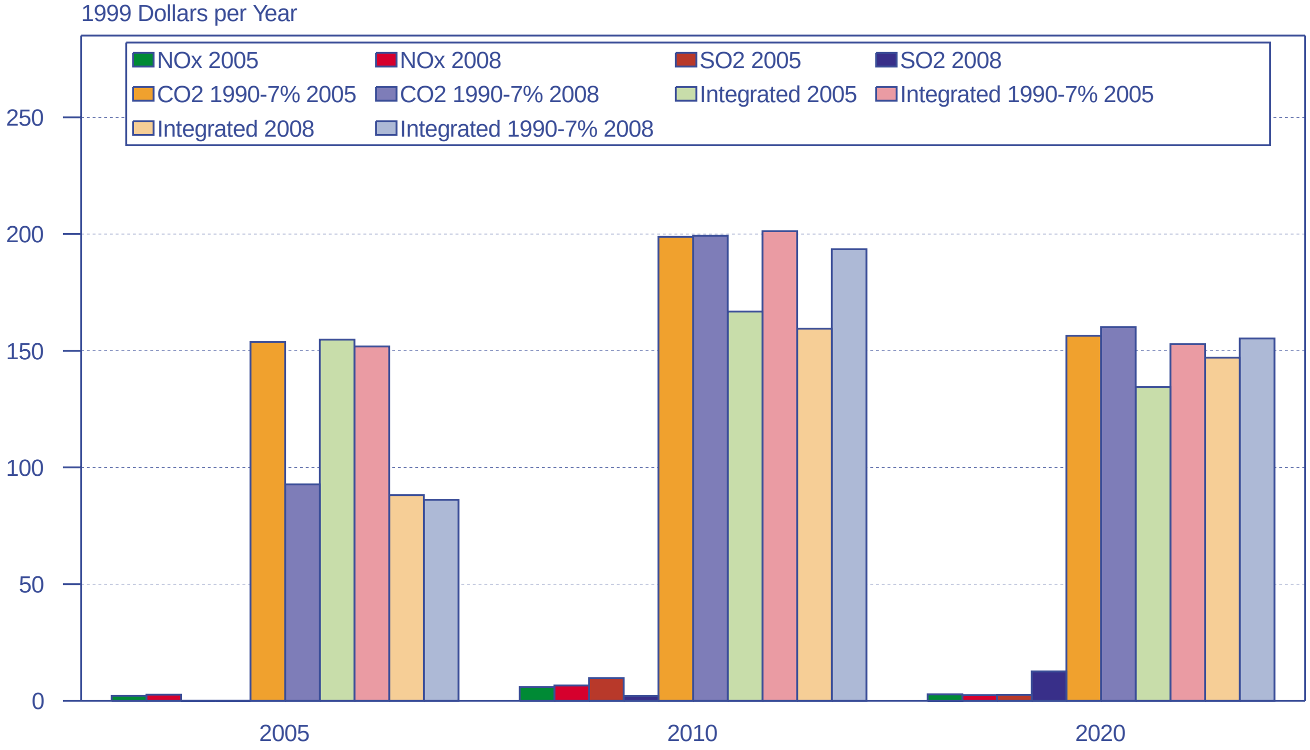
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 14. Total Projected U.S. Annual Electricity Bill, 2010 and 2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.

Figure 15. Average Projected Changes in Annual Household Electricity Bills Relative to Reference Case Projections, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05. D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Summary

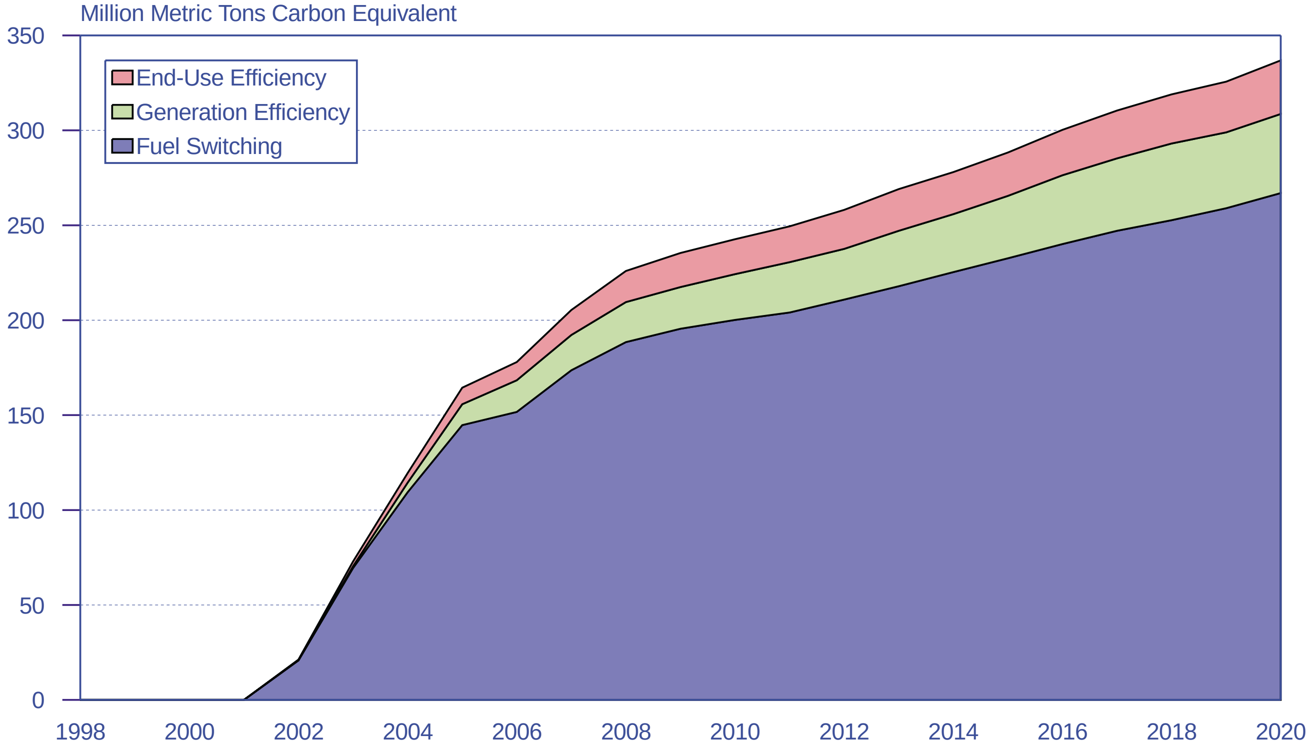
Projected Impacts

Imposing NO_x, SO_2, and CO_2 caps on the power sector is expected to have impacts on all aspects of the electricity generation sector, including capacity expansion and retirement decisions, generation by fuel, and electricity prices. A key result is that the compliance decisions made by power plant operators could be very different if the various emissions caps were imposed together or one at a time on different schedules. Power plant owners would be expected to rely heavily on investments in emission control technologies to comply with the NO_x and SO_2 caps if they were introduced individually or well in advance of a CO_2 cap; but if the NO_x, SO_2, and CO_2 caps were combined, heavy investments in NO_x and SO_2 emission control equipment are not expected to be cost-effective. Rather, many of the coal-fired power plants where such equipment might have been added are projected to be retired if a CO_2 cap is imposed.

When the three emission caps are assumed to be imposed in concert, efforts to comply with the CO_2 cap are projected to have the most significant effect, as can seen by comparing the results for the CO_2 cap and integrated cases. The projected impacts on capacity expansion and retirement, fuel use, and consumer electricity prices are similar in the CO_2 cap and integrated cases. In particular, the most significant increases in consumer electricity prices relative to the reference case projections are seen in the analysis cases that include a CO_2 cap. In the cases without a CO_2 cap, electricity prices are not projected to be more than a few percentage points above the reference case level in 2010 and 2020. In these cases some of the costs associated with adding NO_x and SO_2 control equipment are not expected to be passed on to consumers; rather, they would result in reduced profits for the plant owners who made the investments. In cases with a CO_2 emission cap, electricity prices are expected to be significantly higher. For example, in the integrated 1990-7% 2005 case, the projected electricity prices are 43 percent higher in 2010 and 31 percent higher in 2020 than those projected in the reference case.

Power plant operators and consumers are expected to contribute to the reductions in CO_2 emissions required in the cases with CO_2 caps. Power plant operators are projected to make a dramatic switch from relatively carbon-intensive coal to less carbon-intensive natural gas and carbon-free renewables (Figure 16). The plants built to replace retiring coal plants are also expected to be more efficient, further reducing their CO_2 output per kilowatthour of generation. Consumers are expected to react to higher electricity prices by reducing their consumption of electricity in part through increased investments in more efficient end-use equipment.

Figure 16. Projected Sources of Electricity Sector Reductions in Carbon Dioxide Emissions in the Integrated 1990-7% 2005 Case, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A and FDP7B05.D121300B.

Uncertainty

As with all projections, there is considerable uncertainty in the results of this analysis. Among the key factors that influence the results are the significance of the changes; uncertainty about future fuel prices, particularly for natural gas; changes in policies over the next 10 to 20 years; potential cost and performance improvements in emission control and generating technologies; the ability of the various energy markets to make the adjustments that would be needed over the next 5 to 8 years; the impacts of the ongoing changes in the structure of electricity markets; and the potential impacts of Hg emission regulations. To comply with the emission caps—particularly the CO_2 cap—examined in this report, power suppliers are projected to have to make a rapid shift away from coal-fired plants, which have been the predominant source of electric power in the United States for more than 50 years.

While this analysis suggests that electricity suppliers will be able to move to natural gas and renewable fuels, the potential impacts of a shift of this size, especially over a short time period, are difficult to predict. There is no history to use as a guide for a change of such magnitude. During the transition period there could be significant volatility in the market-based prices of emission allowances and in the wholesale and, potentially, retail prices of electricity. In addition, planning, siting, obtaining environmental permits for, and building the amount of new gas-fired capacity projected to be needed, as well as developing the natural gas resources that would be required to supply them, could be difficult in the time frame assumed here.

Because new natural-gas-fired power plants are expected to be the most important compliance option in the CO_2 cap and integrated cases, natural gas prices are critical in determining the costs of meeting the emission caps. Lower gas prices than those projected in this analysis would reduce the overall compliance costs, and higher prices would increase them.

In the past, when new emissions regulations were imposed, they stimulated research and development that lowered the costs and improved the performance of new emission control equipment and low-emission generating technologies. Because the assumed caps in this analysis would have to be met by 2005 or 2008, however, there would be little time to bring new or improved technologies to the market. Given the normal pace of environmental regulations and compliance dates, the cases with 2005 dates may be unrealistic. With a later compliance date, such improvements could be important. To meet the 2005 caps, however, power plant owners probably would have to rely on currently available technology. There would not be sufficient time to install and test new approaches. In the longer term, NEMS incorporates assumed improvements in cost and performance for new generating and emission control technologies, which reduce the projected costs of complying with the caps. This can be seen by comparing projected compliance costs in 2020 with those in 2010.

The changing structure of U.S. electricity markets—specifically the reliance on competitive markets to set electricity prices—is likely to affect the way in which power suppliers respond to emission caps. It is assumed in this report that independent power producers will dominate new power plant additions, and that wholesale power will be priced competitively.

A key uncertainty with regard to competitive power markets is how consumers and product developers might respond to competitively priced electricity. One feature that has been seen in newly competitive markets is a large amount of price volatility. Because such volatility has not occurred historically, consumers (including homeowners and commercial and industrial establishments) have not invested in equipment that could reduce their exposure to higher prices. It remains to be seen whether the market will become more responsive in the future.

A subsequent EIA service report, to be issued in early 2001, will extend this analysis to examine the impacts of a power sector cap on Hg emissions. It is not possible at this time to predict the impact of the cap in the projections; however, because power sector Hg emissions come almost entirely from coal-fired plants, it is expected that controlling them will lead to higher projected operating costs for those plants. In some cases, coal-fired plants may simply be retired rather than retrofitted with the controls that would be needed.

4. Fuel Market and Macroeconomic Impacts

Coal Markets

Consumption, Production, and Prices

The imposition of new, more stringent emission caps on electricity power plants would affect coal consumption, total and regional production, prices, and industry employment. In general, the revised caps and the consequent need for introducing scrubbers, NO_x reduction equipment, 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. In all the analysis cases, impacts on national coal industry employment levels are projected to be negative relative to the reference case. The overall impacts 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.

In the NO_x cap cases, the additional cost of adding and operating emission control equipment is projected to increase electricity prices slightly and reduce electricity sales by a small amount. The projected coal share of electricity generation by fuel and total projected coal-fired generation in the NO_x cap cases are essentially unchanged from the reference case projections for 2020. Minemouth coal prices in the NO_x 2005 and NO_x 2008 cases track each other closely and range from 5 to 30 cents per ton higher than in the reference case for most of the 2005-2020 period.

In the two primary SO_2 cap cases, slight reductions in coal-fired generation are projected through 2020, as other fuels replace coal. Coal mines that supply medium- or high-sulfur coal are projected to have production declines, leading to lower projected minemouth prices for coal from those sources relative to the prices projected in the reference case (Table 13). To meet the SO_2 emission caps, coal consumption is projected to shift dramatically to favor coal originating from the Powder River Basin (PRB) in Wyoming and Montana, where surface mines working thick coal seams currently achieve levels of labor productivity that are on the order of 6 to 10 times greater than those in many other regions. The resultant low minemouth price of PRB coal and its low sulfur content are projected to lead to additional consumption of PRB coal in the SO_2 cap cases relative to the reference case.

Table 13. Projected Minemouth Coal Prices, 2005-2020
(1999 Dollars per Short Ton)

Analysis Case	2005	2008	2010	2015	2020
Reference	14.76	14.00	13.69	13.37	12.84
NO_x Cap Cases					
NO_x 2005	14.88	14.21	13.99	13.38	12.94
NO_x 2008	14.82	14.11	13.94	13.44	12.95
SO_2 Cap Cases					
SO_2 2005	12.97	12.67	12.41	12.29	11.94
SO_2 2008	13.62	12.52	12.71	12.42	11.87
SO_2 Sensitivity	13.53	12.67	12.59	12.40	12.25
CO_2 Cap Cases					
CO_2 1990-7% 2005	14.78	14.19	13.77	12.94	12.55
CO_2 1990-7% 2008	14.82	14.27	13.72	12.89	12.54
CO_2 Sensitivity	14.88	14.39	13.96	13.03	12.60
Integrated Cases					
Integrated 2005	12.92	12.24	11.93	11.07	10.93
Integrated 1990-7% 2005	13.07	12.53	11.82	11.32	11.18
Integrated 2008	13.70	12.07	11.86	11.25	10.87
Integrated 1990-7% 2008	13.70	12.44	12.03	11.56	11.16
Integrated Sensitivity	14.11	13.50	12.97	12.16	11.99

Source: National Energy Modeling System, runs MCBASE.D121300A (reference), MCNOX05.D121300A (NO_x 2005), MCNOX08.D121300A (NO_x 2008), MCSO205.D121300A (SO_2 2005), MCSO208.D121300A (SO_2 2008), MCSO205H.D121300A (SO_2 sensitivity), FDC7B05.D121300A (CO_2 1990-7% 2005), FDC7B08.D121300A (CO_2 1990-7% 2008), FDC7B05H.D121300A (CO_2 sensitivity), FDPOL05.D121300A (integrated 2005), FDP7B05. D121300B (integrated 1990-7% 2005), FDPOL08.D121500A (integrated 2008), FDP7B08.D121500A (integrated 1990-7% 2008), and FDP7B05H. D121300A (integrated sensitivity).

Because PRB coal has a lower energy content per ton than the average coal now burned, more of it is needed to produce comparable amounts of electricity, and its minemouth price per ton reflects its lower energy value. As a result, the quantity of PRB coal consumed for electricity generation and its minemouth price are projected to increase over time in the SO_2 cap cases, rising above the projected levels in the reference case. The low projected minemouth price for PRB coal and the expected increase in its market share combine to reduce both the projected national average minemouth price and the delivered price of coal to electricity generators relative to the reference case projections.

Sustained growth in electricity demand over the forecast period is projected in the SO_2 cap cases, coupled with projected higher natural gas prices and steady declines in nuclear generation. As a result, continued small annual increases in coal-fired generation are expected in most years through 2020. Although some older coal plants are expected to be retired, plants with scrubbers and highly efficient, low-emitting advanced coal technology units are projected to be placed into service. Following sharp declines in the initial years of the forecast in the SO_2 cap cases, coal production east of the Mississippi River is projected to recover gradually, for consumption in plants that have been retrofitted with scrubbers or in advanced coal plants. Eastern coal has a relatively high energy content, which permits greater generation of electricity per ton of coal burned. In the SO_2 sensitivity case, lower projected allowance prices are expected to lead to approximately 52 gigawatts of scrubber retrofits, as compared with 127 gigawatts projected in the SO_2 2005 case.

In the CO_2 cap cases, substantial reductions in coal consumption are projected, with corresponding drops in the projections for coal production (Table 14). To continue using coal in the CO_2 cap cases, a power plant operator would have to pay for the coal and for the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2005 case, the delivered price of coal in 2010 is projected to average $0.92 per million Btu, and CO_2 allowances are projected to cost $3.65 on a per million Btu basis. Thus, the effective cost of using coal is projected to be $4.57 per million Btu in 2010 and $4.41 per million Btu in 2020 in the CO_2 1990-7% 2005 case. The corresponding costs in the reference case are projected to be $1.05 and $0.98 per million Btu in 2010 and 2020, respectively.

In all the cases with CO_2 caps, continued use of coal is projected to be reduced sharply at many plants. When the allowance price is accounted for, the effective delivered price of coal is quadrupled relative to the reference case (Table 15). Although the average delivered price for coal on a Btu basis still is projected to be below that for natural gas (which has a lower carbon allowance fee), the higher efficiency of natural gas generation is expected to tip the balance away from coal generation in many regional markets.

As existing coal-fired power plants become uneconomical in the CO_2 cap cases, large blocks of capacity are projected to be retired and replaced by natural gas capacity. The combined effects of lower coal capacity and lower utilization of the remaining coal capacity is projected to reduce coal consumption for electricity generation to levels that are approximately one-third of those in the

Table 14. Projected Coal Production, 2005-2020
(Million Short Tons)

Analysis Case	2005	2008	2010	2015	2020
Reference	1,235	1,283	1,297	1,310	1,342
NO_x Cap Cases					
NO_x 2005	1,226	1,263	1,265	1,288	1,324
NO_x 2008	1,224	1,263	1,268	1,283	1,320
SO_2 Cap Cases					
SO_2 2005	1,268	1,296	1,283	1,317	1,346
SO_2 2008	1,262	1,304	1,310	1,324	1,359
SO_2 Sensitivity	1,249	1,286	1,295	1,311	1,336
CO_2 Cap Cases					
CO_2 1990-7% 2005	805	701	681	617	574
CO_2 1990-7% 2008	986	795	651	620	570
CO_2 Sensitivity	932	885	859	793	731
Integrated Cases					
Integrated 2005	821	827	793	725	663
Integrated 1990-7% 2005	816	727	721	655	574
Integrated 2008	988	824	799	720	660
Integrated 1990-7% 2008	998	828	655	635	565
Integrated Sensitivity	940	900	869	797	726

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

Table 15. Projected Delivered Coal Prices to Electricity Generators, 2005-2020
(1999 Dollars per Million Btu)

Analysis Case	2005	2008	2010	2015	2020
Reference	1.13	1.07	1.05	1.01	0.98
NO_x Cap Cases					
NO_x 2005	1.13	1.08	1.06	1.03	0.99
NO_x 2008	1.13	1.08	1.06	1.02	0.99
SO_2 Cap Cases					
SO_2 2005	1.05	1.01	0.99	0.96	0.93
SO_2 2008	1.05	1.01	1.00	0.97	0.93
SO_2 Sensitivity	1.10	1.05	1.02	0.99	0.96
CO_2 Cap Cases					
CO_2 1990-7% 2005	0.99	0.94	0.92	0.86	0.82
CO_2 1990-7% 2008	1.02	0.96	0.91	0.85	0.81
CO_2 Sensitivity	1.04	1.01	0.97	0.91	0.85
Integrated Cases					
Integrated 2005	0.97	0.95	0.92	0.85	0.80
Integrated 1990-7% 2005	0.96	0.92	0.90	0.84	0.78
Integrated 2008	1.00	0.93	0.91	0.84	0.80
Integrated 1990-7% 2008	1.00	0.92	0.87	0.84	0.77
Integrated Sensitivity	1.04	0.99	0.96	0.90	0.85
CO_2 Cap Cases (Adjusted)[a]					
CO_2 1990-7% 2005	4.06	4.73	4.57	4.26	4.41
CO_2 1990-7% 2008	3.04	3.73	4.46	4.31	4.37
CO_2 Sensitivity	3.47	3.44	3.58	3.52	3.71
Integrated Cases (Adjusted)[a]					
Integrated 2005	3.91	3.83	3.85	3.39	3.71
Integrated 1990-7% 2005	3.87	4.45	4.35	4.10	4.13
Integrated 2008	2.83	3.55	3.68	3.48	3.79
Integrated 1990-7% 2008	2.83	3.15	4.11	4.13	4.07
Integrated Sensitivity	3.46	3.48	3.56	3.42	3.80

[a] Adjusted prices reflect the addition of carbon allowance fees to the delivered coal prices shown in the upper section of the table.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

reference case projections. Total coal production is projected to decline at a slower rate than demand from the electricity generation sector, however, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to carbon allowance fees) remains essentially unchanged from reference case values. With large reductions in coal-fired generation projected as a result of the carbon allowance fees, SO_2 emissions are projected to be well below the reference case caps, and no additional scrubber retrofits are expected. In the CO_2 sensitivity case, which assumes less stringent CO_2 emission caps, the lower projected carbon allowance fees are expected to lead to higher coal production than projected in the other carbon cap cases. However, minemouth coal prices are projected to be lower than in the reference case, reflecting overall production declines.

In the integrated cases, coal markets are affected primarily by the CO_2 and SO_2 caps. In these cases, carbon allowance fees are projected to result in greatly reduced demand for coal in the electricity generation sector, reducing the expected coal share of total generation by electricity generators and cogenerators in 2020 from 45 percent in the reference case to between 17 and 20 percent in the integrated cases. Total coal production in 2020 ranges from 42 percent to 49 percent of that projected in the reference case.

Natural Gas Markets

Introduction

Natural gas is an important fuel in all sectors of the U.S. economy other than transportation. In 1999, natural gas accounted for 23.7 percent of U.S. energy consumption, making it second only to petroleum in terms of total consumption. U.S. natural gas consumption totaled 21.4 trillion cubic feet in 1999, 0.1 trillion cubic feet less than the 1998 total. The largest user of natural gas is the industrial sector (including cogenerators), which consumed 44 percent of all gas delivered to consumers in 1999. Electricity generation (excluding cogenerators) accounted

Impacts on the Rail Industry

In addition to the substantial contraction of the U.S. coal industry projected in the CO_2 cases for this analysis, the U.S. rail industry, which has about 200,000 employees and derives considerable revenues from coal shipments, also would be greatly affected. In 1999, 751 million tons of the 1,099 million tons of coal produced in the United States (68 percent) was transported to consumers partly or entirely by rail. Coal freight provided Class I railroads with $7.7 billion in revenues (1999 dollars), or 22 percent of all freight revenue earned. Coal freight car loadings and ton-miles tend to be dominated by a handful of railroads. For the major coal-hauling railroads, coal represented 38 percent of all carloadings during 1999. The average revenue received by Class I railroads for hauling coal was $10.31 per ton (1999 dollars).[a]

The National Energy Modeling System does not project financial data for the rail industry in either the reference or analysis cases. On a qualitative basis, however, certain impacts are likely. Particularly in the cases that incorporate CO_2 caps, railroads and other shipping modes would be required to respond to reduced coal traffic and excess transportation capacity by making major, costly adjustments to routes, schedules, equipment, and employment levels. Decreases in coal traffic and increased competitive pressures would lead to lower freight rates and revenues. At the same time, the inefficiencies associated with the reduced scale of operation would increase unit costs of operation. Lower revenues, special charges, and increased unit costs would sharply reduce rail earnings until new sources of freight revenues were developed.

In this report, coal transportation rates, expressed in 1999 dollars per ton, are assumed to decline over time in response to productivity gains. They are also assumed to vary with fuel prices but otherwise to be invariant across cases despite reductions or increases in traffic along any given route. All modes of coal transportation have achieved significant efficiencies over the past 20 years and have been able to pass along a portion of the savings to shippers in the form of lower rates. New equipment, improved scheduling, maintenance, and operating procedures, and more efficient use of labor have reduced average revenues for coal shipments to 1.72 cents per ton-mile in 1998, nearly a 60-percent decline in real terms from 1981. In contrast, average rail revenues for shipments of transportation equipment and chemicals were 10.55 cents and 3.68 cents per ton-mile, respectively.[b] Already intense interregional competition among coal producers seeking to offer the lowest possible delivered cost is another key factor that has helped to push coal transportation prices to lower levels. As a result, it would appear that reducing coal transportation rates at a faster rate to preserve markets would represent a major challenge to railroad managers.

Data published by the American Association of Railroads indicate that labor costs (wages, plus wage supplements) represent nearly 40 percent of total freight operating expenses plus fixed charges for all Class I railroads. Fuel costs, materials and supplies, and equipment rentals are assigned weights of 7 percent, 5 percent, and 11 percent respectively.[c] Reductions in coal traffic that are not offset by increases in traffic for other commodities would be likely to lead to layoffs, reducing wage costs, and to the adoption of other measures to reduce operating costs. However, fixed charges such as depreciation, interest, and taxes would then be distributed over a smaller traffic base, placing upward pressure on rates. Replacing coal traffic with other commodities would be difficult. For example, in 1998 coal accounted for four times more carloads than either the second-place commodity, transportation equipment, or the third-place commodity, chemicals.[b] Both commodities use shipping routes and equipment that are quite different from those for coal.

Progressively deregulated since the Staggers Rail Act of 1980, railroads have made substantial progress in improving productivity and reducing real costs by investing in new and more powerful locomotives, improved maintenance of main-line rights of way, and more efficient use of labor. A major contribution to achieving the joint goals of lower costs and maintenance of service has been made through a number of mergers over the past decade. Mergers have resulted in the emergence of four major railroad companies—two in the East (CSX and Norfolk-Southern) and two in the West (Burlington Northern-Santa Fe and Union Pacific-Southern Pacific). In 1999, Burlington Northern-Santa Fe received 23.2 percent of all commodity revenues from coal, and Union Pacific-Southern Pacific received 20.7 percent.[a]

The adoption of CO_2 emission restrictions is projected to result in a reduction in domestic coal traffic handled by the railroads. As suggested by the results of the CO_2 cap and integrated cases in this analysis, reductions in coal traffic could range from moderate to severe. In all

(continued on page 39)

[a] Source: Association of American Railroads, Freight Commodity Statistics.
[b] Source: Association of American Railroads, “The Rail Transportation of Coal” (January 2000).
[c] Source: Association of American Railroads, AAR Railroad Coal Indexes (September 2000).

Impacts on the Rail Industry (Continued)

the cases with CO_2 caps assumed, western coal, particularly subbituminous coal from the Powder River Basin, is projected to be most severely restricted, because of its dependence on long-distance rail transportation to reach its markets in locations up to 2,000 miles away.

Because the CO_2 reduction cases analyzed in this study project heavier losses in coal production for western than for eastern coalfields, and because much of the production from western coalfields is shipped over long distances to midwestern and eastern markets to satisfy demand for low-sulfur fuel, it is likely that the burden of reduced coal transportation revenues would fall most heavily on railroads in the West—particularly on the Burlington-Northern and Union Pacific systems, which now include the St. Louis Southwestern, the Chicago & Northwestern, the Denver & Rio Grande Western, the Southern Pacific, and the Atchison, Topeka & Santa Fe railroads.

Lignite production in Texas, Louisiana, and North Dakota is also expected to be severely reduced by CO_2 emission restrictions, but the effect on rail revenues is expected to be minor. Because of its inherently low heat content, lignite is predominantly consumed at or close to the place of mining. Although the projected losses of coal production in the individual CO_2 reduction cases are proportionately and absolutely less for Appalachian coal fields than for the Powder River Basin, the two eastern rail systems (CSX and Norfolk Southern) are also highly dependent on coal revenue. In the more severe CO_2 reduction cases, Appalachian coal production could be reduced by one-third to one-half, with potentially serious financial consequences for the eastern rail carriers.

for 16 percent of total consumption in 1999, and the residential and commercial sectors accounted for 24 percent and 16 percent, respectively.

The vast majority of the natural gas consumed in the United States is produced domestically. In 1999, the U.S. natural gas industry produced 18.7 trillion cubic feet, providing 87 percent of total gas consumption. Relative to other fuels, natural gas is second only to coal in domestic production. In 1999 it accounted for 35 percent of the fossil fuels produced in the United States, as measured by energy content. Production of natural gas is concentrated in the central regions of the country, and an expanding system of pipelines allows gas produced along the Gulf Coast to be consumed in the Midwest and in the Northeast. The other element of gas supply is imports. While the United States exported natural gas to Mexico in 1999, it was a net importer from Canada, importing 3.4 trillion cubic feet in 1999. A small amount of liquefied natural gas (LNG) is also imported from overseas, primarily from Algeria. In 1999, gross imports of LNG accounted for less than 5 percent of all U.S. natural gas imports and less than 1 percent of total consumption. By 2020 LNG imports are expected to reach 0.77 trillion cubic feet, or about 13 percent of total gas imports.

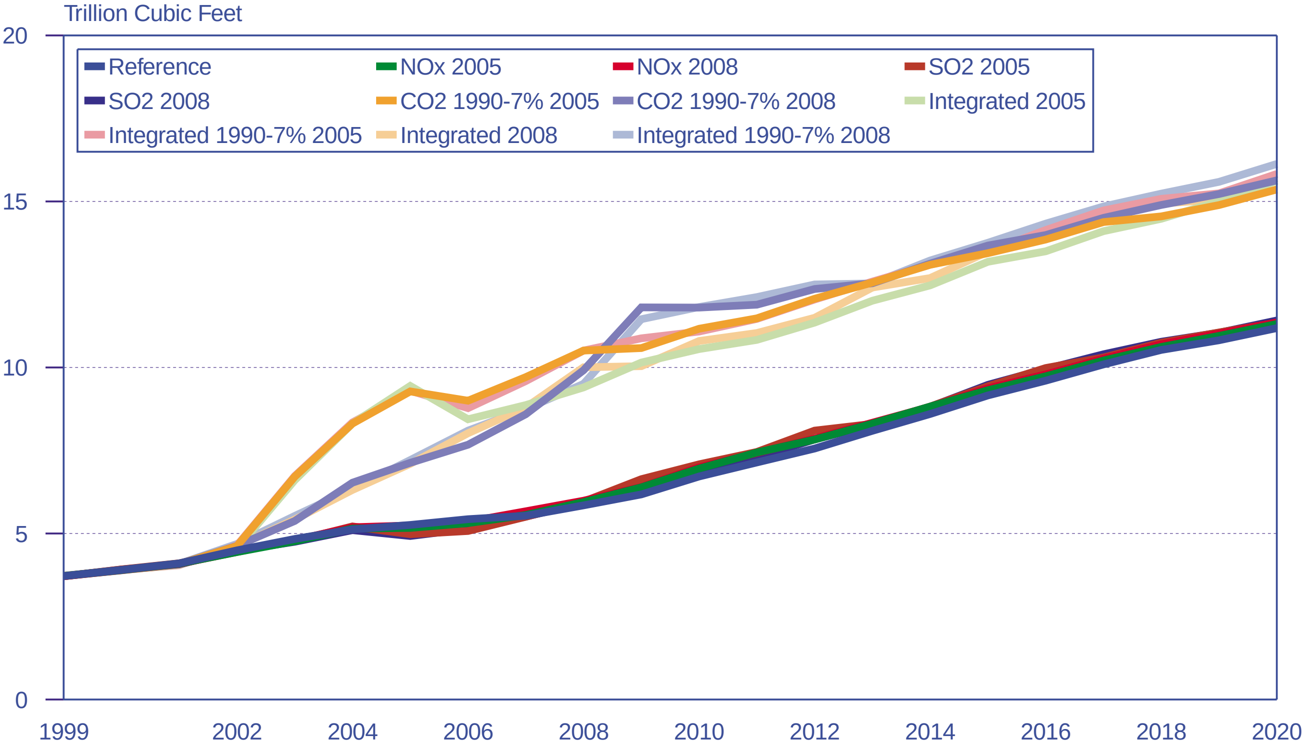
Over the next 20 years, the role of natural gas in U.S. energy markets is expected to increase as its use in the electricity generation sector grows. In the reference case for this analysis, total natural gas consumption is projected to grow to 34.6 trillion cubic feet in 2020, a 57-percent increase over projected consumption in 2000. With total energy use projected to grow by only 30 percent over the same interval, the share provided by natural gas is expected to increase. The largest component of the projected increase in gas consumption in the reference case is the electricity generation sector, which is expected to grow by 5.4 percent per year over the next two decades, as compared with roughly 1-percent annual growth in gas consumption projected for the residential, commercial, and industrial sectors.

The integrated, multi-emission strategies proposed to reduce emissions of NO_x, SO_2, and especially CO_2 are expected to have significant impacts on domestic natural gas consumption, production, and prices. Although the proposed caps are limited to the electricity generation sector, changes in fuel use for power generation would be expected to have significant impacts on the natural gas market as a whole. In the SO_2 and NO_x cap cases, the natural gas market is projected to change only slightly from the reference case, with slightly higher projections for domestic production and consumption in the SO_2 cap cases. Although there are some differences from the reference case projections in these cases, they are minor by comparison with the results of the CO_2 cap cases and the integrated cases, which also include CO_2 caps. Therefore, the discussion that follows concentrates on the CO_2 and integrated cases. The projections for natural gas in the CO_2 cap cases essentially mirror the results of the integrated cases, as the electricity sector switches from coal to natural gas to reduce CO_2 emissions.

Consumption

When CO_2 emission caps are assumed, natural gas consumption is projected to be higher than reference case levels because of higher demand in the electricity generation sector (Figure 17). In the integrated 2005 case, the volume of gas expected to be used for electricity generation increases by more than 5.5 trillion cubic feet (142 percent) from 2000 to 2005, as compared with a corresponding increase of 1.4 trillion cubic feet (35 percent) in the reference case. By 2005, the projection for power

Figure 17. Projected Natural Gas Consumption for Electricity Generation, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

plant use of natural gas in the integrated 2005 case is about 4.2 trillion cubic feet higher than in the reference case. The projected difference between the reference case and the integrated 2005 case narrows to 3.8 trillion cubic feet in 2010, then expands to 4.4 trillion cubic feet in 2020.

The projection for natural gas use by power generators in 2005 in the integrated 2008 case is 2.3 trillion cubic feet (25 percent) lower than in the integrated 2005 case. By 2010, however, the projection is higher in the integrated 2008 case than in the integrated 2005 case, and it continues to be higher for the rest of the forecast period. In the integrated 2008 case, natural gas consumption for electricity generation is projected to grow by only 3.2 trillion cubic feet between 2000 and 2005, but by 2020 the projections for gas use in the power generation sector are nearly the same in these two integrated cases. The projected increases in natural gas consumption in the cases that include CO_2 caps, relative to the reference case, are sensitive to the assumed levels of the emission caps. For example, in the integrated sensitivity case, natural gas consumption for electricity generation is projected to reach 7.8 trillion cubic feet in 2005, 2.6 trillion cubic feet higher than projected in the reference case but 1.5 trillion cubic feet lower than projected in the integrated 1990-7% 2005 case.

Total natural gas consumption is not expected to increase as rapidly as its use for electricity generation in the integrated cases. Because the projected increase in demand for natural gas in the power generation sector is expected to result in higher gas prices, consumption in other sectors of the economy is projected to be lower than projected in the reference case. In general, facing higher prices for natural gas, commercial and industrial users are expected to consume less natural gas than projected in the reference case, either increasing conservation or switching to other fuels. The projected second-order effects of demand from other sectors vary from case to case, based on the level of price increase. In general, however, demand for natural gas in the non-electricity sectors is quite inelastic, and the projected change in natural gas prices between the cases leads to only a limited change in the volumes expected to be used. In the integrated 2005 case, combined commercial, residential, and industrial consumption is projected to be 19.9 trillion cubic feet in 2020, compared with 15.6 trillion cubic feet projected to be consumed for electricity generation. In contrast, commercial, residential, and industrial use in the reference case is estimated to be nearly 0.4 trillion cubic feet higher, at 20.3 trillion cubic feet in 2020. In the integrated cases, higher gas prices and reduced use are projected for the commercial, residential, and industrial sectors, which are not included in the emission caps. The size of the reductions in demand from the non-electricity sectors is dwarfed, however, by the projected increases in gas use for electricity generation, and therefore total natural gas demand is higher when carbon emissions are reduced.

Supply

To meet the expected growth in demand for natural gas, both domestic production and imports are projected to increase above the reference case levels in the integrated cases. In the reference case, both imports and domestic production of natural gas are projected to grow over time, driven by a comparative price advantage for natural gas compared with petroleum and by continued economic growth. By 2020, domestic production is expected to increase by 54 percent, or 10.2 trillion cubic feet, from current levels. Over the same interval, net imports are expected to grow by 66 percent, or 2.3 trillion cubic feet, with most of the growth coming from an increase in imports from Canada. Mexico is expected to remain a net importer of natural gas from the United States in the reference case, and net U.S. LNG imports are projected to increase from 0.1 trillion cubic feet in 2000 to 0.8 trillion cubic feet in 2020.

Figure 18 shows the projected growth in natural gas supply by case between 1999 and 2020. Natural gas supply is projected to increase more rapidly in the integrated cases than in the reference case, as domestic producers are expected to respond to the higher prices associated with increased demand in the power generation sector. The most rapid projected growth in supply is seen in the integrated 2005 cases, but by 2020 natural gas supply is projected to be between 38.5 and 39.0 trillion cubic feet in the cases that include CO_2 emission caps.

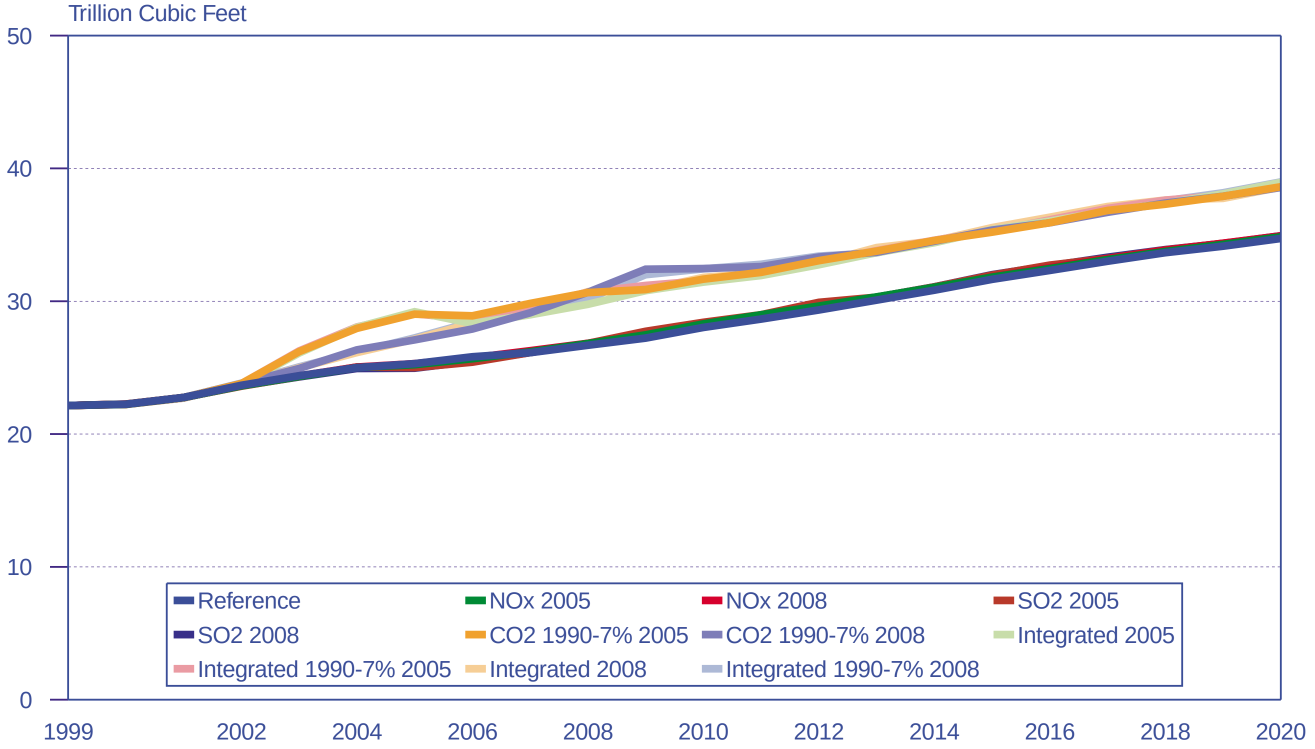
Domestic Production

The projected growth in natural gas production in the reference case is much more rapid than has been seen in recent years. Since 1988, the volume of gas produced domestically has fluctuated between 18 and 20 trillion cubic feet per year. In the reference case, domestic production is expected to expand from 18.6 trillion cubic feet in 2000 to 28.8 trillion cubic feet in 2020. Growth is expected to be fastest in the interval between 2010 and 2015, when annual domestic production is projected to grow by 3.1 trillion cubic feet.

In the cases that include CO_2 emission caps, the projected growth in domestic gas production is even stronger than in the reference case. For example, in the integrated 2005 case, domestic production is projected to grow by 5.1 trillion cubic feet between 2000 and 2005, as compared with 2.1 trillion cubic feet in the reference case. By 2020, however, the projected level of domestic production is only 2.4 trillion cubic feet higher in the integrated 2005 case than in the reference case, because natural gas production after 2005 is projected to increase more rapidly in the reference case than in the integrated 2005 case.

In the integrated 2008 case, gas production is not expected to grow as rapidly as in the integrated 2005 case. Between 2000 and 2005, production in the integrated 2008 case grows by only 3.2 trillion cubic feet, 1.8

Figure 18. Projected Total U.S. Natural Gas Supply, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

trillion cubic feet less than projected in the integrated 2005 case. By 2010, however, annual production in the integrated 2008 case is projected to be 25.5 trillion cubic feet, 0.4 trillion cubic feet higher than projected in the integrated 2005 case. By 2020, projected production in the integrated 2008 case is 0.3 trillion cubic feet higher than in the 2005 case. Earlier, sharper production increases in the 2005 case are expected to lead to a poorer reserve position in the first decade of the projection. Earlier and stronger shifts to renewable technologies in the integrated 2005 case cause projected natural gas consumption, and therefore production, in the later years of the forecast to be higher in the integrated 2008 case than in the integrated 2005 case.

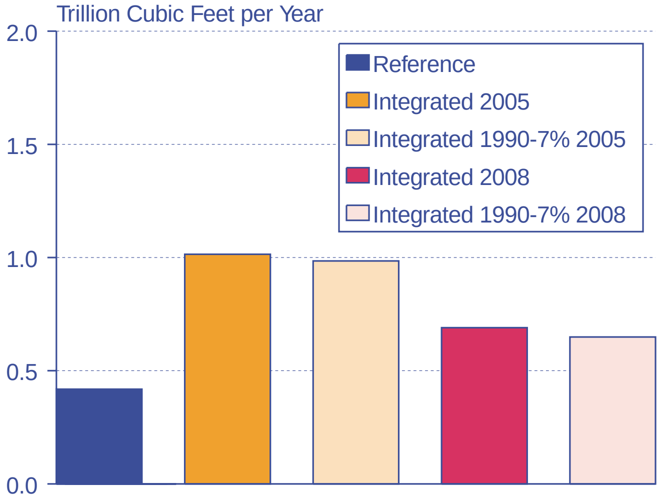
Over time, a much larger volume of gas is expected to be withdrawn from the domestic resource base in the cases with CO_2 emission caps than in the reference case. For example, by 2005, cumulative domestic production (from 2000) in the integrated 2005 case is projected to be 6.4 trillion cubic feet higher than projected in the reference case—an amount equivalent to approximately 4 months of production at current levels. By 2020, the difference in cumulative dry gas production between the integrated 2005 case and the reference case is projected to increase to 36.6 trillion cubic feet, about twice the volume of current production in a typical year. In 2005, cumulative production in the integrated 2005 case is projected to be 4.6 trillion cubic feet higher than in the integrated 2008 case. Although production is generally higher in the integrated 2008 case each year after 2005, cumulative production in 2020 is projected to be lower than in the integrated 2005 case.

Meeting the gas production requirements projected in the cases with stringent CO_2 caps in 2005 would be a challenge for the industry. Production increases of the magnitude projected here have not been seen for many years. The increase in production projected in the integrated 2005 case from 2000 to 2005, at 5.1 trillion cubic feet, is considerably stronger than the recent trend in gas production, which has been essentially flat through most of the 1990s. The most recent period of comparable growth was from 1965 to 1970, when domestic gas production increased by 5.7 trillion cubic feet. Although higher prices would give producers additional revenue, increasing natural gas production by the levels required in the cases with CO_2 emission caps would require considerable investment and effort on the part of the domestic natural gas industry.

On an annual basis, the projected increases in production are far greater than those seen in recent years. Figure 19 shows projected average annual growth in domestic natural gas production between 2000 and 2005 in the reference case and in the integrated cases. The growth rates projected in the two cases with 2005 reduction targets average 1.0 trillion cubic feet per year. The strongest annual growth in natural gas production estimated in the integrated 2005 case is in 2003, when production is projected to grow by 1.9 trillion cubic feet. The projected growth in 2003 is slightly higher in the integrated 1990-7% 2005 case, at 2.0 trillion cubic feet. (Smaller annual increases in production are projected in the integrated cases after 2003, when increases in demand are also expected to slow.) Historically, the largest annual increase in domestic natural gas production was 1.38 trillion cubic feet in 1984, but that increase followed extremely low production in 1983 and therefore can be seen in part as a return to an existing growth trend rather than a shift to a higher production level. During the sustained period of rapid growth between 1965 and 1970, the peak annual increase in natural gas production was 1.34 trillion cubic feet in 1969. The rate of growth projected in the integrated 2005 case during the first 5 years of the projection is unprecedented.

Several issues would need to be addressed for the domestic natural gas industry to meet the high production levels projected in this analysis. One is investment. Lower energy prices in recent years have led to decreases in investment and drilling activity, which have only recently begun to rebound as a result of higher prices for oil and gas. Stimulating additional drilling in the future will require significant additional investment, which is unlikely to be made unless the industry foresees a prolonged period of higher revenues. Given the projections of future domestic production in the integrated cases, however, it is likely that investors would recognize that limits on CO_2 emissions would lead to higher demand for natural gas—and higher prices—for an extended period. In response to those expectations, additional funds are expected to be made available to the industry, providing the necessary capital for

Figure 19. Projected Annual Change in Domestic Natural Gas Production, 2000-2005



Source: National Energy Modeling System, runs MCBASE.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

additional investment in drilling rigs and field development. In contrast, short-term price increases in the early and mid-1990s were not seen as sustainable in the longer term and, therefore, have not led to more drilling.

Under any circumstances, bringing on the number of drilling rigs needed to meet the levels of demand projected in this analysis would be a challenge. Historically, the number of available rigs declined from more than 5,000 in 1982 to fewer than 1,500 in the late 1990s. In the reference case projections, the number of rigs needed is expected to increase by 304 (17 percent) between 2000 and 2005, and in the integrated 2005 case the projected increase is 541 rigs (31 percent) over the same period. However, the industry has shown that it can react quickly to sustained higher prices. Between 1979 and the peak in 1982, the number of oil and gas drilling rigs grew by more than 2,300, an increase of more than 80 percent in a 3-year period.

New oil and gas development technologies are expected to play a role in increasing gas supplies in the reference case. However, because the integrated cases (and especially the integrated 2005 cases) are expected to require rapid production increases in the early years of the projections, they would have to depend more heavily on existing technology and resources, and production costs are projected to be higher in those cases. For example, in the cases that assume CO_2 emission caps in 2005, more natural gas production is expected from offshore fields and unconventional resources than in the reference case. Production from these sources is relatively expensive based on current technology. Thus, the increased production is projected to be more costly than that in the reference case, with corresponding increases in the prices paid by natural gas users. When the CO_2 caps are assumed to go into effect in 2008 rather than 2005, the projected increases in production are delayed accordingly, allowing the time needed for new technologies and resources to come into play and slowing the projected price increases.

Although increasing production capacity is a challenge for the industry, in the long term there are adequate resources to allow production to expand as projected in the most stringent cases in this analysis. The forecasts assume that domestic resources of economically recoverable gas are roughly 1.2 quadrillion cubic feet. In the reference case, cumulative dry gas production from 2000 through 2020 is estimated to be 491 trillion cubic feet, compared with 528 trillion cubic feet in the integrated 2005 case. The additional 37 trillion cubic feet of production over the forecast period represents about 3 percent of the current estimated resource base. Therefore, the difference in the absolute levels of depletion of natural gas resources does not seem to preclude the expansion of gas production projected in the integrated 2005 case.

Imports

Canadian imports make up nearly all the projected increase in imports in the reference case, growing by a projected 2 trillion cubic feet over the next 20 years to a total of 5.5 trillion cubic feet in 2020. (The projections include growth in Canadian imports as a result of increased gas production in Alaska. New Alaskan gas that is not shipped directly to the lower 48 States is used in Canada, freeing up additional Canadian gas for export to the United States.) In the integrated 2005 case, Canadian imports are projected to grow by 2.6 trillion cubic feet—to 6.0 trillion cubic feet in 2020—in response to higher natural gas prices in the United States, and one-half of that increase is expected to occur by 2005.

Higher U.S. gas prices in the integrated 2005 case are also expected to stimulate net LNG imports, which are projected to increase to 1.3 trillion cubic feet by 2020—540 billion cubic feet higher than projected in the reference case. Although projected LNG imports are higher in the integrated cases, LNG remains a relatively small source of gas supply. The projected increase in LNG imports is limited even in the integrated 2005 case, because even with higher prices, additional expansion of LNG capacity is not likely to be economically viable, based on estimates of world supplies and existing technology. Stronger demand in the integrated case also is expected to reverse the flow of gas between the United States and Mexico. In the reference case, 176 billion cubic feet of natural gas is projected to be exported from the United States to Mexico in 2005. In the integrated 2005 case, however, net imports of natural gas from Mexico are expected to total 300 billion cubic feet in 2005, increasing to 360 billion cubic feet in 2020.

In order for imports to the lower 48 States to reach their projected levels in the cases with CO_2 emission caps, the import transportation infrastructure would have to be expanded more rapidly than projected in the reference case. For LNG, the higher import levels projected in the cases with CO_2 emission caps would only require more intensive use of existing regasification plants. In contrast, increasing imports from Canada and Mexico above the levels projected in the reference case would require additional pipeline and other infrastructure development by 2005 and continuing infrastructure development in Canada through 2020. Constructing the infrastructure necessary to meet the demand for natural gas imports projected in the integrated cases would require investment in pipelines and other infrastructure technology. Building the additional pipeline capacity that would be needed to allow an additional 430 billion cubic feet of gas across the Canada-U.S. border (beyond the 730 billion cubic feet of new capacity projected to be needed in the reference case after 1999) to be imported to the lower 48 States by 2005 in the integrated 2005 case would present a challenge to the industry that would require careful planning.

Using the past as a guide, the changes in production and imports that would be needed to meet the projected supply requirements in the CO_2 cap cases are large; however, the required growth is expected to be accompanied by higher projected prices. Thus, although meeting the projected requirements in the analysis cases that include CO_2 emission caps would require significant effort on the part of domestic producers and importers, primarily in the cases with 2005 CO_2 caps, the higher prices projected in those cases are expected to provide the necessary incentives for the industry to add capacity.

Pipeline Capacity

To meet the increased demand projected in the CO_2 cap cases, interstate pipeline capacity is also projected to increase. Additions to existing pipeline capacity are projected in all the cases, but more rapid expansion is expected in the cases with CO_2 emission caps. Between 2000 and 2005, interstate pipeline capacity (defined as the sum of the pipeline volumes crossing State borders) is projected to grow by 4.7 trillion cubic feet (5.1 percent) in the reference case and by 5.4 trillion cubic feet (4.5 percent) in the integrated 2005 case. More rapid growth in pipeline capacity is projected to continue in the integrated case, with the expected addition of 23.3 trillion cubic feet (21 percent) to interstate capacity between 2005 and 2020, as compared with 14.5 trillion cubic feet (13 percent) projected in the reference case over the same interval.

The strongest annual growth in pipeline capacity in the reference case is projected for 2001, at 2.9 trillion cubic feet. The projected increase is based on recently completed projects and the expected completion of projects currently under way, including the Alliance Pipeline running from Canada to the Midwest and the Maritimes / Northeast and Portland Natural Gas Transmission System pipelines running from Canada to the northeastern United States.

Except for the early increase projected for 2001, interstate capacity is projected to grow by 1.84 trillion cubic feet or less each year in the reference case. Greater annual increases are projected in the integrated 2005 case between 2010 and 2020, with the highest annual growth expected in 2014 at 2.1 trillion cubic feet.

The greatest single-year increase in interstate natural gas pipeline capacity in recent years was in 1992, when 1.6 trillion cubic feet of capacity was added. The strong short-term growth in capacity projected in the reference case, including the projected increase of 2.9 trillion cubic feet in 2001, is based on existing projects that are already completed or underway. These projects show how the industry is able to respond to the increased need for pipeline capacity. None of the projected annual increases after 2005 exceed the growth rate resulting from the projects that are currently underway; however, pipeline capacity expansion can require several years of lead time.

Prices

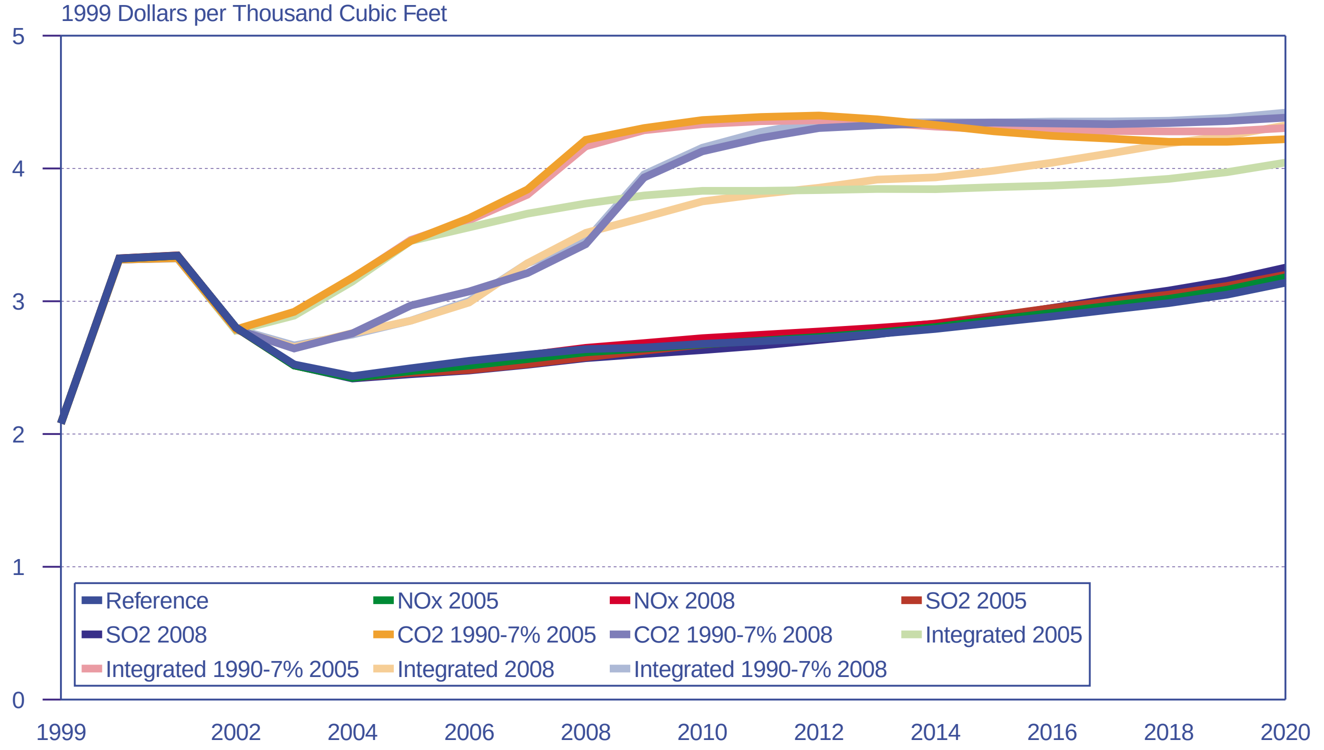
The increased demand for natural gas projected in the cases that include CO_2 emission caps is expected to result in higher prices. In the reference case, the average lower 48 wellhead price of natural gas is projected to be $2.49 per thousand cubic feet in 2005 (1999 dollars), rising to $3.14 per thousand cubic feet in 2020. In the reference case, natural gas wellhead prices of $3.32 and $3.34 per thousand cubic feet are projected for 2000 and 2001, respectively. Although current prices are high, the forecast is based on yearly averages and is designed to capture long-term trends in prices rather than higher prices that might stem from short-term market conditions. However, higher prices in the short term could lead to lower prices in later years of the projections, due to the effects of increased drilling and the resulting higher levels of reserves.

Only minor changes from the gas prices projected in the reference case are expected in the NO_x and SO_2 cap cases. In the CO_2 cap and integrated cases, however, prices are projected to be much higher than in the reference case as a result of the projected rapid increases in natural gas demand. In general, prices are expected to be higher in the 2005 cap cases than in the 2008 cap cases in the years immediately after the caps are assumed to be imposed.

The projected changes in prices from 2000 to 2020 vary by case (Figure 20). Projected wellhead gas prices in the cases with CO_2 caps rise more rapidly than projected in the reference case and end up considerably higher. In the integrated 2005 case, the wellhead price of natural gas in 2005 is projected to be $3.45 per thousand cubic feet, or $0.96 per thousand cubic feet higher than projected in the reference case. The projected prices in the integrated 2005 case are also higher than those in the reference case in 2020, by $0.91 per thousand cubic feet.

By the end of the forecast period, the natural gas prices projected in the integrated 2008 case are higher than those in the integrated 2005 case. In 2010, prices in the integrated 2008 case are expected to average $3.75 per thousand cubic feet (compared with $3.83 in the integrated 2005 case), rising to $4.32 per thousand cubic feet in 2020 (compared with $4.04 in the integrated 2005 case). The differences are due in part to the continued stronger demand from power generators expected in the integrated 2008 case. Higher prices earlier in the integrated 2005 case are also expected to improve the reserve position and reduce the cost of production in the later years of the forecast. The projected prices in the reference case remain within the historical range, but those in the cases that assume CO_2 caps are higher than they have been in the past, exceeding the 1983 average

Figure 20. Projected Domestic Wellhead Natural Gas Prices, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

wellhead price of $3.94 per thousand cubic feet (1999 dollars), as a result of the projected increases in demand for natural gas by electricity generators.

In the short term (through 2003), the projected increases in natural gas prices in the analysis cases that include CO_2 caps (relative to the reference case projections) result from projected rapid increases in demand for gas in the electricity generation sector, as power plant operators are expected to dispatch gas-fired generators in lieu of coal-fired generators. In the long term, the cumulative market effects of the projected annual increases in demand over the forecast period keep projected prices higher in the cases that include CO_2 emission caps. Thus, although the total projected demand for natural gas in 2020 is only 8 percent higher in the integrated 2005 case than in the reference case, the cumulative increase of 37 trillion cubic feet results in a projected wellhead gas price that is $0.91 per thousand cubic feet, or 29 percent, higher than projected in the reference case.

The projected high prices are expected to have three major effects on the market:

- First, higher wellhead prices are expected to be passed along to consumers as higher end-use prices, reducing the demand for natural gas in other sectors and moderating the expected increase in total demand. For example, in 2005, residential consumers are projected to pay as much as 12 percent more for natural gas in the cases with CO_2 caps than in the reference case. In the integrated 2005 case, electricity generators are projected to pay about $3.91 per million Btu for natural gas, compared with $2.89 in the reference case. Stronger demand and higher wellhead prices are projected to account for the price increase. In addition, electricity generators are projected to pay a CO_2 allowance fee of $1.65 per million Btu. In 2020, the projected price of natural gas for electricity generators in the integrated 2005 case is $4.58 per million Btu plus an allowance fee of $1.63, as compared with $3.68 and no allowance fee in the reference case.

- Second, higher price projections also are expected to result in higher projected revenues for the natural gas industry. Total revenues for gas producers can be estimated by multiplying the average projected wellhead price by projected production. By this measure, estimated industry revenues from gas production are expected to be $52 billion in 2005 in the reference case and $82 billion in the integrated 2005 case. While expanding production increases costs, the increase in revenues should also lead to increased profits for the industry.

- Third, the impact of increased natural gas use in the electricity generation sector would also be felt by consumers in other sectors, because gas prices would increase. Homeowners and the owners of commercial buildings and industrial establishments are projected to see increases in their gas bills in the CO_2 cap and integrated cases. For example, in the integrated 1990-7% 2005 case, total expenditures for natural gas in the non-electricity sectors nationwide are projected to be nearly $25 billion higher in 2010 than projected in the reference case (Table 16). By sector, increases in total expenditures for natural gas relative to the reference case are projected to be $6 billion for the residential sector, $4 billion for the commercial sector, and $15 billion for the industrial sector.

Renewable Fuels Markets

Introduction

Renewable energy technologies, which are virtually emission free, can be attractive alternatives to fossil fuels, especially if emissions need to be reduced. This section discusses the projected impacts of the emission cap cases described in Chapter 2 on renewable capacity additions and generation. The central station renewables analyzed here include biomass, conventional hydroelectricity, geothermal, municipal solid waste, solar energy, and wind.

Biomass fuels include agricultural residues, forestry residues, energy crops, and urban wood waste and mill residues. About 8,000 megawatts of dedicated biomass-fired generating capacity is in use today.[16] Of the total, 6,000 megawatts is used by industrial facilities to produce cogenerated electricity and heat for their own use, primarily in the pulp and paper industry. A new advanced technology, integrated gasification combined-cycle technology, is now entering the market and is assumed to be commercially available beginning in 2005. In addition, energy crops grown specifically to serve as energy fuels are now being tested, and they are assumed to become commercially available in 2010. Among renewables, biomass-fired plants are especially attractive because they can be run nearly continuously, unlike wind and solar facilities that are dependent on intermittent fuel sources. In addition, because biomass growth sequesters CO_2, the use of biomass for electricity generation is considered a net zero CO_2-emitting technology.

In addition to its use in dedicated facilities, it is also assumed that biomass can be used in place of or along with coal in coal-fired plants where it is economically attractive. A small number of coal-fired plants are now using some biomass as part of the fuel mix, and studies have suggested that coal plants could burn between 3 and 5 percent biomass fuel without expensive plant changes. As a result, where biomass fuels are available, it is assumed that up to 5 percent of the fuel used in a coal plant can be biomass based. This level of biomass

Table 16. Projected Total Expenditures for Natural Gas in the Residential, Commercial, and Industrial Sectors, 2005-2020
(Billion 1999 Dollars)

Sector	2005	2008	2010	2015	2020
Reference Case					
Residential	36.21	36.94	37.12	38.56	41.36
Commercial	19.72	20.77	21.35	22.29	23.58
Industrial	33.04	35.50	36.66	40.60	46.50
Total	**88.97**	**93.20**	**95.13**	**101.45**	**111.44**
Integrated 1990-7% 2005 Case					
Residential	39.33	42.31	42.96	43.96	46.16
Commercial	21.76	24.08	24.94	25.92	27.10
Industrial	41.91	49.56	51.84	55.46	59.44
Total	103.01	115.95	119.74	125.34	132.71
Difference Between Cases					
Residential	3.12	5.37	5.83	5.41	4.80
Commercial	2.04	3.31	3.60	3.63	3.52
Industrial	8.87	14.06	15.18	14.86	12.94
Total	14.04	22.74	24.61	23.89	21.27
Percentage Difference Between Cases					
Residential	8.6	14.5	15.7	14.0	11.6
Commercial	10.4	15.9	16.9	16.3	14.9
Industrial	26.8	39.6	41.4	36.6	27.8
Total	15.8	24.4	25.9	23.6	19.1

Source: National Energy Modeling System, runs MCBASE.D121300A and FDP7B05.D121300B.

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[16] Dedicated biomass plants are facilities designed specifically to burn biomass as their primary fuel.

co-firing in coal plants is an economically attractive CO_2 emission reduction strategy, because it can be done at relatively low cost and it displaces a high-carbon fuel. However, because CO_2 reduction scenarios typically reduce expected coal use, opportunities for biomass co-firing with coal are projected to be diminished in such cases.

Geothermal power uses heat from the earth for electric power generation. Accessible geothermal resources can be found in the West and Northwest, although some are near National parks and other environmentally sensitive areas. Nearly 3,000 megawatts of geothermal power capacity is in service today. Like biomass facilities, geothermal plants can be run almost continuously, and they are available whenever power is needed. Some geothermal plants emit small amounts of CO_2.

Municipal solid waste (MSW) includes organic and other combustible urban waste. About 3,000 megawatts of MSW capacity is currently in operation in the United States, most for direct electricity generation and some for cogeneration. MSW conversion to electricity can occur through either solid waste combustion or combustion of landfill gas. Although most of the MSW facilities that exist today use solid waste, this analysis projects that all new MSW capacity will use landfill gas.

Solar power includes solar photovoltaic (PV) and solar thermal facilities. PV, which uses solar cells to convert sunlight directly to electricity, provides grid-serving power in central station plants, distributed units, and modules installed on residences and commercial buildings. PV offers zero emissions, can be installed close to customer loads, and is generally available during high demand periods associated with hot, sunny conditions. PV units are relatively expensive, however, and they are unavailable when the sun is down or blocked. PV is most competitive where solar conditions are best or where peak electricity costs are very high.

Solar thermal concentrates sunlight to produce steam for peaking electricity generation. Currently more than 330 megawatts of solar thermal capacity is in operation in Southern California. When combined with energy storage (such as molten salt), solar thermal can provide reliable power when it is needed. Solar thermal offers zero emissions and, like PV, is generally available during high demand periods associated with hot weather. However, the technology is still in the early stages of development, with relatively high costs and uncertain performance, and inadequate solar conditions east of the Mississippi River limit its potential market.

More than 78,000 megawatts of conventional hydroelectric capacity provides more than 75 percent of all U.S. renewable electricity generation today. Hydroelectric power is a proven, reliable technology with low operating costs. Although there are potential opportunities for additional dams and for capacity additions or efficiency improvements at existing facilities, building new hydroelectric is costly, and environmental objections are significant. The reference case for this analysis projects a slight decline in electricity generation from existing hydroelectric capacity through 2020. Public willingness to accept the construction of new hydroelectric dams currently appears to be low in light of environmental tradeoffs.

Among the renewable generation technologies, central station wind power has shown the most significant growth in recent years, and it is expected to continue to grow in the near future. Spurred by declining capital costs, improving performance, and both Federal and State incentives, total U.S. wind generating capacity is estimated to have increased by nearly 70 percent from 1997 through 2000, to more than 2,700 megawatts. Further near-term additions are also projected.

Like other renewables, wind power produces no emissions, but there are factors that may limit its development. For example, wind resources are often far from electricity customers, and if the wind is not blowing the resources may not be available during peak daily or seasonal loads. Wind power also still costs more than fossil-fueled alternatives. The technology is fairly new and untested on a large scale, and it faces environmental objections, primarily for visual intrusion. In addition, unpredictable variations in output from intermittent generators like wind and solar affect other generators and the overall stability of large interconnected electricity networks, leading to higher costs. The point at which such problems might occur is unknown. For this analysis it is assumed that PV and wind power together can provide no more than 12 percent of any region's annual electricity generation.

Despite some uncertainty about State programs, where sufficient information is available, EIA projections include estimates of new generating capacity using renewable energy resources resulting from current State renewable portfolio standards (RPS), other mandates, green power, and other voluntary programs encouraging renewable energy technologies. State RPS and other mandates are projected to add 5,065 megawatts of new renewable energy capacity by 2020, including 4,377 megawatts from RPS alone. Total RPS and mandated additions include 2,900 megawatts of new wind capacity, 1,145 megawatts of new landfill gas capacity, 840 megawatts of biomass, 117 megawatts of geothermal, and 64 megawatts of new solar (photovoltaic and thermal). Voluntary programs contribute an additional 291 megawatts, 230 megawatts of which is from wind plants, 41 megawatts from landfill gas, 16 megawatts from biomass, and 4 megawatts from solar photovoltaics. The estimates are included in projections for all the cases in this analysis.

Projections of large increases in renewable energy use should be viewed with caution. The availability of renewable energy resources to support major growth is often uncertain, particularly in the case of biomass, geothermal, and wind resources, and the costs and performance of new technologies also are uncertain. Consumer tastes, environmental accommodation, and market acceptance may be problematic, and the ability of different suppliers and regions to integrate large proportions of renewables, especially intermittent sources like solar and wind, into overall supply is not known.

Reference Case Projections

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. In 2000, nonhydroelectric renewables, including both direct generation and industrial cogeneration, are estimated to provide 79 billion kilowatthours (2.1 percent) of all U.S. grid-connected electricity generation and 2.4 percent of retail sales.[17] When the 290 billion kilowatthours of expected conventional hydroelectric generation is included, the total renewable share of U.S. electricity supply in 2000 generation is estimated to be 9.8 percent of generation and 11.0 percent of retail sales. In the reference case, generation from nonhydroelectric renewables is projected to increase to 141 billion kilowatthours in 2020, and its share of total U.S. electricity supply is projected to be 2.7 percent of generation (Figure 21) and 2.9 percent of sales. Generation from conventional hydroelectric capacity is expected to remain essentially unchanged.

Emission Reduction Cases

As the cost of generating power from fossil fuels increases in the emission reduction cases, renewable generation technologies are expected to become more attractive. The projected changes are small in the NO_x and SO_2 cap cases, where the costs of complying with the emission caps are expected to fall mainly on existing fossil plants. New fossil plants, against which new renewable plants would compete when capacity is needed, are assumed to be built to meet current emission standards. Because NO_x and SO_2 emissions from new fossil technologies, especially natural gas facilities, are low, the projected costs of NO_x and SO_2 allowances have little impact on their economics. As a result, as in the reference case, fossil generating technologies (particularly natural gas) continue to be more economical than new renewable capacity in the NO_x and SO_2 cap cases.

The relative economics of new fossil versus new renewable generation technologies change in the CO_2 cap and integrated cases. Carbon allowance fees are expected to raise the costs of all fossil technologies, both existing and new. Natural gas generating technologies are expected to play the key role in reducing CO_2 emissions, but new renewable technologies also are projected to contribute.

Renewables are expected to make their most significant contributions in the most stringent cases, which assume reductions in power sector CO_2 emissions to their 1990 level by 2005 and further to 7 percent below the 1990 level on average over the 2008 to 2012 time period. The CO_2 1990-7% 2005 case projects the greatest increase in renewable energy capacity. In this case, the share of total power generation from nonhydroelectric renewables is projected to increase to 8.0 percent of total generation and 9.2 percent of sales in 2020, much higher than projected in the reference case (404 billion kilowatthours in 2020, as compared with 141 billion kilowatthours in the reference case). Conventional hydroelectric generation is also projected to increase slightly, by 6 billion kilowatthours over the reference case projection for 2020. Nonhydroelectric renewable generating capacity is also projected to make up a larger share of total capacity in 2020 in the CO_2 1990-7% 2005 case than in the reference case (6.3 percent and 2.3 percent, respectively).

The largest increases in renewable electricity generation in the CO_2 1990-7% 2005 case relative to the reference case are projected for biomass, geothermal, and wind (Figure 22). Biomass generation (excluding cogeneration) in 2020 is projected to increase from 22 billion kilowatthours in the reference case to 119 billion kilowatthours in the CO_2 1990-7% 2005 case, with 65 percent of the increase coming from biomass use in dedicated plants and the rest from increased biomass co-firing in coal plants. Geothermal generation in 2020 is projected to increase from 25 billion kilowatthours in the reference case to 113 billion kilowatthours in the CO_2 1990-7% 2005 case. Wind generation in 2020 is projected to increase from 13 billion kilowatthours in the reference case to 86 billion kilowatthours in the CO_2 1990-7% 2005 case, reaching the assumed limit of 12 percent (due to system stability requirements) of total generation in two regions by 2020. Smaller relative increases between the reference case and the CO_2 1990-7% 2005 case in 2020 are projected for landfill gas generation (7 billion kilowatthours) and conventional hydropower (6 billion kilowatthours). Because large-scale central station solar generating technologies are expected to remain more costly than other alternatives in all the analysis cases, they are not projected to provide additional generation relative to the reference case levels.

Although biomass, geothermal, and wind all are projected to provide more electricity generation in the cases with CO_2 caps than in the reference case, their contributions are expected to occur during different parts of

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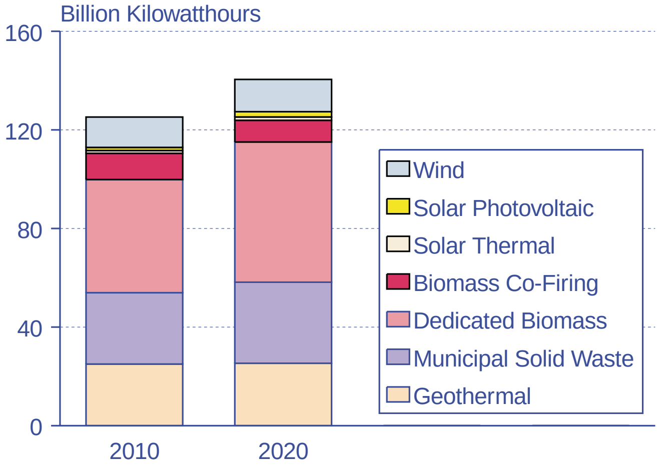
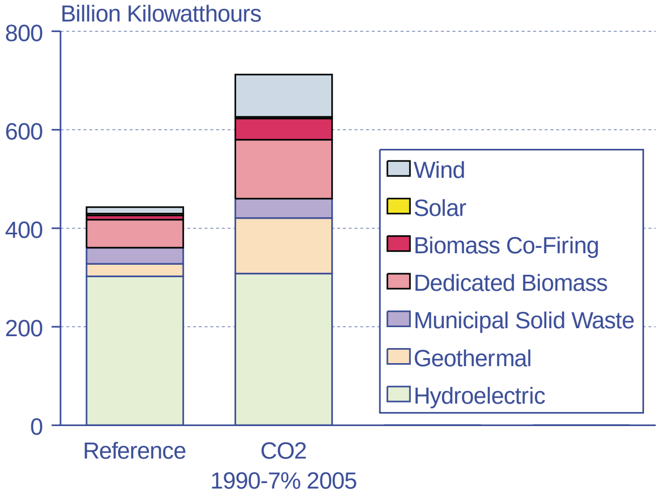
[17] State renewable portfolio standards are variously defined relative to electricity generation or to sales.

Figure 21. Projected Nonhydroelectric Renewable Generation by Fuel in the Reference Case, 2010 and 2020



Source: National Energy Modeling System, run MCBASE. D121300A.

Figure 22. Projected Renewable Electricity Generation by Fuel in the Reference and CO_2 1990-7% 2005 Cases, 2020



Source: National Energy Modeling System, runs MCBASE. D121300A and FDC7B05.D121300A.

the 2000-2020 time period. The vast majority of new dedicated biomass and wind-powered plants are projected to enter service well after 2010, in response to both higher natural gas prices and decreased costs for renewable energy technologies. In contrast, geothermal power and biomass co-firing in coal plants are projected to be economical when the emission caps are first introduced, increasing rapidly in the early years of the forecast. In the later years of the forecast, as less coal-fired capacity remains available, the potential for co-firing declines, and the most cost-effective geothermal opportunities are already taken.

In the CO_2 1990-7% 2005 case, electricity generation from biomass co-firing is projected to increase from 3 billion kilowatthours in 2000 to 38 billion kilowatthours in 2005, peaking at 54 billion kilowatthours in 2010. By comparison biomass co-firing is projected to provide only 11 billion kilowatthours of electricity generation in 2010 in the reference case. After 2010, declining coal-fired capacity is projected to result in reduced biomass co-firing, and its contribution in the CO_2 1990-7% 2005 case slips to 43 billion kilowatthours in 2020. Landfill gas capacity and generation are projected to have accessed almost all available cost-effective sites by 2010, with the result that few additional cost-effective landfill opportunities are expected to be available later in the forecast period.

Most of the increase in renewable fuel use projected in the in the CO_2 1990-7% 2005 case is expected to occur in the western States. The total projected increase in renewable capacity in the CO_2 1990-7% 2005 case relative to the reference case projection for 2020 is 46 gigawatts, of which only 3 gigawatts (6.8 percent) is expected to be located in the five regions along the Atlantic seaboard.

Sensitivity Cases

Because less expensive alternatives can meet most or all of the remaining requirements, reduced mitigation requirements in the sensitivity cases disproportionately reduce—and in one case eliminate altogether—the expansions of renewable energy capacity and generation projected in the integrated cases. In the SO_2 sensitivity case, no additional renewable generating capacity is projected beyond the reference case level. In the integrated sensitivity case, renewable capacity in 2020 is projected to be 16 gigawatts greater than projected in the reference case and 30 gigawatts lower than projected in the CO_2 1990-7% 2005 case.

In the CO_2 1990-7% 2005 case, which assumes the most stringent emission reduction targets in this analysis, renewables enter the projections particularly heavily after 2015, after other less costly alternatives are projected to be exhausted. When less stringent emission caps are assumed, these late-period demands are eliminated, and with them most of the projected additions of new renewable generating capacity in the forecasts. In the electricity generating sector (excluding cogeneration), wind capacity, which is projected to reach 30 gigawatts in the CO_2 1990-7% 2005 case, is projected to reach only 13 gigawatts by 2020 in the integrated sensitivity case—8 gigawatts more than projected in the reference case. Similarly, biomass capacity, which is projected to reach 12 gigawatts by 2020 in the CO_2 1990-7% 2005 case, is projected to reach only 4 gigawatts in the integrated sensitivity case—2 gigawatts more than projected in the reference case.

In contrast to other renewable energy options, biomass co-firing is projected to increase in the integrated sensitivity case compared with the other cases, as most coal-fired capacity is projected to remain in operation through 2020. Whereas in the reference case biomass co-firing with coal produces a maximum of 12 billion kilowatthours of electricity generation in 2011 and provides 9 billion kilowatthours in 2020, in the CO_2 1990-7% 2005 case it is projected to increase to 54 billion kilowatthours in 2010 before declining to 43 billion kilowatthours in 2020. In the integrated sensitivity case, generation from biomass co-fired with coal reaches a projected maximum of 71 billion kilowatthours in 2010 before declining to 56 billion by 2020.

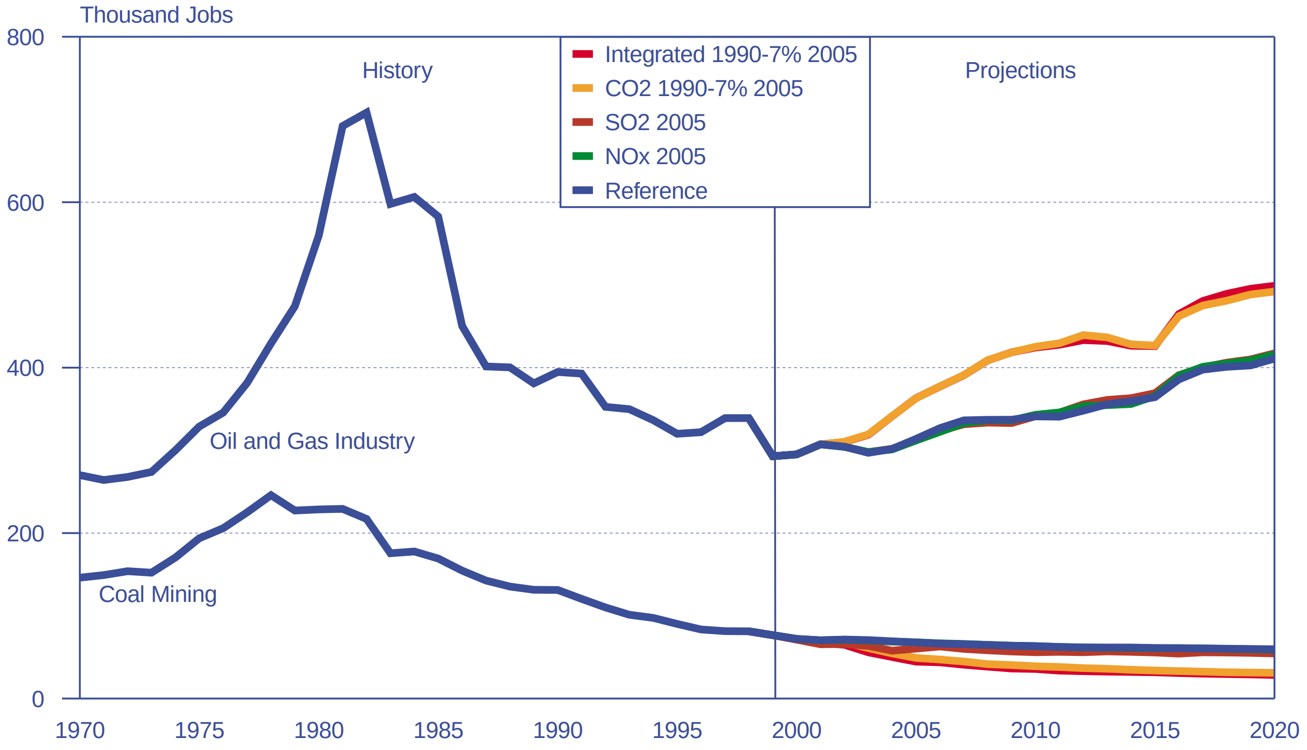
Industry Employment Impacts

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 match projected employment losses in the coal sector in the NO_x and SO_2 cap cases but substantially exceed them in the CO_2 cap cases.

Coal Industry Employment

Between 1978 and 1999, the number of miners employed in the U.S. coal industry fell by 5.4 percent per year, declining from 246,000 to an estimated 77,000. 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 1.8 and 0.5 percent per year are projected from 1999 through 2010 and from 2010 through 2020, respectively (Figure 23). In absolute terms, coal mine employment is projected to decline in the reference case from 77,000 in 1999 to 63,000 in 2010 and 60,000 in 2020.

Figure 23. Coal Mining and Oil and Gas Industry Employment, 1970-2020



Sources: **History:** Coal—Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 1992); and EIA, *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000), and previous issues. Oil and Gas—Bureau of Labor Statistics. **Projections:** National Energy Modeling System, runs MCBASE.D121300A, MCNOX05. D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

In the NO_x and SO_2 cases, overall U.S. coal consumption and production are not significantly different from the reference case. In the NO_x cases the minor changes in coal production, relative to the reference case, lead to only slight changes in coal employment levels, as reductions in NO_x emissions do not significantly affect regional coal production patterns (Table 17). In the SO_2 cases, however, differences in sulfur content by supply region lead to some shifts in the regional distribution of coal production, with output in the relatively high-sulfur, labor-intensive coal fields in the Appalachian and Interior coal supply regions projected to be lower than in the reference case forecast and output from the low-sulfur, less labor-intensive coal mines in the Powder River Basin projected to be higher. In the SO_2 2005 case, U.S. coal mine employment is projected to decline by 1.6 percent per year, from 77,000 miners in 1999 to 55,000 in 2020, compared with a projected decline of 1.2 percent per year in the reference case.

In the CO_2 and 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 1990-7% 2005 case, coal mine employment is projected to decline by 4.7 percent a year, to 28,000 by 2020.

It should also be noted that coal mines typically are located away from cities and are a significant source of income and employment in rural areas. In addition, with substantial contraction of the U.S. coal industry projected in the CO_2 cap cases, employment in the U.S. rail industry, which derives considerable revenues from coal shipments, also would be greatly affected (see box on page 38).

Oil and Gas Employment

Employment in the oil and gas industries is expected to grow in future decades, accompanying the projected increases in drilling and production for natural gas. Employment has fallen since reaching its peak of more than 700,000 employees in 1982. In 1999, average annual employment was 293,000 employees nationally, its lowest level since 1974. In 2000, employment at the end of the third quarter is estimated to have been 20,000 workers higher than it was at the end of the third quarter of 1999, responding to higher prices and increased drilling for oil and natural gas.

In the reference case, total annual average employment in the oil and gas production industry is projected to increase by 1.4 percent and 1.9 percent per year from 1999 to 2010 and from 2010 through 2020, respectively, reaching 411,000 jobs by 2020.[18] The increase is expected to be concentrated in the oil and gas services industry (which includes oil and gas exploration), rather than production. Most of the expected increase is due to the increased level of drilling required to meet the projected strong demand for gas, and to a projected increase in the number of offshore wells.

Projected increases in natural gas use as a result of CO_2 emission caps would require increases in natural gas production, with a significant impact on employment levels in the gas industry. In the integrated 1990-7% 2005 case, average annual employment in 2005 in the oil and gas industry is estimated to be 363,000, roughly 70,000 jobs higher than it was in 1999 and 49,000 higher than projected in the reference case. The difference between the integrated 1990-7% 2005 case and the reference case

Table 17. Projected Impacts on Energy Industry Employment, 2005-2020
(Thousand Jobs)

Industry	Analysis Case	1999[a]	2005	2010	2020	Average Annual Percent Change
Coal	Reference	77	68	63	60	-1.2
	NO_x 2005	77	68	63	59	-1.2
	SO_2 2005	77	60	56	55	-1.6
	CO_2 1990-7% 2005	77	49	39	31	-4.2
	Integrated 1990-7% 2005	77	45	36	28	-4.7
Oil and Gas Extraction . . .	Reference	293	314	341	411	1.6
	NO_x 2005	293	312	343	416	1.7
	SO_2 2005	293	313	341	417	1.7
	CO_2 1990-7% 2005	293	363	425	492	2.5
	Integrated 1990-7% 2005	293	363	424	499	2.6

[a] Preliminary estimates.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

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[18] This analysis uses the econometric forecasting model described in J. Kendell, “Employment Trends in Oil and Gas Extraction,” in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1999*, DOE/EIA-0607(99) (Washington, DC, August 1999).

grows between 2005 and 2010. By 2010, employment in the integrated case is 424,000—more than 83,000 higher than projected in the reference case. Although this projection is more than 130,000 higher than the 1999 employment level, it still is lower than the levels of employment in the oil and gas industry in the late 1970s and early 1980s. By 2020, total employment in the oil and gas industry is projected to reach 499,000 jobs in the integrated 1990-7% 2005 case.

In 2005, projected natural gas production in the integrated 1990-7% 2005 case is roughly 13 percent higher than projected in the reference case, and total employment in the oil and gas industry is nearly 16 percent higher. The difference in employment projections between the scenarios results from an 8-percent increase in the expected number of production workers and a 20-percent increase in the number of service workers relative to the reference case. Thus, the projected increase in employment results primarily from the effort required to bring the new natural gas production on line, including infrastructure development and identification of new resources. Although technology advances tend to reduce the number of workers required to bring new resources into play, the increasing scarcity of new resources makes it harder to bring them on line. Therefore, in the CO_2 cap cases, the increasing difficulty of finding new resources and bringing them to market is expected to cause total oil and gas employment to grow more quickly than total natural gas production.

Renewables Employment

Multi-emission strategies are likely to result in increased U.S. employment in renewable energy industries, in equipment manufacturing, in new facility construction, and in ongoing operation and maintenance of generating facilities using renewable energy. These increases are expected to be small, however, because most renewables—geothermal, solar, and wind, for example—involve little ongoing extraction, preparation, or transportation. Only biomass involves notable labor in energy production, such as for energy crops or for waste preparation. Biomass transportation, while significant, remains local.

Much of the projected new employment in renewable energy industries is expected to be in the manufacturing and construction of new energy generating facilities. To the extent that the United States gains comparative advantage in exporting renewable energy technologies, and to the (relatively small) extent that domestic manufacturing and construction replace imported fuels, U.S. employment is also expected to increase. In addition, some increase in employment is expected for the ongoing operation and maintenance of new renewable energy generating facilities; however, the increase is expected to be small relative to the projected employment increase in the oil and gas industry.

Macroeconomic Impacts

The imposition of new, more stringent emission caps is expected to affect the U.S. economy fundamentally 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 relative prices of capital and labor relative to 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. Table 18 summarizes the projected macroeconomic impacts in the reference and two integrated cases.

In the most stringent case—the integrated 1990-7% 2005 case—inflation in the economy is projected to rise rapidly above the rate 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 be about 1.0 percent above the reference case by 2005 and in 2010 is projected to be 1.2 percent above the reference case projection. After 2010, however, price inflation is projected to abate, and the CPI is expected to begin returning to reference case levels. By 2020, the projected level of the CPI is 0.2 percent above the reference case projection.

How would the projected changes in energy prices affect the general economy? In both of the integrated cases, energy prices are projected to continue increasing relative to the reference case projections through the target year of the emission reduction. The most rapid increases in energy prices are projected during the first 4 years of the forecast period, because the power sector is expected to turn quickly from coal to natural gas to comply with the CO_2 emission caps. Energy prices are projected to continue rising after 2004, but the rate of increase is expected to be more gradual. 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.

Higher energy prices would affect both consumers and businesses. Households would face higher prices for energy and the need to adjust spending patterns. Rising

Table 18. Projected Macroeconomic Impacts in the Reference Case and Two Integrated Emission Reduction Cases, 2005-2020

Projection	2005	2010	2015	2020
Real Gross Domestic Product (Billion 1992 Dollars)				
Reference	9,869	11,461	13,107	14,842
Integrated 1990-7% 2005	9,754	11,401	13,104	14,813
Integrated 1990-7% 2008	9,809	11,377	13,084	14,821
Real Gross Domestic Product (Percent Change from Reference Case)				
Integrated 1990-7% 2005	-1.2	-0.5	0.0	-0.2
Integrated 1990-7% 2008	-0.6	-0.7	-0.2	-0.1
Consumer Price Index (Index, 1982-1984 = 100))				
Reference	193.2	219.7	250.9	295.8
Integrated 1990-7% 2005	195.0	222.3	252.8	296.5
Integrated 1990-7% 2008	194.1	222.0	253.0	297.0
Consumer Price Index (Percent Change from Reference Case)				
Integrated 1990-7% 2005	1.0	1.2	0.8	0.2
Integrated 1990-7% 2008	0.5	1.0	0.8	0.4
Unemployment Rate (Percent)				
Reference	4.2	4.7	4.5	4.1
Integrated 1990-7% 2005	4.8	4.8	4.4	4.1
Integrated 1990-7% 2008	4.5	5.0	4.5	4.1
Unemployment Rate (Change in Rate from Reference Case)				
Integrated 1990-7% 2005	0.6	0.2	-0.1	0.0
Integrated 1990-7% 2008	0.3	0.3	0.0	0.0
Disposable Income (Billion 1992 Dollars)				
Reference	7,053	8,242	9,494	10,858
Integrated 1990-7% 2005	6,956	8,160	9,458	10,808
Integrated 1990-7% 2008	7,000	8,150	9,445	10,813
Disposable Income (Percent Change from Reference Case)				
Integrated 1990-7% 2005	-1.4	-1.0	-0.4	-0.5
Integrated 1990-7% 2008	-0.8	-1.1	-0.5	-0.4
Non-agricultural Employment (Million Employed)				
Reference	140.3	148.6	154.8	161.3
Integrated 1990-7% 2005	138.9	147.9	154.9	161.1
Integrated 1990-7% 2008	139.5	147.6	154.6	161.2
Non-agricultural Employment (Change from Reference Case, Million Employed)				
Integrated 1990-7% 2005	-1.5	-0.7	0.1	-0.2
Integrated 1990-7% 2008	-0.8	-1.0	-0.2	-0.1

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.

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. 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 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

Macroeconomic Effects of Alternative Implementation Instruments

All the cases considered above assume a marketable emission permit system, with a no-cost allocation of the permits based on historical emissions. 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.

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 between 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 1990-7% 2005 case, the magnitude of the transfer would be approximately $30 billion (1992 dollars) in 2010 and almost $40 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, compensating consumers for the higher prices paid for energy and non-energy goods and services.[a]

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 would decline relative to the allocation system. The two effects would tend to counterbalance each other, but not completely. Returning collected auction funds to the consumer would tend to have a slightly more positive effect than the negative effect on investment for the first few years, but after 2005 investment would tend to rebound faster and contribute increasingly to the recovery. As a result, real GDP would be expected to recover to reference case levels faster under the no-cost allocation system. Over the entire period, however, the net impacts on real GDP are expected to be similar in both magnitude and pattern under the two potential allocation schemes.

Another approach is to recycle the auctioned revenues back to either consumers or business through a reduction in marginal tax rates on capital or labor. 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 distortionary taxes on labor and capital toward the taxation of an environmental pollutant. Most often this research 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.[b] Revenue recycling benefits may also apply in a setting where transition effects on the economy, such as considered in the current EIA study, are the focus.[c]

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

[b] 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.

[c] See also 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."

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.[19] Thus, although expectations are important, they are based in general on recent changes, not on forward-looking expectations in the absence of change. A more forward-looking view would suggest that the announcement of a policy would shape expectations and decisions that could lead to reduced impacts on the aggregate economy.

In the integrated 1990-7% 2005 case, the unemployment rate is projected to rise by 0.6 percentage points, reaching 4.8 percent in 2005. 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 fall by 1.2 percent relative to the reference case in 2005, and employment in non-agricultural

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[19] R.E. Brinner and M.J. Lasky, "Model Overview: Theory and Properties of the DRI Model of the U.S. Economy," in *U.S. Quarterly Model Documentation*, Version US97A.

establishments is projected to decline by 1.5 million jobs. Similarly, real disposable income is expected to fall by 1.4 percent. As the economy adjusts to higher energy prices, inflation begins to subside in the forecasts after 2005. At the same time, the economy begins to return to its long-run growth path. By 2010, the projected unemployment rate is only 0.2 percentage points above the reference case, and real GDP is projected to be only 0.5 percent below the reference case projection. The impact on non-agricultural employment is projected to diminish to about 200,000 jobs relative to reference case in 2020. The adjustment process is expected to be nearly complete in 2020, approaching the reference case path, with the unemployment rate at the reference case level and real GDP only 0.2 percent below the reference case level.

In the integrated 1990-7% 2008 case, the energy price impacts are projected to be both smoother and smaller in magnitude. The effect on inflation is projected to be smaller, and the CPI is projected to peak at about 1.0 percent above the reference case level in 2010. As a result the impact on the measures of economic performance is moderated throughout the forecast period relative to that in the integrated 1990-7% 2005 case. The unemployment rate is projected to be 0.3 percentage points above the reference case in the 2005 through 2010 period. The impact on real GDP is projected to reach 0.7 percent below the reference case in 2010, and real disposable income is projected to reach its lowest point at 1.1 percent below the reference case in 2010. As with the integrated 1990-7% 2005 case, the integrated 1990-7% 2008 case projects a strong recovery after 2010, and most of the cyclical impacts are expected to dissipate by 2020, with the unemployment rate returning to the reference case level and real GDP only 0.1 percent below the reference case.

Three key observations follow from these cases:

- The faster the rise in the underlying energy prices, the stronger the cycle introduced in the macroeconomy.
- Given that the emissions caps are assumed to reach a plateau, the economy tends to revert back toward the reference case values in the long run after adjusting to the caps.
- With smaller emission reductions, the projected impacts on the economy are significantly smaller.

5. Potential Impacts of New Source Review Actions

Background

On November 3, 1999, the U.S. Department of Justice, on behalf of the U.S. Environmental Protection Agency (EPA), filed lawsuits against seven electric utility companies in the Midwest and South, charging that 17 of the companies' power plants had illegally released significant amounts of pollutants for two decades.[20] At the same time, the EPA issued an administrative order against the Tennessee Valley Authority (TVA), charging the Federal agency with similar violations at another seven power plants. In addition to the lawsuits and administrative order, the EPA issued notices of violation, naming an additional eight plants owned by other utilities as sites of similar violations of the Clean Air Act (Table 19).

Passed in 1970, the Clean Air Act is the comprehensive Federal law that regulates air emissions from area, mobile, and stationary sources. Among its many provisions is the explicit authorization for the EPA to establish National Ambient Air Quality Standards (NAAQS) in order to protect public health and the environment. The goal of the Act was to achieve the NAAQS by 1975, working in concert with the States through State Implementation Plans (SIPs).

The Clean Air Act was amended in 1977, primarily to set new dates for meeting attainment standards. At the same time, Congress eliminated existing facilities from many of its requirements, exempting them from immediate actions to add pollution control equipment unless they underwent major modifications. "Major modifications" would trigger New Source Review (NSR) standards, and the utilities would, in that event, be required to obtain a permit for Prevention of Significant Deterioration (PSD), which would be granted only if the plants used "best available control technology." Failure to obtain the permit under the conditions specified would leave the utilities liable to legal action and civil penalties.[21]

The dispute in the lawsuits filed for the EPA in November 1999 centers around whether certain modifications or capital improvements performed at the plants named in the action were "major"—specifically, whether the actions were aimed at increasing capacity, regaining lost capacity, or extending the life of the units. Correlatively, the EPA was also concerned with any modifications that would have the effect of increasing emissions.[22] The utilities responded by claiming that the modifications were "routine," undertaken as an integral part of maintaining standard operations at the plants, and thus could not trigger the NSR standards, which contain an explicit exemption for "routine maintenance, repair and replacement."[23] EPA's notice of violations stated that, in some instances, the modifications in question cost tens of millions of dollars and took years to complete. The utilities, however, referenced original plant capitalization costs that in some cases reached $500 million.[24]

Current Status

To date only one of the original cases has been resolved, and settlements have been reached with two other companies accused of similar violations. On February 29, 2000, the U.S. Department of Justice and the EPA jointly announced the settlement of a major Clean Air Act enforcement action against the Tampa Electric Company (TECO). The settlement followed months of negotiations that involved the utility, the two Federal agencies, the Florida Department of Environmental Protection, and the Florida Public Service Commission. The six other utilities and the TVA indicated they would defend themselves against the charges.

[20] Named in the lawsuits were American Electric Power (AEP), Cinergy, FirstEnergy, Illinois Power, Southern Indiana Gas & Electric Company, Southern Company, and Tampa Electric Company. U.S. Department of Justice, "U.S. Sues Electric Utilities in Unprecedented Action To Enforce the Clean Air Act," Press Release No. 524 (November 3, 1999).

[21] For the full text of the Clean Air Act (42 U.S.C. s/s 7401 et seq. (1970)), see U.S. Environmental Protection Agency, web site www.epa.gov/oar/caa/contents.html. Section 109 establishes the NAAQS, Part C sets forth the requirements for the prevention of significant deterioration, Parts C and D define modifications, Section 165 defines major emitting facilities, and Section 113(b)(2) prescribes civil penalties.

[22] Section 111(a) of the Clean Air Act, 42 U.S.C. § 7411(a).

[23] 40 CFR Section 52.21(b) (2) (iii) (a). For an analysis of utility maintenance strategies, see, J.L. Golden, Tennessee Valley Authority, "Routine Maintenance of Electric Generating Stations."

[24] For example, Unit 6 at the Conesville plant, a 444-megawatt unit, was completed in 1978 at an estimated real capital cost of $197 million. See M. McCabe, *An Empirical Analysis of Measurement Errors: Power Plant Construction Costs*. Master's thesis, Massachusetts Institute of Technology (Cambridge, MA, June 1986), Table 1, p. 15.

Table 19. Plants Named in the November 1999 New Source Review Litigation

State and Plant Name	Year of First Commercial Operation	Coal-Fired Capacity (Megawatts)
Alabama		
James H Miller Jr	1978	2,686
EC Gaston	1960	1,884
Barry	1954	1,634
Widows Creek	1952	1,610
Gorgas	1951	1,302
Colbert	1955	1,179
Greene County	1965	255
Florida		
Big Bend	1970	1,683
F J Gannon	1957	1,171
Crist	1959	1,019
Georgia		
Scherer	1982	3,352
Bowen	1971	3,187
Kraft	1958	217
Illinois		
Baldwin	1970	1,751
Indiana		
Cayuga	1970	995
Tanners Creek	1951	980
Wabash River	1953	753
R Gallagher	1958	560
F B Culley	1955	388
Kentucky		
Paradise	1963	2,159
Mississippi		
Jack Watson	1968	774
Ohio		
W H Sammis	1959	2,220
Conesville	1957	1,925
Cardinal	1967	1,800
Muskingum River	1953	1,365
Walter Beckjord	1952	1,118
Tennessee		
Cumberland	1973	2,448
Bull Run	1967	879
Allen	1959	744
John Sevier	1955	704
West Virginia		
Mitchell	1971	1,600
Phil Sporn	1950	1,020

Sources: Energy Information Administration, Form EIA-860A, “Annual Electric Generator Report” (1999); and U.S. Environmental Protection Agency, “A Summary of the Targeted Utilities . . .,” Headquarters Press Release (November 3, 1999).

EPA’s Notice of Violation against TECO stated that modifications undertaken as early as 1979 violated the Clean Air Act. Citing several specific instances at the Gannon plant, EPA said that replacing the furnace floor in 1996, the cyclone burners in 1994, and the second radiant superheater in 1992 constituted major modifications at Gannon. Similarly, the replacement of steam drum internals in both 1991 and 1994 as well as a high-temperature reheater replacement and a waterwall addition in 1994 without simultaneously installing pollution control equipment constituted violations at Big Bend.[25] EPA argued that the law provided for penalties of roughly $9 million per year, per violation, which, for just the violations specifically mentioned, would indicate a civil penalty in excess of $300 million.

Under the terms of a Consent Decree, TECO admitted to no violation of the Clean Air Act but agreed to undertake major efforts to bring its two large coal-fired plants into compliance with the standards promulgated by EPA. The entire Gannon facility, it was agreed, will be repowered to burn natural gas by January 2004. TECO also agreed to improve the use and operation of the scrubbers in use at Big Bend, and to install new combustion controls at Big Bend to reduce NO_x emissions starting in 2002. Major NO_x reductions must be shown at Big Bend by 2007, or TECO may have to repower or retire the units. TECO was forced to surrender its allocation “credits,” which it received under Phase I of the SO_2 reduction program in 1995, and to pay a civil penalty of $3.5 million. TECO also agreed to contribute up to $2 million to study nitrogen deposition in Tampa Bay.[26]

In November 2000, the EPA reached a similar agreement with Dominion Virginia Power regarding three of its coal-fired plants. Although Virginia Power was not named in the November 1999 litigation, the EPA had served a Notice of Violation to the utility in June 2000 for Clean Air Act violations at its Mt. Storm power plant in West Virginia. Under the agreement, Virginia Power agreed to install scrubbers at Mt. Storm units 1 and 2 and to add SCR equipment to all three units at the plant. The utility also agreed to install scrubbers for two units and SCR equipment for three units at its Chesterfield plant and to install SCR equipment on two units at its Chesapeake plant. Virginia Power acceded to a civil penalty of $5.3 million to resolve issues at Mt. Storm and agreed to

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[25] U.S. Environmental Protection Agency, Notice of Violation, EPA-CAA-2000-04-0007.

[26] Consent Decree, Civil Action No. 99-2524 CIV-T-23F.

provide $13.9 million for additional environmental projects, as yet unspecified. Like TECO, Virginia Power agreed to retire a portion of its allowances currently authorized by the Acid Rain program, beginning in 2012.[27]

In December 2000 it was announced that a tentative agreement had also been reached with Cinergy Corporation. Under the terms of the agreement, which must be finalized by the court, Cinergy would shut down or repower with natural gas approximately 600 megawatts of coal-fired generating capacity in Indiana and Ohio between 2004 and 2006; install new scrubbers on four coal-fired units in Indiana between 2008 and 2013; begin operating already-installed SCR units on a year-round basis for two coal-fired plants beginning in 2004; and meet a reduced system-wide NO_x cap by 2008. It was estimated that these actions would cost the company approximately $1.37 billion, making it the largest of the three settlements announced to date. In addition, the company agreed to "retire" 50,000 tons of SO_2 allowances between 2001 and 2005 and reduce its SO_2 cap by 35 percent in 2013. Finally, the company agreed to pay an $8.5 million fine, and to spend $21.5 million on additional environmental cleanup projects over the next 5 years.[28]

The outcome of the other pending lawsuits and regulatory actions is not known at this time. EIA takes no position on how these actions will or should be resolved; however, if the result is that a large number of power plants will be required to add state-of-the-art emissions control equipment in the near future, it could have an impact on the analyses discussed in Chapters 3 and 4 of this report.

Analysis Requested

In light of the developments discussed above, the Subcommittee asked that EIA study the potential impacts of two scenarios with different assumptions about the outcome of the ongoing legal and regulatory actions (see letter of September 25, 2000, in Appendix J). In the first scenario, the Subcommittee asked EIA to assume that the owners of each of the 32 plants named in the NSR litigation must either install best available control technology, convert their coal-fired units to some other fuel source, or retire those units by 2005. SO_2 targets would be reduced by amounts equal to the amount of allowances that would have been earned if the utilities had installed scrubbers at the outset of Phase I of the SO_2 trading program, modeling a "surrender" of allowances as in the TECO settlement. In a second scenario, the Subcommittee asked EIA to assume that all coal-fired plants in the power generation industry would be required to add state-of-the-art emissions control technology, switch to other fuel sources, or retire by 2010.

Four cases were prepared for the analysis described in this chapter:

- Case 1, the *NSR 32 case*, includes all the assumptions of the reference case described in Chapter 2, plus the assumption that each of the 32 coal plants named in the lawsuits by EPA would be required to add FGD equipment to reduce SO_2 and SCR equipment to reduce NO_x by 2005 in order to continue operating. In addition it is assumed that these plants would be required, as was TECO, to give up a portion of the allowances allocated to them in the existing SO_2 program. Although it remains unclear how the cases will be resolved, this analysis case assumes that their basic allowance allocations would be reduced by half, or 600,000 tons.

- Case 2, the *NSR All case*, again includes all the assumptions of the reference case described in Chapter 2, plus the assumption that all coal plants larger than 25 megawatts would be required to add FGD and SCR equipment by 2010 in order to continue operating. As in the NSR 32 case, it is assumed that the owners of the 32 plants named in EPA lawsuits would have to make their decisions by 2005. In addition, it is assumed that when compliance decisions are made in order to meet the summer season NO_x caps in 2004, a decision will also be made about adding NO_x and SO_2 controls, leading to the early addition of control equipment in this case.

- Case 3, the *integrated NSR 32 case*, combines the assumptions of the NSR 32 case with the emission caps assumed in the integrated 1990-7% 2005 case described in Chapter 2. In other words, it is assumed that power sector NO_x and SO_2 emissions would have to be reduced by 75 percent below their 1997 level by 2005, and CO_2 emissions would have to be reduced to their 1990 level by 2005 and further to 7 percent below their 1990 level on average over the 2008 to 2012 period.

- Case 4, the *integrated NSR All case*, combines the assumptions of the NSR All case with the emissions caps assumed in the integrated 1990-7% 2005 case described in Chapter 2.

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[27] "Dominion Virginia Power Reaches Major Agreement with EPA," Electric News Release (November 15, 2000), web site www.dom.com/news/elec2000/pr1115.html.

[28] "Cinergy, EPA, Other Parties Reach Agreement on Power Plant Lawsuit," Cinergy Press Release, web site http://biz.yahoo.com/bw/001221/oh_cinergy_2.html; "Cinergy Agrees to Pay $1.4 Billion to Settle Federal Pollution Lawsuit," Wall Street Journal On-Line, web site http://public.wsj.com/sn/y/SB977502597772054208.html.

In each of the NSR cases the National Energy Modeling System determines the most economical way to comply with the emissions reduction requirements, while at the same time determining whether each of the affected coal plants should be retrofitted with FGD and SCR equipment and continue operating or be retired. The model has the option to add the control equipment to each plant or replace it with one of the 31 new plant types represented. The model chooses the most economical of the 31 options when it decides to replace a plant. It can replace a coal plant with another coal plant, a gas plant, a renewable plant, etc. The option to convert an existing coal plant to burn natural gas is not explicitly represented, because using relatively expensive gas in a plant that is only about 33 percent efficient is generally not economical. The model represents the conversion of a coal plant to natural gas by building a new gas plant and retiring the coal plant.

Results

NSR Base Cases

Table 20 provides summary information comparing the projections in the NSR 32 and NSR All cases with those in the reference case discussed in earlier chapters. In terms of generation by fuel—coal, natural gas, and renewables—the projections in the NSR base cases are similar to those in the reference case, because the requirement to add emission control equipment to some or all existing coal plants does not change the relative economics of operating most of them. In other words, although adding scrubbers and SCR units can be expensive, the operating costs of most of the plants would continue to be competitive after they were retrofitted, and they would continue to be used as they otherwise would have been.

Some coal plants are projected to be retired rather than retrofitted with the required control equipment. For example, in the reference case, 10 gigawatts of coal-fired capacity is expected to be retired between 1999 and 2020. In the NSR 32 case, where retrofit decisions would have to be made for approximately 45 gigawatts of coal-fired capacity, an additional 4 gigawatts of coal-fired capacity is projected to be retired. The vast majority of the plants named in the EPA actions are expected to be retrofitted if it is required. The projections are different in the NSR All case, where retrofit decisions are required for all coal plants. In the NSR All case, 31 gigawatts of coal-fired capacity is projected to be retired by 2020—21 gigawatts more than in the reference case.

An important issue in the NSR All case is the type of capacity that would be built to replace retired coal

Table 20. NSR Reference Case Projections, 2000, 2010, and 2020

Analysis Case	NO_x Emissions (Million Tons)	SO_2 Emissions (Million Tons)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)	Coal-Fired Capacity Retired
2000					
Reference	4.57	11.43	570	6.80	0
2010					
Reference	4.20	9.70	686	5.86	9
NSR 32	3.78	9.10	689	6.01	13
NSR All	1.56	1.94	700	6.11	31
2020					
Reference	4.37	8.95	776	6.00	10
NSR 32	3.90	8.35	777	5.86	14
NSR All	1.62	1.90	784	5.96	31

Analysis Case	SO_2 Scrubbers Added (Gigawatts)	SNCR Added (Gigawatts)	SCR Added (Gigawatts)	SO_2 Allowance Price (1999 Dollars per Ton)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)
2000					
Reference	0	0	0	156	0
2010					
Reference	11	29	86	170	0
NSR 32	40	27	93	137	0
NSR All	195	19	276	0	0
2020					
Reference	15	39	90	246	0
NSR 32	40	32	99	162	0
NSR All	195	19	276	0	0

NA = not applicable. SNCR - selective noncatalytic reduction. SCR - selective catalytic reduction.
Source: National Energy Modeling System, runs MCBASE.D121300A, MC_NSR.D121900A, and NSR_ALL.D121900A.

plants. As discussed in Chapter 3, in the reference case the vast majority of new capacity added—more than 90 percent—is expected to be fueled by natural gas. In that case, however, only a small amount of coal capacity is expected to be retired, and much of the new capacity added is expected to be built to operate in an intermediate load fashion, rather than being built to operate at full load for all hours of the year. New natural gas plants are the most economical option when this intermediate load capacity is needed. In the NSR All case, the retirement of 31 gigawatts of coal capacity is expected to lead to the need for new capacity to operate in a baseload fashion, at full load for most hours of the year. For this type of use, new coal plants—all of which are expected to meet new source emission standards—are projected to be competitive with natural gas plants in many parts of the country. As a result, most of the 31 gigawatts of coal capacity retired in the NSR All case is projected to be replaced with new coal plants. Natural gas plants still are expected to dominate capacity additions—386 gigawatts of 430 gigawatts of capacity added between 1999 and 2020 (90 percent of the total)—but new coal plants are projected to play a bigger role than in the reference case.

Relative to the reference case, the most significant changes in the NSR 32 and NSR All cases are in the projections of power sector NO_x and SO_2 emissions. In both cases, the requirement that coal plants add emissions control equipment to continue operating leads to significant reductions in NO_x and SO_2 emissions relative to the reference case—particularly in the NSR All case. For example, in the NSR All case NO_x emissions are projected to be 1.6 million tons in 2010, just over one-third the level expected in the reference case. The change is even more dramatic for SO_2 emissions, which are projected to be 1.9 million tons in 2010, about 20 percent of the level expected in the reference case. Because the NO_x and SO_2 emission levels in the NSR All case are well below the limits required by the summer season NO_x cap or the SO_2 allowance program established in the Clean Air Act Amendments of 1990, the allowance prices are projected to fall to zero.

The impact on electricity prices is projected to be quite small in the NSR base cases. As noted in the discussion of the NO_x and SO_2 cap cases in Chapter 3, because the costs of adding emissions controls generally do not increase the operating costs of the plants setting the market price for power, the average price of electricity is not expected to increase by much. The price impact is also reduced as a result of the assumption that plants will be forced to add the controls through “command and control” type regulation rather than through a cap and trade program, which would be expected to lead to higher NO_x and SO_2 allowance prices.

Although the price impacts are expected to be small, the power companies required to add control equipment would incur significant costs, particularly in the NSR All case. Between 1999 and 2020, operators of coal-fired power plants are projected to spend \$58 billion to add scrubbers to remove SO_2 and \$15 billion to add SCR NO_x emission control equipment.

Integrated Cases

Table 21 provides summary information comparing the projections in the integrated NSR 32 and integrated NSR All cases with those in the integrated 1990-7% 2005 case discussed in earlier chapters. Again, the projections for generation by fuel—coal, gas, and renewables—are similar among the three cases. The limit on CO_2 emissions in each of these cases is projected to lead to a rapid shift from coal to natural gas and, to a lesser extent, renewable fuels for electricity generation. For example, coal-fired generation in the reference case is projected to be 2,284 billion kilowatthours in 2010, but in these cases it is projected to range between 1,031 and 1,135 billion kilowatthours, roughly 50 percent below the reference case projection. Conversely, natural gas generation in 2010 is projected to be 1,123 billion kilowatthours in the reference case but roughly 69 to 77 percent higher, between 1,839 and 1,988 billion kilowatthours, in the NSR integrated cases.

The major differences among these cases are expected to be in NO_x and SO_2 emissions allowance prices, particularly in the NSR All case. For example, in the integrated 1990-7% 2005 case NO_x emissions in 2010 are projected to be 1.30 million tons, whereas they are projected to be 0.8 million tons in the integrated NSR All case. Similarly, SO_2 emissions are projected to be 3.9 million tons in 2010 in the integrated 1990-7% 2005 case but 1.0 million tons in the integrated NSR All case.

NO_x and SO_2 allowance fees are projected to be lower in the integrated NSR 32 and integrated NSR All cases than they are in the integrated 1990-7% 2005 case, because the requirement for coal plants that continue operating to add emissions control equipment reduces the need for other plant operators to take action to reduce their emissions. In the integrated NSR All case, both the NO_x and SO_2 allowance prices are projected to fall to zero by 2010 and stay there through the rest of the forecast, because the emission targets are assumed to remain at their 2008 levels through 2020.

Electricity prices in the three integrated cases are expected to be similar. The projections for 2010 range between 8.1 cents per kilowatthour and 8.4 cents per kilowatthour, between 37 and 42 percent above the reference case projection. The lower level of coal-fired electricity generation expected in the integrated NSR All case (because more coal plants are projected to be retired) leads to greater dependence on new natural gas plants, which in turn leads to higher projected natural gas prices—\$4.48 in 2020 in the integrated NSR All case versus \$4.30 in the integrated 1990-7% 2005 case.

Table 21. Integrated NSR Case Projections, 2000, 2010, and 2020

Analysis Case	Coal-Fired Generation (Billion Kilowatthours)	Gas-Fired Generation (Billion Kilowatthours)	NO_x Emissions (Million Tons)	SO_2 Emissions (Million Tons)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)
2000						
Integrated 1990-7% 2005 . .	1,943	599	4.6	11.4	570	6.7
2010						
Integrated 1990-7% 2005 . .	1,135	1,839	1.3	3.9	443	8.4
Integrated NSR 32.	1,086	1,903	1.3	3.9	438	8.4
Integrated NSR All.	1,031	1,988	0.8	1.0	442	8.1
2020						
Integrated 1990-7% 2005 . .	852	2,774	1.1	3.3	440	7.8
Integrated NSR 32.	869	2,755	1.1	3.3	439	7.7
Integrated NSR All.	802	2,856	0.8	0.7	442	7.8

Analysis Case	Coal-Fired Capacity Retired	SO_2 Scrubbers Added (Gigawatts)	SNCR Added (Gigawatts)	SCR Added (Gigawatts)	SO_2 Allowance Price (1999 Dollars per Ton)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)
2000						
Integrated 1990-7% 2005 . .	0	0	0	0	150	0
2010						
Integrated 1990-7% 2005 . .	47	10	49	147	226	134
Integrated NSR 32.	74	21	39	134	119	132
Integrated NSR All.	133	103	34	232	0	92
2020						
Integrated 1990-7% 2005 . .	79	17	49	147	99	130
Integrated NSR 32.	94	21	39	134	86	122
Integrated NSR All.	134	103	34	232	0	112

SNCR - selective noncatalytic reduction. SCR - selective catalytic reduction.
Source: National Energy Modeling System, runs FDP7B05.D121300B, FDP_N32.D121900A, and FDP_ALL.D121900A.

Summary

Requiring some or all coal-fired power plants to add equipment to reduce NO_x and SO_2 emissions to continue operating would have a significant impact on NO_x and SO_2 emissions and their respective allowance prices. If the 32 plants currently under suit by the Department of Justice on behalf of the EPA are required to be retrofitted with control equipment to continue operating, as assumed in the NSR 32 case, it is estimated that the SO_2 allowance price in 2010 would be cut by 19 percent relative to the projection in the reference case, from $170 to $137 per ton. Total SO_2 emissions are expected to be 0.6 million tons below the reference case level, because it is assumed that the plants would surrender approximately half their allowances under the terms of an agreement to end the suit.

Similar behavior is expected in the NO_x allowance market. The price impact of requiring the 32 plants to add control equipment is projected to be small. As discussed in Chapter 3, most of the control equipment is expected to be added to plants that do not set the market prices for power, and thus the costs would not be fully passed on to consumers.

The projected impacts on NO_x and SO_2 emissions and allowance prices are even larger in the NSR All case, which assumes that all coal-fired power plants must be retrofitted with control technology if they are to continue operating after 2010. In this case, both NO_x and SO_2 allowance prices are expected to fall to zero, because when new emission control equipment is added to all operating coal plants, NO_x and SO_2 emissions are projected to be well under established emission caps. For example, in the NSR All case, SO_2 emissions in 2010 are projected to be 1.9 million tons, well under the CAAA90 cap of 8.95 million tons.

A large number of coal plants—31 gigawatts (10 percent of existing capacity)—are expected to be retired in the NSR All case, because adding emission control equipment to them would not be economical. When those plants are retired, however, there would be insufficient baseload capacity (plants intended to run almost continuously) if they were not replaced. The vast majority of the plants retired are projected to be replaced by new coal plants that would comply with new source performance standards. As a result, projected CO_2 emissions in the NSR All case are virtually unchanged from those in the reference case. As in the NSR 32 case, electricity prices in the NSR All case are expected to be only slightly above those projected in the reference case. Power plant owners are projected to spend roughly $15 billion on SCR NO_x controls and $58 billion on SO_2 controls, reducing the profitability of the plants but not making them uneconomical.

When the assumptions in the NSR 32 and NSR All cases are combined with those used in the integrated 1990-7% 2005 case described in Chapter 2, the results are similar. Comparing the results in the integrated 1990-7% 2005, integrated NSR 32, and integrated NSR All cases shows that, to meet the emissions targets specified by the Subcommittee, the power sector is projected to reduce its use of coal dramatically and to increase its use of natural gas and, to a lesser extent, renewables.

The requirement that emission control equipment must be added to coal-fired plants if they are to continue operating in the integrated NSR All case is projected to lead to more coal plant retirements than projected in the integrated 1990-7% 2000 or integrated NSR 32 case, leading in turn to a lower CO_2 allowance fee in the integrated NSR All case. It is also projected to lead to even greater dependence on natural gas and, as a result, higher natural gas prices. The projected electricity prices are similar to those in the integrated 1990-7% 2005 case. This analysis suggests that efforts to reduce NO_x and SO_2 emissions at existing coal-fired power plants would make a portion of the plants uneconomical, but the majority would continue operating. Additional effort would be needed to substantially reduce power plant CO_2 emissions.

The analysis in this chapter assumes that affected coal-fired plants would make compliance decisions according to the schedule specified by the Subcommittee. The Subcommittee requested that EIA assume that the 32 plants named in the Justice Department suit would have to be retired or retrofitted with best available control technology by 2005, and that all other coal-fired plants would need to follow suit by 2010. In fact, it is likely that the terms of any settlements with the owners of the affected plants will vary from this strict timetable. The three settlements reached to date allow the companies to take action on a schedule that is somewhat less restrictive than the assumptions made in this analysis. To the extent that the owners of coal-fired plants are required to take the actions assumed in this analysis on a more or less restrictive timetable than EIA has assumed, the cost impacts could also be more or less severe. In addition, if all affected plants were forced to install the required equipment in either 2005 or 2010, it is possible that short-term bottlenecks in acquiring the needed labor and materials could arise, potentially making the cost to the industry higher than indicated by the analysis in this chapter.

6. Comparisons With Other Studies

Introduction

In recent years, significant analysis has been devoted to the problem of reducing individual airborne emissions from electric power plants—either greenhouse gases, of which carbon dioxide (CO_2) is the most pervasive,[29] or any of several criteria pollutants,[30] such as sulfur dioxide (SO_2)[31] and nitrogen oxides (NO_x).[32] Other studies have focused on demand-side innovations, principally in other sectors, that could alleviate power plant emissions.[33] Less attention has been directed to the problem of analyzing multi-emission reduction strategies. This chapter provides a summary of four recent studies addressing the joint reduction of SO_2, NO_x, CO_2, and mercury (Hg) emissions in some combination and compares them, where possible, with the findings of the analysis described in this report.

Over the past several years, the U.S. Environmental Protection Agency (EPA) has used the Integrated Planning Model (IPM) to analyze strategies for reducing emissions of SO_2, NO_x, CO_2, and Hg, first under the Clean Air Power Initiative in 1996 and again in 1999 after soliciting industry reaction and input.[34,35] The Electric Power Research Institute (EPRI) also took up the question of reducing SO_2, NO_x, and CO_2 emissions, examining both cost effects and long-term sustainability.[36] The Environmental Law Institute (ELI) approached the question differently, examining the economic impacts of a 50-percent reduction in coal-fired generation by 2010 using the Resources for the Future (RFF) Haiku electricity market model.[37] Although there are similarities among the studies, they were prepared with different objectives, incorporating different assumptions about emission limits and using different methodologies. As a result, comparisons among them must be made cautiously.

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[29] For example, WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts* (Eddystone, PA, 1998); H.D. Jacoby, R. Eckhaus, A.D. Ellerman, et al., "CO_2 Emission Limits: Economic Adjustments and the Distribution of Burdens," *Energy Journal*, Vol. 18, No. 3 (1997), pp. 31-58; S. Bernow et al., *America's Global Warming Solutions* (Washington, DC: World Wildlife Fund and Energy Foundation, August 1999); H. Geller, S. Bernow, and W. Dougherty, *Meeting America's Kyoto Protocol Target: Policies and Impacts* (Washington, DC: American Council for an Energy-Efficient Economy, December 1999); Congressional Budget Office, *Who Gains and Who Pays Under Carbon-Allowance Trading? The Distributional Effects of Alternative Policy Designs* (Washington, DC, June 2000).

[30] Other criteria pollutants include carbon monoxide, lead, particulate matter (PM_{10}), and volatile organic compounds.

[31] D. Burtraw and E. Mansur, "Environmental Effects of SO_2 Trading and Banking," *Environmental Science & Technology*, Vol. 33, No. 20 (October 15, 1999), p. 3489; K.K. Dhana, "A Market-Based Solution to Acid Rain: The Case of the Sulfur Dioxide (SO_2) Trading Program," *Journal of Public Policy & Marketing*, Vol. 18, No. 2 (Fall 1999), pp. 258-265; R.D. Lile, D. Bohi, and D. Burtraw, *An Assessment of the EPA's SO_2 Emission Allowance Tracking System* (Washington, DC: Resources for the Future, February 1997).

[32] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Final Section 126 Petition Rule* (Washington, DC, December 1999); D. Burtraw, K. Palmer, and A. Paul, *The Welfare Impacts of Restructuring and Environmental Regulatory Reform in the Electric Power Sector* (Washington, DC: Resources for the Future, October 1998), preliminary version; A. Krupnick, V. McConnell, M. Cannon, T. Stoessell, and M. Batz, *Cost-Effective NO_x Control in the Eastern United States* (Washington, DC: Resources for the Future, April 2000).

[33] Interlaboratory Working Group, *Scenarios for a Clean Energy Future*, ORNL / CON-476 and LBNL-44029 (Oak Ridge, TN: Oak Ridge National Laboratory; Berkeley, CA: Lawrence Berkeley National Laboratory, November 2000); J. Koomey, R. Richey, S. Laitner, R. Markel, and C. Marnay, *Technology and Greenhouse Gas Emissions: An Integrated Scenario Analysis Using the LBNL-NEMS Model*, LBNL-42054 (Berkeley, CA: Lawrence Berkeley National Laboratory September 1998); 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). Modeling demand-side reductions in the end-use sectors can produce dramatic results. The *Clean Energy Future* report projects carbon reductions similar to those identified here, with a carbon allowance fee of $50 per ton and limited costs to consumers. Among the assumptions for the power sector necessary to achieve this result, however, are extension of the 1.5 cents per kilowatthour production tax credit through 2004 and capital costs for wind technology of $611 per kilowatt (as compared with $993 per kilowatt in EIA's analysis). Further, other policies in the study serve to reduce projected energy demand, so that energy consumption in 2020 is projected to be about 95 quadrillion Btu, roughly equivalent to maintaining 1998 levels of consumption for the next 20 years.

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

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

[36] Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study*, TR-1000097 (Palo Alto, CA, 2000).

[37] Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000).

The studies discussed here all contain extensive analysis of impacts on the electricity generation sector.[38] Among the key variables examined are changes in capacity type, changes in fuel use and the consequent fuel price responses, changes in the overall generation mix, responses of renewable technologies, and SO_2 allowance prices and carbon allowance fees. However, because the studies assume caps of different levels, on different emissions, over different time periods, and starting from different baselines, straightforward comparisons among the studies are difficult.

In this chapter, the reference cases from the studies are compared, and two of the integrated cases from the EIA analysis are compared with integrated cases from the EPA, EPRI, and ELI studies. Generally speaking, all the studies introduce various emission caps. Beyond that immediate similarity, there are differences in the assumptions made and in the methodologies and, to a lesser extent, the initial baselines used that render highly detailed comparisons difficult. These include:

- **Integrated versus nonintegrated models.** The models used in the studies by EIA, EPRI, EPA, and ELI all have detailed representations of the electricity sector, but details in the representation of other sectors of the energy economy and their interaction with the electricity sector differ. For example, the EIA's National Energy Modeling System (NEMS) endogenously calculates consumer demand for each fuel and the prices at which the fuels are expected to be supplied in order to meet demand. When changes in assumptions (such as adding pollution control equipment or switching fuels to reduce emissions) alter fuel production costs, the projections of fuel prices and consumers' responses to them are recalculated by the model. Because the EPRI analysis used NEMS through 2020 it shares this behavior. In the EPA analysis, electricity demand and a battery of fuel supply curves are determined exogenously. When emission caps are imposed on the electricity generation sector, there are shifts in the demand for different fuels, resulting in different fuel prices (e.g., the wellhead price for natural gas) in the reference and integrated cases. Unlike in the NEMS model, however, fuel supply and demand for the electricity generation sector are not endogenously linked in an integrated system in the EPA model. Thus, the EPA analysis does not include a fuel price response to higher demand or a decline in electricity demand in response to higher prices. The Haiku model contains endogenous electricity demand that responds to changes in prices and upward-sloping fuel supply curves for natural gas and coal.
- **Treatment of nuclear power.** Because nuclear generating units produce no emissions, assumptions about their ability to remain in the generation mix through 2020 can play a key role. In NEMS, maintenance versus retirement decisions for nuclear plants are evaluated endogenously. NEMS weighs the costs of maintaining each nuclear plant against the costs of building a new plant to replace it. When the costs of new fossil plants increase (as in the cases with CO_2 caps in this analysis), the economics of maintaining existing nuclear plants improves, and fewer are retired. In the EPA analysis, nuclear capacity is assumed to decrease from 87 gigawatts in 2005 to 50 gigawatts in 2020. Like NEMS, Haiku has an endogenous nuclear retirement algorithm.
- **Knowledge and ability to react to changing market conditions, including lead time.** Decisionmakers, as represented in models, may have perfect knowledge or very little foresight. As an integrated model, NEMS incorporates macroeconomic feedback in response to the electric power industry's response to emission caps. The model used by EPA does not incorporate this type of response mechanism.
- **Treatment of Emission Caps:** Both the IPM and NEMS are able to model emission caps directly, allowing investments in controls to be made ahead of the control date. The explicit representation also enables the projected allowance prices for each controlled pollutant to be obtained as direct model outputs. Haiku has the ability to model such caps, but the ELI study employs a cap on total coal-fired generation.
- **Representation of Emission Control Technologies:** The IPM, NEMS, and Haiku models allow power plants to choose from an array of control technologies for reducing SO_2 and NO_x; however, the IPM includes a broader array of control technologies than represented in either NEMS or Haiku.

The analyses reviewed here also have some important similarities, the most important being a similar representation of available generating technologies and emission control technologies. All the models can choose to introduce new technologies such as integrated coal gasification units, gas turbines, advanced combined-cycle units, and renewable technologies. The models respond to SO_2 constraints in similar ways, either by means of adding a scrubber retrofit, switching fuels, or economic

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[38] The NEMS model does not analyze or forecast health benefits. One recent estimate projected direct health benefits stemming from the Clean Air Act Amendments of $110 billion in 2010 (1999 dollars). See U.S. Environmental Protection Agency, *The Benefits and Costs of the Clean Air Act 1990 to 2010*, EPA-410-R-99-001 (Washington, DC, November 1999).

retirement. NO_x controls may be introduced during the combustion phase or through post-combustion technologies.[39] CO_2 emissions are constrained through a carbon cap.[40] Finally, all the models show similar starting points for key electric power industry statistics, including total generating capacity, coal-fired capacity, electricity demand, and baseline projections for CO_2 emissions from the electric power industry.

Summary of Studies

EPA's 1999 Emission Reduction Analysis

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 developing and analyzing alternative approaches to reducing three major emissions: SO_2, NO_x, and, potentially, Hg. The analysis used the IPM, a detailed model of the electric power industry in which plant operators react to alternative levels of pollution controls. 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 the most stringent levels modeled, 0.15 pounds per million Btu in 2005. At the same time, SO_2 was reduced in 2010 by lowering the current Clean Air Act Amendments of 1990 (CAAA90) 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, and 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 effort were published in 1996, and the EPA invited interested parties to comment.

EPA's Office of Air and Radiation responded to comments received and modified CAPI in a new series of modeling efforts in 1999. The emissions analyzed were SO_2, NO_x, CO_2, and Hg. Unlike the 1996 study, NO_x emissions were not reduced beyond then-current statutory requirements, such as Phases I and II of the Title IV Acid Rain program or the NO_x SIP (State Implementation Plan) Call, under which 22 States[41] and the District of Columbia must reduce NO_x emissions by 2004. Hypothetical emission caps were developed for each of the remaining emissions. This study allowed a variety of compliance options to meet the emission caps, including fuel switching, repowering, retrofitting or retiring units, and adjusting dispatch.

EPA's 1999 analysis modeled reductions of the emissions singly and, in certain combinations, jointly. SO_2 emissions were reduced from current levels to four alternative levels (by 40 percent, 45 percent, 50 percent, and 55 percent) beginning in 2007, and the targets were assumed to be met in 2010. The analysis cases used the cap and trade approach, with banking of allowances permitted from 2005 to 2007.

Two alternative cases in the EPA analysis examined CO_2 reduction options. The first provided the power industry with 463 million metric tons carbon equivalent per year in allowances and assumed that the industry would find it most economical to purchase an additional 104 million metric tons carbon equivalent in allowances on the international market, effectively capping emissions from electricity generators at 567 million metric tons carbon equivalent per year. The second CO_2 alternative introduced high efficiency assumptions, whereby electricity demand was assumed to be 15 percent lower in 2010 than projected by the industry. Demand was reduced by 1.5 percent annually during the years 2000 to 2010 and by 1 percent annually for the next 10 years. The effective CO_2 emission cap remained at 463 million metric tons carbon equivalent, and the industry was assumed to find it most economical to purchase additional allowances of 52 million metric tons carbon equivalent, yielding a domestic carbon emission cap of 515 million metric tons carbon equivalent for electricity generators.

Costs for controlling Hg emissions were analyzed by assuming that coal-fired generators would install maximum achievable control technology (MACT) in conjunction with either the 50-percent SO_2 reduction or the 515 million metric tons carbon equivalent CO_2 / high efficiency scenario. Two cases considered SO_2 and CO_2 reductions jointly: (1) the 50-percent SO_2 reduction with a CO_2 level of 567 million metric tons carbon equivalent, and (2) the 50-percent SO_2 reduction in combination with a CO_2 level of 515 million metric tons carbon equivalent and high efficiency constraints assumed to reduce demand by 15 percent in 2010.

A key finding of EPA's 1999 analysis was that a joint SO_2-CO_2 reduction strategy would cost the industry less than undertaking the reduction strategies separately. In 2010, reducing SO_2 emissions by 50 percent of the base projection was estimated to cost about $2.5 billion (1990 dollars), and meeting the CO_2 cap of 515 million metric tons carbon equivalent was estimated to cost about $2 billion, with the additional costs resulting from the

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[39] Selective catalytic or noncatalytic reduction.

[40] The ELI study reduces CO_2 emissions indirectly by capping coal-fired generation.

[41] In the EIA analysis cases, the SIP Call modeled applies to 19 States, because since it was first proposed, facilities in Wisconsin have been removed from the program, and the caps on facilities in Missouri and Georgia are under review.

installation of scrubbers, introduction of natural gas combined-cycle technology, and additional dispatch of gas-fired units. Joint reduction lowered the projected aggregate costs to $3.6 billion, or by about 20 percent.[42] The EPA analysis concluded that the industry, when faced with significant CO_2 constraints over and above SO_2 caps, would avoid costly scrubber retrofits and turn to natural gas generation in order to meet SO_2 constraints.

EPRI's Energy-Environment Policy Integration and Coordination Study

The timing and coordination of multiple pollution reduction strategies was the primary focus of EPRI's E-EPIC analysis. Observing that current policy requires power generators to reduce NO_x and SO_2 emissions in the short term, while the Kyoto Protocol calls for significant reductions in CO_2 emissions over the period 2008-2012, EPRI suggested that two key questions should be addressed. First, would the large investments needed to meet the short-term NO_x and SO_2 reductions become "stranded" (unproductive) in the event that additional CO_2 reductions were to be later stipulated? Second, would the combined effects of sequential emission reduction policies lead to significant increases in the price of electricity and other distortions in the national energy system over the longer term to 2050?

EPRI used the NEMS model for the years through 2020 and then extended the NEMS Electricity Market Module to 2050, using other econometric models for projecting energy consumption, prices, and CO_2 emissions. In addition to a reference case,[43] EPRI developed a Current Policy Direction case. Modeling recent proposals addressing NO_x, particulate matter, and CO_2, the Current Policy Direction case imposed a summer NO_x reduction of 85 percent below 1990 levels in 22 States, a subsequent 50-percent reduction in SO_2 emissions by 2007, and a CO_2 emissions target of 9 percent above 1990 levels that would be phased in from 2005 through 2008.[44] In contrast, EPRI's third scenario, the "Carbon Glide Path to 2030" assumed no further NO_x or SO_2 reductions beyond current policy and imposed a gradual CO_2 reduction strategy beginning in 2005, increasing gradually to 2030, resulting in cumulative CO_2 emissions by 2050 that would be the same as in the 9 percent above 1990 case. As such, the Carbon Glide Path did not directly examine the effects of multiple emission reduction strategies.

The conclusions reached in EPRI's E-EPIC analysis differ from those of EPA's 1999 analysis. In the E-EPIC Current Policy Direction case, two-thirds of coal-fired capacity would be retired by 2020, and the coal share of generation would drop from a 2000 level of 55 percent to less than 10 percent by 2020. Nearly 500 gigawatts of gas-fired generating capacity would be added by 2020, with the gas share of total generation rising from 15 percent in 2000 to 60 percent by 2020. Although E-EPIC was tacit on total compliance costs, the study concluded that investment in initial compliance with proposed reductions for SO_2 in the short term would become stranded over the mid-term if CO_2 constraints were subsequently introduced. The study implied that this "inefficiency" could be costly to the electric power industry, and consequently to consumers, both in the short term and in the long term.

Recent Work: "Cleaner Power" Studies

In a recent report issued by Harvard University's John F. Kennedy School, Lee and Verma examined the possible effects of an integrated strategy of emissions reduction in the Midwest.[45] The report identified factors and quantified costs needed to induce coal-fired electricity generators in the Midwest to switch voluntarily from reliance on coal to greater use of natural gas. The authors assumed that coal plants in that region currently operate at just over half the capital and operating cost of a new gas-fired facility. Although the analysis did not cap emissions at specific levels and examined only the rate at which repowering from coal to gas might be induced, the authors reached several conclusions relevant to the EIA, EPA, and EPRI analyses. Their report concluded that the costs associated with reducing NO_x, SO_2, and particulate matter were not high enough to lead to retirements of Midwest coal plants in favor of new natural gas plants. Only the introduction of moderate carbon allowance fees in their analysis made significant amounts of gas-fired generation more attractive than coal-fired generation.

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[42] The IPM calculates total cost as a total resource cost, thereby excluding allowance costs. EIA's analysis in 2010 for the most stringent integrated case includes about $58 billion for purchases of emission allowances in the estimated total compliance cost of $86 billion (in 1999 dollars). Higher projected prices for natural gas account for much of the remaining difference between the EPA and EIA estimates of total compliance costs.

[43] EPRI used the reference case from the EIA's *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), NEMS run AEO99B.D100198A. The case incorporated all environmental regulations in effect as of mid-1998, including Phase II of the Title IV Acid Rain program and EPA's proposed SIP Call summer NO_x reductions for 22 States and the District of Columbia.

[44] EPRI assumed that the remainder of the Kyoto Protocol CO_2 reductions would be met through international carbon permit trading and sequestration. The 9 percent above 1990 level implies CO_2 emissions of about 1,462 million metric tons carbon equivalent in 2010, of which about 409 million metric tons carbon equivalent would be attributable to the electricity generation sector.

[45] H. Lee and S.K. Verma, "Coal or Gas: The Cost of Cleaner Power in the Midwest," BCSIA Discussion Paper 2000-08, ENRP Discussion Paper E-2000-08 (Kennedy School of Government, Harvard University, June 2000).

In order to analyze the rate of conversion from coal to gas, the authors first estimated the marginal cost of abatement for SO_2 and the average abatement costs for NO_x, particulates, and Hg, arriving at a total cost for conventional pollution abatement of about 1 cent per kilowatthour.[46] Assuming a long-term natural gas price of $2.50 per thousand cubic feet, they concluded that a carbon allowance fee of $60 to $70 per ton would prompt about two-thirds of the coal capacity[47] in the Midwest to shift to gas-fired generation. When more favorable gas prices of $2.00 per thousand cubic feet was assumed, a carbon fee between $20 and $30 per ton was expected to induce a two-thirds shift. Gas prices of $3.00 per thousand cubic feet were estimated to require a carbon allowance fee near $150 per ton in order to accomplish the same shift away from coal-fired generation.[48] The authors projected that a carbon allowance fee in the range of $60 to $85 per ton would increase retail electricity prices in the Midwest by 15 to 22 percent, to a range of 10.0 to 10.7 cents per kilowatthour.

The impacts of carbon allowance fees estimated by Lee and Verma are comparable to those in EIA's analysis. In EIA's most stringent integrated case, cumulative coal retirements nationally are projected to reach 47 gigawatts by 2010, about 15 percent of current coal capacity, with a corresponding carbon allowance fee of $134 per ton and a projected gas price of $4.33 per thousand cubic feet in 2010. Lee and Verma indicate that a combination of high gas prices ($3.00 per thousand cubic feet) and efficient conventional coal retrofits would force the conversion of 21 to 30 percent of coal-fired generating resources,[49] indicating a carbon allowance fee between $120 and $130 per ton.

A recent report from the Environmental Law Institute (ELI) arrived at findings similar to those of Lee and Verma. Using the Haiku Electricity Market Module[50] developed and maintained by Resources for the Future, ELI modeled a scenario in which coal-fired generation was reduced by 25 percent in 2005 and by an additional 25 percent by 2010, replacing the generation with electricity from gas-fired turbines and combined-cycle units.[51] The shift in generation produced dramatic changes in emission patterns, reducing SO_2 by 51 percent, NO_x by 40 percent, and CO_2 by 26 percent in 2010.[52]

ELI's analysis projected that the retail price of electricity would rise by 0.6 cents, to 6.63 cents per kilowatthour (1997 dollars), leading to total economic costs, mostly lost consumer surplus, estimated at $25.9 billion (1997 dollars) in 2010.[53] Total electricity generation was projected to grow modestly over the 1998-2010 forecast period but was projected to fall slightly in the policy case from the "business as usual," or reference, case. Total nameplate coal-fired generating capacity was projected to decline by about 9 percent, to 293 gigawatts in 2010, indicating that decreased capacity utilization rates for coal plants would not necessarily render them uneconomical. Natural gas prices were projected to increase by 21 percent in the policy case, with prices in 2010 climbing from $3.30 per million Btu in the reference case to $4.00 per million Btu in the policy case.[54] The report underscores the finding that integrated approaches to emission reductions offer significant efficiencies.

Reference Case Comparisons

Reference case results for the four studies examined here show reasonably similar starting points (Table 22).[55] In both the EPA and EPRI studies, the reference cases were calibrated to earlier versions of EIA's *Annual Energy Outlook*. EPRI used the *Annual Energy Outlook 1999* reference case, and EPA used the *Annual Energy Outlook 1998*. Projections of coal-fired capacity in 2005 are nearly identical, ranging from a high of 319 gigawatts in ELI's reference case to 303 gigawatts in the EPRI and ELI Business As Usual cases. In EPRI's Business As Usual case, coal capacity is projected to increase slightly by 2010, but in EPA's 1999 reference case it declines slightly. Projections of coal-fired generation are fairly divergent, ranging from a low of 1,770 billion kilowatthours in 2005 in ELI's reference case to a high figure of 2,156 in EIA's reference case. ELI's reference case, however, projects the lowest

[46] The authors put the upper bound at 1.36 cents per kilowatthour and the lower bound at 0.68 cents per kilowatthour (in 1998 dollars).

[47] Current coal capacity in East Central Area Reliability (ECAR) is about 84 gigawatts, suggesting a shift of about 56 gigawatts to gas.

[48] The high and low sensitivities incorporated the respective assumptions regarding high and low costs of conventional pollution abatement.

[49] In EIA's analysis, some reductions are projected to be achieved by building new renewable sources of generation, a factor not addressed in the Cleaner Power studies.

[50] Like NEMS, Haiku models some North American Electric Reliability Council regions as competitive; only in these regions are tradeable generation permits allowed.

[51] Small amounts of additional wind capacity were also projected.

[52] Reduced Hg levels were also projected in the ELI policy case, to 21 tons in 2010, or about a 75-percent reduction from the 1998 baseline of 80 tons.

[53] The analysis also identified $26.4 billion in public health benefits from reductions in SO_2 and NO_x as a result of lower particulate concentrations.

[54] In 1999, natural gas deliveries to electric utilities averaged 1,022 Btu per cubic foot; corresponding prices per thousand cubic feet would be about 2 percent lower.

[55] The study by Lee and Verma was regional in scope, preventing national comparisons.

Table 22. Key Reference Case Projections for Electricity Generation in Four Multi-Emission Studies, 2005, 2007, and 2010

Projection	EIA Reference Case			EPA 1999 Reference Case			EPRI E-EPIC Business As Usual Case			ELI Business As Usual Case	
	2005	2007	2010	2005	2007	2010	2005	2007	2010	2005	2010
Coal-Fired Capacity (Gigawatts)	302	312	317	305	304	301	303	303	305	319	321
Electricity Generation by Fuel (Billion Kilowatthours)											
Coal	2,156	2,235	2,284	2,084	2,091	2,114	2,052	2,065	2,096	1,770	1,805
Natural Gas	813	907	1,123	561	626	759	838	1,006	1,175	1,056	1,267
Nuclear	740	738	720	609	613	580	627	587	551	670	683
Renewables[a]	97	108	125	61	61	61	61	62	66	35	39
Electricity Demand (Billion Kilowatthours)	3,762	3,919	4,146	3,612	3,690	3,809	3,578	3,702	3,859	3,863	4,121
Electricity Price (1999 Cents per Kilowatthour)	6.2	6.0	5.9	NA	NA	NA	6.3	6.1	6.0	6.5	6.1
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.49	2.60	2.68	2.05	2.05	2.05	2.41	2.52	2.61	NA	3.37
Coal Minemouth Price (1999 Dollars per Short Ton)	14.76	14.23	13.69	NA	NA	NA	15.39	15.01	14.47	NA	NA
Carbon Dioxide Emissions (Million Metric Tons Carbon Equivalent)	637	658	686	605	615	621	620	634	657	652	671
Sulfur Dioxide Emissions (Million Tons)	10.4	10.1	9.7	11.0	10.9	9.7	10.5	9.8	9.2	10.1	9.0
Nitrogen Oxide Emissions (Million Tons)	4.22	4.19	4.20	4.22	4.25	4.15	3.99	4.03	4.10	5.52	5.52

[a] Excludes hydroelectric generation.

NA = not available.

Sources: **EIA:** National Energy Modeling System, run MCBASE.D121300A. **EPA:** U.S. Environmental Protection Agency, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), run HGIPM9C. **EPRI:** Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study: Executive Report* (Washington, DC, April 2000), run Business As Usual. **ELI:** Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000), run Business As Usual.

coal share of generation in 2005, about 46 percent of total generation. Coal's share of generation is projected to stay about the same in each of the four cases from 2005 through 2010.

Projections of generation from natural gas in 2005 vary significantly in the reference cases, ranging from 561 billion kilowatthours in EPA's reference case[56] to 1,056 billion kilowatthours in ELI's study. The share of generation from gas, however, is projected to increase in all of the studies by 2010. ELI's share of gas generation expands the least, as both EIA and EPRI projections of gas generation grow at a faster rate. Gas-fired generation in the ELI reference case is substantially higher than in the other studies, especially EPA's 1999 reference case, which ELI exceeds by 495 billion kilowatthours in 2005 and by 508 billion kilowatthours in 2010.

Projections of nuclear generation exhibit widely disparate baselines in 2005, with EIA projecting 740 billion kilowatthours, EPA 609 billion kilowatthours, EPRI projecting 627 billion kilowatthours, and ELI 670 billion kilowatthours. All the studies except ELI project declining generation from nuclear sources, a trend that is most pronounced in the EPRI study, at about 12 percent by 2010.

Generation from nonhydroelectric renewable sources shows the largest response in the EIA reference case, with a projected increase from 97 billion kilowatthours in 2005 to 125 billion kilowatthours in 2010. Renewable generation increases in both the EPRI and ELI reference cases, from 61 billion kilowatthours to 66 billion kilowatthours in the former and from 35 billion kilowatthours to 39 billion kilowatthours in the latter. EPA's reference case projects no increase in renewable generation over the forecast period.

Electricity demand rises in all four reference cases, led by a 10-percent increase in the EIA study, with both EPRI and ELI projecting about a 7-percent increase and EPA a 5-percent increase. The average projected electricity price falls by similar amounts in the three studies that report prices,[57] in part because coal prices are projected to decline over the 2005-2010 period. Gas prices are projected to rise and coal prices are projected to fall across

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[56] Includes generation from dual-fired facilities not otherwise specified.

[57] EPA's 1999 analysis does not report end-use prices.

all the studies. CO_2 emissions are projected to increase in all the reference cases, with EIA projecting the largest increase over the 2005-2010 period at just over 7 percent.

Comparison of Integrated Cases

In the cases that assume integrated multi-emission reduction strategies, the electric power industry is projected to respond with similar changes in the four studies. All the integrated cases project reduced coal capacity, reduced generation from coal, and increased generation from natural gas (Table 23). In three of the studies, gas prices are projected to rise over the relevant forecast horizon, and coal prices are projected to fall. EPA's analysis does not model a fuel price response.

Differences in the assumed CO_2 emission targets account for some of the differences in the projected industry response. From a reference case projection of 686 million metric tons carbon equivalent, EIA's integrated 1990-7% 2005 case assumes a reduction to 443 million metric tons carbon equivalent by 2010. EPRI's Current Policy Direction case assumes CO_2 emissions of 399 million metric tons carbon equivalent by 2010. The CO_2 targets of 567 million metric tons carbon equivalent and 515 million metric tons carbon equivalent in EPA's 1999 analysis are significantly more lenient.[58] Both the EIA and EPRI studies include a carbon allowance fee, but their emission targets are different. EPA's 1999 analysis did not report a carbon allowance fee.

The integrated cases in the four studies indicate that when CO_2 emissions are significantly reduced, the need to address directly the remaining emissions, NO_x and SO_2, is mitigated. In EIA's study, NO_x reductions of 75 percent below 1997 levels are projected to be achieved with far fewer NO_x equipment retrofits (only 197 gigawatts, compared with 312 gigawatts in the NO_x 2005 case). SO_2 equipment retrofits are projected to be 10 gigawatts in 2010 in EIA's integrated 1990-7% 2005 case, compared with 98 gigawatts in the SO_2 2005 case. The integrated cases in EPA's 1999 analysis indicate a similar industry response. Projected NO_x retrofits fall in the integrated cases relative to those in the NO_x only cases. Similarly, EPA projects greatly reduced need for scrubbers in the integrated cases, falling by more than half from 93 gigawatts in the 55-percent SO_2 reduction case to 45 gigawatts in the integrated 50-percent SO_2 reduction and the 515 million metric ton CO_2 reduction case.

The EIA study projects the greatest reduction in coal-fired capacity, from the reference case projection of 317 gigawatts in 2010 to 260 gigawatts in the integrated 1990-7% 2005 case in 2010. The EPA study, which projects steady levels of coal capacity when SO_2 constraints alone are assumed, projects about an 8-percent reduction in coal capacity to 279 gigawatts in 2010 when CO_2 emissions are capped at 515 million metric tons carbon equivalent. The EPRI study projects that coal capacity would fall by about 35 gigawatts from the reference level in 2010 in the Current Policy Direction case.

Coal-fired electricity generation is projected to decline in the integrated cases in all the studies, but the reductions vary in both magnitude and timing. In the EPA study, which projects far more coal-fired generation in its most stringent case than do the other studies, coal-fired generation still is projected to decline by 461 billion kilowatthours by 2010, to 1,653 billion kilowatthours. The EIA study projects a decline of more than half, and EPRI projects a drop of about 59 percent by 2010 in the Current Policy Direction case, virtually all of which occurs between 2005 and 2010.[59] Natural gas generation is projected to address most of the shortfall in coal-fired generation in all four studies. Renewable generation is projected to increase in all the studies except EPA's, and nuclear generation is projected to increase above reference levels in the EIA and EPRI studies.

Electricity demand is projected to be reduced in three of the studies, by about 8 percent in EIA's most stringent case, by about 7 percent in EPRI's Current Policy Direction case, and by about 2 percent in the ELI study. EPA's study does not model an endogenous demand response. Projected electricity prices are much higher in both the EIA and EPRI analyses, and a more moderate price increase is projected in the ELI study. EIA projects an electricity price of 8.4 cents per kilowatthour in 2010 in the integrated 1990-7% 2005 case, an increase of about 42 percent from the reference case projection. EPRI's Current Policy Direction case projects an average electricity price of 8.4 cents per kilowatthour in 2010, about a 37-percent increase over the reference level. In contrast, ELI projects a smaller increase of about 11 percent, to 6.8 cents per kilowatthour, an increase that only partially reflects the full cost of the coal phaseout, due to assumed efficiency gains from industry restructuring. Electricity prices are not reported in the EPA study.

In summary, although the four studies discussed in this chapter examine the impacts of efforts to reduce power sector emissions, they assume different emission targets and use different analysis approaches. As a result, it is difficult to compare the specific results of the studies. The general results are similar, however. All the studies find that efforts to reduce power plant emissions, particularly CO_2, would be expected to lead to a shift from

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[58] Although it is not an integrated emission reduction scenario, ELI's cap on coal-fired generation results in significant reductions in projected CO_2 emissions, from 671 million metric tons carbon equivalent to 499 in 2010.

[59] ELI imposed a 50-percent reduction on coal-fired generation as the constraint.

Table 23. Key Projections for Integrated Emission Reduction Cases in Four Multi-Emission Reduction Studies, 2005 and 2010

	EIA			EPA		
Projection	Reference	Integrated 1990-7% 2005	Integrated 1990-7% 2008	Reference	50% SO_2 and CO_2 567 MMT	50% SO_2 and CO_2 515 MMT[a]
2005 Projections						
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	637	473	536	605	602	593
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	113	71	NA	NA	NA
NO_x Retrofits (Gigawatts)	110	196	60	199	196	194
SO_2 Retrofits (Gigawatts)	11	10	12	4	44	38
Coal-Fired Capacity (Gigawatts)	302	299	300	304	303	301
Electricity Generation by Fuel (Billion Kilowatthours)						
Coal	2,156	1,347	1,695	2,084	2,051	2,038
Natural Gas	813	1,367	1,098	561	586	526
Nuclear	740	740	740	609	609	609
Renewables[b]	97	166	174	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.49	3.46	2.85	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.76	13.07	13.70	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	3,762	3,564	3,648	3,612	3,612	3,539
Electricity Price (1999 Cents per Kilowatthour)	6.2	8.1	7.2	NA	NA	NA
SO_2 Emissions (Million Tons)	10.4	4.9	8.2	11.0	7.0	7.3
NO_x Emissions (Million Tons)	4.22	1.46	2.74	4.22	4.19	4.17
2010 Projections						
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	686	443	430	621	567	515
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	134	126	NA	NA	NA
NO_x Retrofits (Gigawatts)	115	197	146	209	200	190
SO_2 Retrofits (Gigawatts)	0	10	12	6	63	45
Coal-Fired Capacity (Gigawatts)	317	260	265	303	294	279
Electricity Generation by Fuel (Billion Kilowatthours)						
Coal	2,284	1,135	1,067	2,114	1,812	1,653
Natural Gas	1,123	1,839	1,935	759	1,054	972
Nuclear	720	741	741	580	580	580
Renewables[b]	125	253	254	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.68	4.33	4.16	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	13.69	11.82	12.03	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	4,146	3,832	3,868	3,809	3,809	3,568
Electricity Price (1999 Cents per Kilowatthour)	5.9	8.4	8.2	NA	NA	NA
SO_2 Emissions (Million Tons)	9.7	3.9	4.0	9.7	4.6	4.5
NO_x Emissions (Million Tons)	4.20	1.30	1.32	4.15	3.52	3.15

[a] Includes high efficiency assumptions.

[b] Excludes hydroelectric generation.

NA = not available.

Note: See Table 22 for EPA and EPRI reference case results.

Case constraints: **EIA:** CO_2 reductions to 1990 levels met in either 2005 or 2008, with CO_2 7% below 1990 level by 2010, NO_x 75% below 1997, and SO2 75% below 1997. **EPA:** carbon emissions capped at 567 MMT by 2008, and SO_2 emissions capped at 50% of CAAA by 2010; and carbon emissions capped at 515 MMT in 2008, and SO_2 emissions capped at 50% of CAAA and electricity demand reduced gradually beginning in 2001. Retrofits include units with both NO_x and SO_2 reduction technology. **EPRI:** Current Policy Direction—50% SO_2 reduction by 2007, CO_2 capped at 9% above 1990 in 2005-2008, constant thereafter; Carbon Glide—SO_2 emissions capped at 8.95 million metric tons carbon equivalent, CO_2 restrictions imposed in 2005, gradually increasing to 2030, so that cumulative CO_2 emissions by 2050 equal those obtained in Current Policy Direction case. **ELI:** coal-fired generation reduced by 25% from baseline (1998) levels by 2005, and by 50% from baseline by 2010.

Sources: **EIA:** National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, and FDP7B08.D121500A. **EPA:** U.S. Environmental Protection Agency, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), runs HGIPM18B and HGIPM11C. **EPRI:** Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study: Executive Report* (Washington, DC, April 2000), runs Current Policy Direction and Carbon Glidepath. **ELI:** Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000), runs "Business as Usual" and "Coal Reduction."

Table 23. Key Projections for Integrated Emission Reduction Cases in Four Multi-Emission Reduction Studies, 2005 and 2010 (Continued)

Projection	EPRI			ELI	
	Business As Usual	Current Policy Direction	Carbon Glide	Business As Usual	50% Coal Reduction
2005 Projections					
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	620	588	581	652	558
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	12	25	NA	NA
NO_x Retrofits (Gigawatts)	179	133	149	NA	NA
SO_2 Retrofits (Gigawatts)	12	0	0	NA	NA
Coal-Fired Capacity (Gigawatts)	303	286	290	319	308
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,052	1,874	1,854	1,770	1,327
Natural Gas	838	985	971	1,056	1,288
Nuclear	627	661	661	670	673
Renewables[b]	61	64	63	35	63
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.41	2.51	2.48	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	15.39	15.12	15.24	NA	NA
Electricity Demand (Billion Kilowatthours)	3,578	3,577	3,541	3,863	3,690
Electricity Price (1999 Cents per Kilowatthour)	6.5	6.6	6.9	6.5	6.8
SO_2 Emissions (Million Tons)	10.5	10.4	10.2	10.1	7.7
NO_x Emissions (Million Tons)	3.99	3.92	3.85	5.52	4.43
2010 Projections					
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	657	399	482	671	499
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	116	56	NA	NA
NO_x Retrofits (Gigawatts)	185	133	149	NA	NA
SO_2 Retrofits (Gigawatts)	18	0	0	NA	NA
Coal-Fired Capacity (Gigawatts)	305	269	276	321	293
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,096	854	1,251	1,805	889
Natural Gas	1,175	1,943	1,690	1,267	2,061
Nuclear	551	623	623	683	685
Renewables[b]	66	157	208	39	92
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.61	3.30	2.93	3.37	4.09
Coal Minemouth Price (1999 Dollars per Ton)	14.47	16.13	15.43	NA	NA
Electricity Demand (Billion Kilowatthours)	3,859	3,587	3,732	4,121	4,051
Electricity Price (1999 Cents per Kilowatthour)	6.1	8.4	7.2	6.1	6.8
SO_2 Emissions (Million Tons)	9.2	4.5	4.4	9.0	4.4
NO_x Emissions (Million Tons)	9.23	2.26	2.86	5.52	3.30

coal-fired generation to natural-gas-fired generation. In addition, they find that efforts to reduce CO_2 emissions would have the largest impacts, reducing the need to invest in equipment to mitigate NO_x and SO_2 emissions and making it easier, or less costly, to meet SO_2 and NO_x constraints. Generally, the studies estimate that compliance costs would vary directly with the stringency of the emission targets. Finally, the studies are in agreement that meeting combined constraints would ultimately cost less than meeting a series of individual constraints.

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Appendix A

Tables for NO_x Cap Cases

Table A1. 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 Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.85	11.85	10.90	10.89	10.89	10.61	10.65	10.65
Natural Gas Plant Liquids	2.62	3.02	3.00	3.01	3.31	3.34	3.34	4.07	4.08	4.09
Dry Natural Gas	19.16	21.26	21.15	21.22	23.63	23.81	23.82	29.59	29.65	29.71
Coal	23.12	25.43	25.29	25.22	26.47	25.95	25.98	27.21	26.89	26.83
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.17	6.17
Renewable Energy[1]	6.50	6.98	6.99	7.00	7.65	7.62	7.63	8.20	8.17	8.18
Other[2]	1.65	0.57	0.59	0.57	0.33	0.42	0.30	0.33	0.33	0.33
Total	**73.30**	**77.01**	**76.78**	**76.77**	**79.98**	**79.72**	**79.65**	**86.18**	**85.93**	**85.95**
Imports										
Crude Oil[3]	18.96	23.21	23.16	23.19	25.22	25.14	25.13	26.48	26.46	26.46
Petroleum Products[4]	4.14	4.85	4.85	4.84	6.46	6.44	6.51	10.77	10.74	10.71
Natural Gas	3.63	4.90	4.93	4.94	5.49	5.58	5.58	6.60	6.68	6.68
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**	**34.08**	**34.06**	**34.09**	**38.12**	**38.11**	**38.18**	**44.82**	**44.84**	**44.80**
Exports										
Petroleum[6]	1.98	1.81	1.81	1.81	1.79	1.78	1.78	1.90	1.91	1.90
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**	**3.64**	**3.64**	**3.64**	**3.67**	**3.66**	**3.66**	**3.94**	**3.95**	**3.94**
Discrepancy[7]	**0.95**	**0.39**	**0.38**	**0.39**	**0.21**	**0.22**	**0.19**	**-0.03**	**-0.03**	**-0.02**
Consumption										
Petroleum Products[8]	38.07	41.40	41.34	41.37	44.43	44.42	44.42	50.60	50.60	50.58
Natural Gas	21.90	25.78	25.72	25.77	28.52	28.78	28.80	35.40	35.52	35.60
Coal	21.46	24.37	24.24	24.16	25.54	25.06	25.05	26.48	26.14	26.06
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.17	6.17
Renewable Energy[1]	6.51	6.98	7.00	7.01	7.66	7.62	7.64	8.21	8.17	8.18
Other[9]	0.35	0.61	0.61	0.61	0.38	0.38	0.38	0.25	0.25	0.25
Total	**96.09**	**107.05**	**106.82**	**106.83**	**114.21**	**113.96**	**113.97**	**127.10**	**126.86**	**126.84**
Net Imports - Petroleum	**21.12**	**26.26**	**26.20**	**26.23**	**29.88**	**29.80**	**29.86**	**35.36**	**35.30**	**35.27**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	2.47	2.49	2.68	2.68	2.72	3.14	3.18	3.15
Coal Minemouth Price (dollars per ton)	17.23	14.76	14.88	14.82	13.69	13.99	13.94	12.84	12.94	12.95
Average Electric Price (cents per Kwh)	6.6	6.2	6.2	6.2	5.9	5.9	5.9	6.0	6.0	6.0

[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.

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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.88	0.88	0.81	0.81	0.81	0.75	0.75	0.75
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	0.41	0.41	0.41	0.39	0.40	0.39
Petroleum Subtotal	1.42	1.42	1.42	1.42	1.29	1.29	1.29	1.21	1.21	1.21
Natural Gas	4.85	5.46	5.47	5.46	5.69	5.70	5.69	6.30	6.30	6.30
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	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44
Electricity	3.91	4.50	4.49	4.49	4.96	4.94	4.95	5.80	5.78	5.79
Delivered Energy	**10.62**	**11.86**	**11.86**	**11.85**	**12.42**	**12.41**	**12.41**	**13.80**	**13.78**	**13.79**
Electricity Related Losses	8.46	9.46	9.38	9.38	9.88	9.80	9.81	10.58	10.51	10.50
Total	**19.08**	**21.32**	**21.24**	**21.24**	**22.30**	**22.21**	**22.22**	**24.38**	**24.29**	**24.29**
Commercial										
Distillate Fuel	0.36	0.41	0.41	0.41	0.41	0.41	0.41	0.39	0.39	0.39
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.66	0.66	0.67	0.67	0.67	0.66	0.66	0.66
Natural Gas	3.15	3.71	3.72	3.72	3.89	3.88	3.88	4.12	4.12	4.12
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.34	4.34	4.89	4.87	4.88	5.61	5.60	5.60
Delivered Energy	**7.59**	**8.87**	**8.87**	**8.87**	**9.60**	**9.58**	**9.58**	**10.55**	**10.53**	**10.54**
Electricity Related Losses	8.00	9.15	9.08	9.08	9.74	9.67	9.68	10.23	10.17	10.15
Total	**15.59**	**18.02**	**17.95**	**17.95**	**19.34**	**19.25**	**19.25**	**20.79**	**20.70**	**20.69**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.13	1.13	1.27	1.27	1.27	1.44	1.45	1.44
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.50	2.50	2.50	2.83	2.84	2.83
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.22	0.22	0.22	0.25	0.25	0.25	0.27	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	4.49	4.47	4.49	4.76	4.76	4.75	5.25	5.25	5.24
Petroleum Subtotal	9.39	9.95	9.92	9.94	10.55	10.55	10.55	11.78	11.79	11.77
Natural Gas[6]	9.43	10.42	10.45	10.43	11.11	11.13	11.12	12.33	12.34	12.35
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.82	1.82	1.85	1.85	1.86	1.89	1.90	1.90
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	2.62	2.63	2.63	2.61	2.62	2.62	2.62	2.62	2.62
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.63	3.90	3.90	3.90	4.19	4.17	4.18	4.81	4.80	4.80
Delivered Energy	**27.15**	**29.32**	**29.31**	**29.32**	**31.10**	**31.11**	**31.11**	**34.62**	**34.63**	**34.63**
Electricity Related Losses	7.85	8.22	8.15	8.15	8.34	8.27	8.29	8.78	8.72	8.71
Total	**35.00**	**37.53**	**37.46**	**37.47**	**39.45**	**39.38**	**39.39**	**43.40**	**43.35**	**43.33**

Table A2. 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 Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Transportation										
Distillate Fuel	5.13	6.28	6.27	6.27	6.99	6.98	6.99	8.21	8.20	8.20
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	17.70	17.70	17.70	19.05	19.04	19.04	21.32	21.32	21.32
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	0.04	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	29.06	29.05	31.75	31.74	31.73	36.77	36.76	36.76
Pipeline Fuel Natural Gas	0.66	0.77	0.76	0.77	0.89	0.89	0.90	1.08	1.08	1.09
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	0.00	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**	**29.99**	**29.99**	**29.99**	**32.89**	**32.88**	**32.88**	**38.23**	**38.22**	**38.22**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.23	0.23	0.30	0.30	0.30
Total	**26.41**	**30.18**	**30.17**	**30.18**	**33.12**	**33.12**	**33.11**	**38.53**	**38.52**	**38.52**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.70	8.70	9.47	9.46	9.47	10.80	10.79	10.79
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	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	3.03	3.03	3.03	3.05	3.05	3.05	3.38	3.39	3.38
Motor Gasoline[2]	16.17	17.96	17.96	17.96	19.32	19.32	19.31	21.63	21.63	21.62
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.17	1.17	1.17	1.21	1.21	1.21	1.25	1.25	1.25
Other Petroleum[12]	4.53	4.76	4.74	4.76	5.04	5.04	5.04	5.58	5.58	5.57
Petroleum Subtotal	36.95	41.08	41.05	41.08	44.26	44.25	44.24	50.42	50.42	50.40
Natural Gas[6]	18.11	20.42	20.46	20.43	21.67	21.70	21.67	24.00	24.00	24.02
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.94	1.94	1.98	1.98	1.98	2.02	2.02	2.02
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	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.75	2.75
Renewable Energy[13]	2.65	2.95	2.95	2.95	3.19	3.19	3.19	3.65	3.65	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.82	12.82	14.15	14.10	14.12	16.39	16.34	16.35
Delivered Energy	**71.65**	**80.04**	**80.03**	**80.03**	**86.01**	**85.98**	**85.97**	**97.20**	**97.17**	**97.18**
Electricity Related Losses	24.44	27.02	26.79	26.79	28.20	27.97	28.01	29.89	29.69	29.66
Total	**96.09**	**107.05**	**106.82**	**106.83**	**114.21**	**113.96**	**113.97**	**127.10**	**126.86**	**126.84**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
Residual Fuel	1.07	0.27	0.24	0.25	0.13	0.13	0.14	0.14	0.14	0.14
Petroleum Subtotal	1.13	0.32	0.29	0.29	0.17	0.17	0.18	0.19	0.18	0.18
Natural Gas	3.79	5.36	5.27	5.34	6.84	7.09	7.13	11.40	11.52	11.57
Steam Coal	18.81	21.63	21.49	21.42	22.80	22.32	22.31	23.73	23.40	23.32
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.17	6.17
Renewable Energy[15]	3.86	4.03	4.05	4.05	4.47	4.44	4.45	4.56	4.52	4.53
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**35.73**	**39.85**	**39.61**	**39.62**	**42.35**	**42.08**	**42.13**	**46.28**	**46.03**	**46.01**

Table A2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.74	8.74	9.51	9.50	9.51	10.84	10.84	10.84
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	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	3.03	3.03	3.03	3.05	3.05	3.05	3.38	3.39	3.38
Motor Gasoline[2]	16.17	17.96	17.96	17.96	19.32	19.32	19.31	21.63	21.63	21.62
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.12	1.44	1.42	1.42	1.34	1.34	1.34	1.39	1.38	1.38
Other Petroleum[12]	4.53	4.76	4.74	4.76	5.04	5.04	5.04	5.58	5.58	5.57
Petroleum Subtotal	38.07	41.40	41.34	41.37	44.43	44.42	44.42	50.60	50.60	50.58
Natural Gas	21.90	25.78	25.72	25.77	28.52	28.78	28.80	35.40	35.52	35.60
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.65	23.57	23.43	23.36	24.77	24.30	24.29	25.75	25.42	25.34
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	21.46	24.37	24.24	24.16	25.54	25.06	25.05	26.48	26.14	26.06
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.17	6.17
Renewable Energy[17]	6.51	6.98	7.00	7.01	7.66	7.62	7.64	8.21	8.18	8.19
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.37	0.37	0.24	0.24	0.24
Total	**96.09**	**107.05**	**106.82**	**106.83**	**114.21**	**113.96**	**113.97**	**127.10**	**126.86**	**126.84**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	80.03	80.03	86.01	85.98	85.97	97.20	97.17	97.18
Total Energy Use	96.09	107.05	106.82	106.83	114.21	113.96	113.97	127.10	126.86	126.84
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	1694.3	1689.0	1688.1	1816.2	1807.3	1807.3	2045.4	2038.7	2037.2

[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 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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A3. 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 Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Residential	**13.12**	**12.91**	**12.92**	**12.93**	**13.15**	**13.22**	**13.25**	**13.59**	**13.65**	**13.63**
Primary Energy[1]	6.72	7.12	7.10	7.11	7.00	6.99	7.05	7.02	7.06	7.04
Petroleum Products[2]	7.55	9.18	9.18	9.18	9.37	9.23	9.38	9.66	9.65	9.65
Distillate Fuel	6.27	7.34	7.34	7.33	7.51	7.48	7.51	7.99	7.99	7.98
Liquefied Petroleum Gas	10.36	12.83	12.82	12.82	13.06	12.68	13.08	12.90	12.88	12.90
Natural Gas	6.52	6.63	6.61	6.62	6.52	6.53	6.57	6.56	6.60	6.58
Electricity	23.46	21.84	21.93	21.93	21.88	22.10	22.08	22.16	22.28	22.25
Commercial	**13.20**	**12.36**	**12.40**	**12.41**	**11.74**	**11.82**	**11.87**	**12.37**	**12.46**	**12.43**
Primary Energy[1]	5.22	5.35	5.34	5.35	5.53	5.52	5.56	5.76	5.79	5.77
Petroleum Products[2]	5.00	6.01	6.01	6.01	6.17	6.10	6.17	6.52	6.50	6.50
Distillate Fuel	4.37	5.13	5.13	5.12	5.28	5.26	5.28	5.77	5.75	5.75
Residual Fuel	2.63	3.64	3.64	3.64	3.69	3.69	3.69	3.85	3.85	3.85
Natural Gas[3]	5.34	5.31	5.29	5.30	5.49	5.50	5.54	5.72	5.76	5.73
Electricity	21.43	19.51	19.63	19.63	17.61	17.80	17.84	18.09	18.24	18.22
Industrial[4]	**5.32**	**5.49**	**5.48**	**5.49**	**5.44**	**5.39**	**5.48**	**5.85**	**5.88**	**5.87**
Primary Energy	3.92	4.25	4.23	4.24	4.37	4.30	4.39	4.73	4.74	4.73
Petroleum Products[2]	5.55	5.95	5.94	5.94	6.05	5.89	6.06	6.28	6.27	6.28
Distillate Fuel	4.65	5.29	5.29	5.29	5.46	5.43	5.46	5.98	5.95	5.95
Liquefied Petroleum Gas	8.50	7.94	7.93	7.93	8.00	7.59	8.01	7.86	7.84	7.86
Residual Fuel	2.78	3.37	3.36	3.36	3.42	3.42	3.42	3.58	3.58	3.58
Natural Gas[5]	2.79	3.17	3.15	3.16	3.30	3.29	3.33	3.77	3.81	3.79
Metallurgical Coal	1.65	1.58	1.58	1.58	1.54	1.54	1.55	1.44	1.44	1.44
Steam Coal	1.43	1.34	1.34	1.34	1.29	1.30	1.30	1.21	1.21	1.21
Electricity	13.01	12.30	12.34	12.35	11.21	11.33	11.40	11.60	11.72	11.71
Transportation	**8.30**	**9.27**	**9.26**	**9.26**	**9.45**	**9.45**	**9.47**	**9.32**	**9.31**	**9.32**
Primary Energy	8.29	9.25	9.25	9.24	9.44	9.44	9.46	9.30	9.29	9.30
Petroleum Products[2]	8.28	9.25	9.24	9.24	9.44	9.44	9.45	9.30	9.29	9.29
Distillate Fuel[6]	8.22	8.89	8.89	8.88	8.94	8.94	8.94	9.02	8.98	8.99
Jet Fuel[7]	4.70	5.24	5.25	5.23	5.46	5.46	5.47	5.88	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.63	10.63	10.92	10.93	10.95	10.68	10.68	10.68
Residual Fuel	2.46	3.10	3.10	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.17	14.18	14.24	13.92	14.29	13.88	13.86	13.88
Natural Gas[10]	7.02	6.80	6.77	6.79	7.03	7.05	7.08	7.33	7.37	7.34
Ethanol (E85)[11]	14.42	19.12	19.08	19.07	19.00	19.00	19.01	19.36	19.37	19.36
Methanol (M85)[12]	10.38	13.11	12.99	13.12	13.74	13.73	13.74	14.43	14.43	14.43
Electricity	15.58	14.29	14.34	14.24	13.53	13.70	13.56	13.03	13.17	13.12
Average End-Use Energy	**8.53**	**8.90**	**8.91**	**8.91**	**8.94**	**8.94**	**8.99**	**9.17**	**9.20**	**9.19**
Primary Energy	6.33	7.00	6.99	6.99	7.18	7.15	7.20	7.31	7.32	7.32
Electricity	19.40	18.10	18.18	18.19	17.18	17.36	17.38	17.57	17.70	17.68
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	1.49	1.50	1.52	1.55	1.56	1.85	1.89	1.88
Petroleum Products	2.50	3.70	3.68	3.68	4.06	4.07	4.07	4.33	4.35	4.35
Distillate Fuel	4.04	4.65	4.64	4.64	4.85	4.81	4.83	5.30	5.28	5.28
Residual Fuel	2.41	3.52	3.49	3.50	3.85	3.84	3.84	4.04	4.06	4.06
Natural Gas	2.54	2.89	2.84	2.85	3.02	3.01	3.05	3.61	3.67	3.65
Steam Coal	1.22	1.13	1.13	1.13	1.05	1.06	1.06	0.98	0.99	0.99

Table A3. 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$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.43	8.43	8.63	8.59	8.64	8.62	8.61	8.62
Distillate Fuel	7.27	8.07	8.07	8.06	8.18	8.17	8.18	8.41	8.38	8.38
Jet Fuel	4.70	5.24	5.25	5.23	5.46	5.46	5.47	5.88	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.83	8.83	8.87	8.47	8.89	8.64	8.63	8.65
Motor Gasoline[8]	9.45	10.64	10.63	10.63	10.92	10.92	10.95	10.68	10.68	10.68
Residual Fuel	2.48	3.26	3.25	3.25	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.05	4.25	4.23	4.24	4.27	4.25	4.29	4.52	4.56	4.54
Coal	1.24	1.15	1.15	1.15	1.07	1.08	1.08	1.00	1.01	1.01
Ethanol (E85)[11]	14.42	19.12	19.08	19.07	19.00	19.00	19.01	19.36	19.37	19.36
Methanol (M85)[12]	10.38	13.11	12.99	13.12	13.74	13.73	13.74	14.43	14.43	14.43
Electricity	19.40	18.10	18.18	18.19	17.18	17.36	17.38	17.57	17.70	17.68
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	147.68	147.78	157.75	158.34	158.75	181.60	182.19	182.01
Commercial	99.10	108.63	108.98	109.04	111.63	112.29	112.70	129.48	130.17	130.02
Industrial	110.62	121.27	121.17	121.31	126.35	125.43	127.42	151.05	151.78	151.62
Transportation	212.64	270.40	270.29	270.19	301.90	301.82	302.30	345.30	344.98	345.09
Total Non-Renewable Expenditures	556.41	647.83	648.12	648.32	697.64	697.88	701.16	807.43	809.13	808.73
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.61	0.61	0.62	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**648.54**	**648.74**	**698.25**	**698.49**	**701.78**	**808.29**	**809.99**	**809.59**

[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 MCBASE.D082400A, MCNOX05.D082400A, and MCNOX08.D082500A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D082400A, MCNOX05.D082400A, and MCNOX08.D082500A, **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	2094	2087	2232	2185	2185	2317	2283	2276
Petroleum	104	32	29	30	18	18	18	19	19	19
Natural Gas[2]	365	574	580	588	867	903	906	1568	1590	1598
Nuclear Power	730	740	740	740	720	720	720	577	577	577
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	363	363	384	383	384	390	389	389
Total	**3386**	**3811**	**3805**	**3806**	**4220**	**4208**	**4212**	**4872**	**4857**	**4859**
Non-Utility Generation for Own Use	16	16	16	16	16	16	16	16	16	16
Distributed Generation	0	1	1	1	3	3	3	6	6	6
Cogenerators[4]										
Coal	47	52	53	52	52	52	52	52	52	52
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	240	240	256	259	258	298	304	304
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**347**	**348**	**369**	**372**	**372**	**421**	**428**	**427**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	150	171	171	171	176	176	176	200	201	201
Generation for Own Use	156	180	182	181	198	200	200	226	231	231
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1146	1317	1316	1316	1452	1448	1450	1699	1695	1696
Commercial	1083	1275	1273	1273	1432	1429	1430	1644	1640	1641
Industrial	1063	1144	1142	1143	1227	1223	1224	1411	1406	1407
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3309**	**3762**	**3757**	**3758**	**4146**	**4134**	**4139**	**4803**	**4790**	**4793**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	7.5	7.5	7.5	7.5	7.5	7.6	7.6	7.6
Commercial	7.3	6.7	6.7	6.7	6.0	6.1	6.1	6.2	6.2	6.2
Industrial	4.4	4.2	4.2	4.2	3.8	3.9	3.9	4.0	4.0	4.0
Transportation	5.3	4.9	4.9	4.9	4.6	4.7	4.6	4.4	4.5	4.5
All Sectors Average	**6.6**	**6.2**	**6.2**	**6.2**	**5.9**	**5.9**	**5.9**	**6.0**	**6.0**	**6.0**
Prices by Service Category [9]										
(1999 cents per kwh)										
Generation	4.1	3.6	3.6	3.6	3.2	3.2	3.2	3.4	3.4	3.4
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.82	10.39	10.39	10.39	9.70	9.70	9.70	8.95	8.95	8.95
Nitrogen Oxide	5.46	4.22	1.55	3.10	4.20	1.55	1.55	4.37	1.60	1.59

[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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	302.1	301.8	317.4	311.7	311.7	317.8	312.3	312.2
Other Fossil Steam[3]	138.2	129.6	125.4	125.4	121.1	118.3	117.9	117.2	115.1	114.7
Combined Cycle	20.2	49.4	56.5	56.2	124.0	129.6	128.6	230.0	234.9	235.3
Combustion Turbine/Diesel	75.6	129.7	128.4	128.5	162.1	159.1	160.7	207.7	209.6	209.2
Nuclear Power	97.4	97.5	97.5	97.5	94.2	94.2	94.2	71.6	71.6	71.6
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]	88.1	91.5	91.5	91.6	94.8	94.6	94.7	96.3	96.2	96.2
Distributed Generation[5]	0.0	2.0	2.2	2.2	6.1	6.3	6.2	14.0	13.8	13.2
Total	**745.0**	**821.5**	**823.1**	**822.6**	**939.4**	**933.3**	**933.6**	**1074.3**	**1073.2**	**1072.2**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	2.9	3.0	20.1	13.9	14.3	21.5	15.6	15.9
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	20.8	27.9	27.6	95.7	101.2	100.2	201.6	206.5	206.9
Combustion Turbine/Diesel	0.0	57.0	56.4	56.5	90.8	88.8	90.4	137.2	140.3	140.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.6	0.6	0.7	1.9	1.7	1.8	2.4	2.2	2.3
Distributed Generation[5]	0.0	2.0	2.2	2.2	6.1	6.3	6.2	14.0	13.8	13.2
Total	**0.0**	**82.9**	**90.0**	**90.0**	**214.6**	**211.9**	**213.0**	**376.7**	**378.4**	**378.4**
Cumulative Total Additions	**0.0**	**94.5**	**101.6**	**101.6**	**228.1**	**225.4**	**226.5**	**391.4**	**393.2**	**393.2**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	7.3	7.7	9.2	9.2	9.6	10.2	10.4	10.7
Other Fossil Steam	0.0	8.5	12.7	12.7	17.0	19.8	20.2	20.9	23.0	23.4
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Combustion Turbine/Diesel	0.0	3.8	4.0	4.0	5.1	5.8	5.7	5.9	6.7	6.8
Nuclear Power	0.0	0.0	0.0	0.0	3.3	3.3	3.3	25.9	25.9	25.9
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[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**19.0**	**24.2**	**24.5**	**34.9**	**38.5**	**39.2**	**63.4**	**66.4**	**67.2**
Cogenerators[8]										
Capability										
Coal Steam	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	40.1	40.1	42.9	43.2	43.2	48.8	49.7	49.7
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
Renewable Sources[4]	5.3	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	**51.6**	**59.2**	**59.3**	**59.3**	**63.1**	**63.4**	**63.4**	**70.7**	**71.6**	**71.6**
Cumulative Additions[6]	**0.0**	**7.5**	**7.7**	**7.7**	**11.4**	**11.8**	**11.7**	**19.0**	**20.0**	**19.9**

Table A5. Electricity Generating Capability (Continued)

(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 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 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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 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	147.8	202.8	201.7	191.2	183.2	192.8	187.6	206.7	211.7	213.0
Gross Domestic Trade	**330.0**	**328.1**	**327.0**	**316.5**	**286.1**	**295.7**	**290.5**	**206.7**	**211.7**	**213.0**
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)	4292.5	6044.9	5822.4	5626.3	4987.6	5229.0	5222.0	6227.5	6404.0	6456.3
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**11728.2**	**11532.1**	**9838.8**	**10080.3**	**10073.2**	**6227.5**	**6404.0**	**6456.3**
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.

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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Production										
Dry Gas Production[1]	18.67	20.72	20.61	20.68	23.03	23.21	23.21	28.84	28.90	28.96
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**	**4.47**	**4.50**	**4.51**	**4.94**	**5.03**	**5.03**	**5.83**	**5.90**	**5.90**
Canada	3.29	4.28	4.31	4.32	4.68	4.77	4.77	5.46	5.53	5.53
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	0.37	0.37	0.37	0.51	0.50	0.50	0.77	0.77	0.78
Total Supply	**22.15**	**25.30**	**25.23**	**25.30**	**28.03**	**28.29**	**28.30**	**34.72**	**34.85**	**34.92**
Consumption by Sector										
Residential	4.72	5.32	5.32	5.32	5.54	5.55	5.54	6.14	6.13	6.14
Commercial	3.07	3.62	3.62	3.62	3.78	3.78	3.77	4.02	4.01	4.02
Industrial[3]	7.95	8.80	8.84	8.81	9.33	9.34	9.33	10.17	10.18	10.19
Electric Generators[4]	3.72	5.26	5.17	5.24	6.72	6.96	6.99	11.19	11.31	11.36
Lease and Plant Fuel[5]	1.23	1.35	1.34	1.34	1.49	1.50	1.50	1.83	1.84	1.84
Pipeline Fuel	0.64	0.75	0.74	0.75	0.87	0.87	0.87	1.06	1.06	1.06
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.35**	**25.14**	**25.09**	**25.14**	**27.82**	**28.08**	**28.10**	**34.55**	**34.68**	**34.75**
Discrepancy[7]	**0.80**	**0.16**	**0.14**	**0.16**	**0.21**	**0.21**	**0.20**	**0.17**	**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.

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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A. 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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A8. 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 Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	2.47	2.49	2.68	2.68	2.72	3.14	3.18	3.15
Average Import Price	2.29	2.48	2.48	2.48	2.41	2.41	2.42	2.67	2.72	2.72
Average[2]	**2.11**	**2.49**	**2.47**	**2.48**	**2.63**	**2.63**	**2.66**	**3.05**	**3.09**	**3.07**
Delivered Prices										
Residential	6.69	6.81	6.79	6.80	6.70	6.70	6.74	6.74	6.78	6.75
Commercial	5.49	5.45	5.43	5.44	5.64	5.65	5.68	5.87	5.91	5.89
Industrial[3]	2.87	3.26	3.23	3.25	3.39	3.38	3.42	3.87	3.92	3.89
Electric Generators[4]	2.59	2.94	2.89	2.91	3.08	3.07	3.11	3.68	3.74	3.72
Transportation[5]	7.21	6.99	6.96	6.97	7.22	7.24	7.27	7.53	7.57	7.54
Average[6]	**4.16**	**4.36**	**4.34**	**4.35**	**4.38**	**4.37**	**4.40**	**4.64**	**4.68**	**4.66**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.31	4.31	4.07	4.08	4.08	3.69	3.69	3.68
Commercial	3.37	2.96	2.96	2.96	3.01	3.02	3.02	2.82	2.82	2.82
Industrial[3]	0.75	0.76	0.76	0.76	0.76	0.76	0.76	0.82	0.82	0.82
Electric Generators[4]	0.48	0.45	0.42	0.42	0.45	0.45	0.45	0.63	0.64	0.64
Transportation[5]	5.10	4.49	4.48	4.49	4.59	4.61	4.61	4.48	4.47	4.47
Average[6]	**2.05**	**1.87**	**1.86**	**1.86**	**1.75**	**1.74**	**1.74**	**1.59**	**1.59**	**1.59**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.95	22.95	22.55	22.62	22.59	22.62	22.60	22.59
Commercial	10.36	10.71	10.71	10.71	11.40	11.42	11.40	11.32	11.31	11.31
Industrial[3]	6.00	6.72	6.71	6.71	7.10	7.06	7.09	8.34	8.37	8.34
Electric Generators[4]	1.77	2.35	2.17	2.21	3.03	3.10	3.11	7.00	7.28	7.31
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.42	0.42	0.69	0.69	0.69
Total	**39.82**	**42.98**	**42.78**	**42.83**	**44.49**	**44.62**	**44.61**	**49.97**	**50.25**	**50.24**

[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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005	NO_x Cap 2008
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.42**	**20.42**	**20.81**	**20.81**	**20.80**	**21.46**	**21.45**	**21.46**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.60**	**5.60**	**5.15**	**5.14**	**5.14**	**5.01**	**5.03**	**5.03**
Lower 48 Onshore	3.27	2.75	2.75	2.75	2.49	2.48	2.48	2.63	2.65	2.64
Conventional	2.59	2.15	2.15	2.15	1.82	1.82	1.82	1.91	1.91	1.91
Enhanced Oil Recovery	0.68	0.61	0.61	0.61	0.66	0.66	0.66	0.72	0.74	0.73
Lower 48 Offshore	1.56	2.05	2.05	2.05	2.02	2.02	2.02	1.75	1.75	1.75
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.47**	**15.47**	**14.03**	**14.00**	**14.00**	**13.43**	**13.50**	**13.49**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**2.47**	**2.49**	**2.68**	**2.68**	**2.72**	**3.14**	**3.18**	**3.15**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**20.61**	**20.68**	**23.03**	**23.21**	**23.21**	**28.84**	**28.90**	**28.96**
Lower 48 Onshore	12.83	14.33	14.28	14.28	16.32	16.41	16.45	21.20	21.24	21.29
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.34	1.34	1.35	1.35	1.35
Non-Associated	11.03	12.82	12.77	12.77	14.98	15.07	15.11	19.85	19.89	19.94
Conventional	6.64	7.19	7.21	7.19	8.31	8.45	8.39	11.38	11.31	11.34
Unconventional	4.39	5.62	5.57	5.58	6.66	6.62	6.72	8.48	8.58	8.60
Lower 48 Offshore	5.43	5.93	5.86	5.93	6.21	6.30	6.26	7.07	7.08	7.10
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.07	1.07	1.01	1.01	1.01
Non-Associated	4.50	4.85	4.79	4.86	5.13	5.22	5.19	6.06	6.08	6.09
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**	**166.23**	**166.32**	**166.30**	**174.58**	**174.32**	**175.12**	**188.20**	**188.66**	**189.57**
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)	**17.94**	**24.11**	**23.94**	**24.06**	**28.67**	**28.82**	**29.15**	**39.25**	**39.89**	**39.44**

[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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008	Reference	NO$_x$ Cap 2005	NO$_x$ Cap 2008
Production[1]										
Appalachia	434	422	425	422	412	413	408	395	396	396
Interior	185	180	180	178	177	179	179	163	161	162
West	485	633	622	623	708	673	680	784	767	762
East of the Mississippi	561	554	557	553	545	549	544	525	524	524
West of the Mississippi	543	681	669	671	752	716	724	817	800	796
Total	**1105**	**1235**	**1226**	**1224**	**1297**	**1265**	**1268**	**1342**	**1324**	**1320**
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]	**1055**	**1191**	**1182**	**1180**	**1256**	**1225**	**1228**	**1306**	**1288**	**1284**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	83	83	84	85	85	86	87	87
Coke Plants	28	26	26	26	23	23	23	19	19	19
Electric Generators[4]	922	1078	1069	1066	1145	1115	1116	1198	1179	1174
Total	**1034**	**1192**	**1183**	**1180**	**1257**	**1228**	**1229**	**1308**	**1290**	**1285**
Discrepancy and Stock Change[5]	**21**	**-1**	**-1**	**-1**	**-1**	**-3**	**-1**	**-2**	**-2**	**-1**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	14.88	14.82	13.69	13.99	13.94	12.84	12.94	12.95
(1999 dollars per million Btu)	0.82	0.72	0.72	0.72	0.67	0.68	0.68	0.63	0.64	0.64
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	29.45	29.40	28.41	28.48	28.49	26.55	26.59	26.56
Coke Plants	44.20	42.47	42.45	42.39	41.29	41.33	41.42	38.57	38.52	38.65
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	22.68	22.62	20.84	21.20	21.18	19.40	19.67	19.62
(1999 dollars per million Btu)	1.22	1.13	1.13	1.13	1.05	1.06	1.06	0.98	0.99	0.99
Average	**25.82**	**23.53**	**23.59**	**23.53**	**21.72**	**22.08**	**22.06**	**20.15**	**20.41**	**20.37**
Exports[7]	37.43	36.32	36.32	36.25	35.54	35.58	35.66	33.13	33.11	33.18

[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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A11. Renewable Energy Generating Capability and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	NO_x Cap 2005	NO_x Cap 2008	Reference	NO_x Cap 2005 Case	NO_x Cap 2008 Case	Reference	NO_x Cap 2005 Case	NO_x Cap 2008 Case
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	78.62	78.62	78.74	78.74	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	3.16	3.21	3.24	4.31	4.17	4.22	4.34	4.23	4.26
Municipal Solid Waste[3]	2.59	3.15	3.11	3.16	3.56	3.51	3.55	4.07	4.02	4.07
Wood and Other Biomass[4]	1.52	1.68	1.68	1.68	2.04	2.04	2.04	2.37	2.37	2.37
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.43	4.43	5.51	5.51	5.51	5.78	5.78	5.78
Total	**88.07**	**91.47**	**91.48**	**91.56**	**94.76**	**94.57**	**94.67**	**96.33**	**96.16**	**96.24**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	299.05	299.05	298.99	298.99	298.99	297.94	297.94	297.94
Geothermal[2]	13.07	15.90	16.32	16.58	24.98	23.90	24.28	25.33	24.43	24.63
Municipal Solid Waste[3]	18.05	22.30	21.96	22.32	24.94	24.57	24.93	28.85	28.47	28.84
Wood and Other Biomass[4]	8.86	14.45	14.98	14.49	21.55	21.73	21.82	22.15	22.11	22.12
Dedicated Plants	7.56	8.67	8.67	8.67	10.88	10.88	10.88	13.35	13.35	13.35
Cofiring	1.30	5.78	6.31	5.82	10.67	10.85	10.94	8.80	8.76	8.77
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	4.46	9.42	9.42	9.42	12.33	12.33	12.33	13.10	13.10	13.10
Total	**352.79**	**362.28**	**362.89**	**363.03**	**384.41**	**383.13**	**383.97**	**390.09**	**388.78**	**389.36**
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**	**8.23**	**8.23**	**8.23**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.10**	**33.95**	**33.95**	**33.95**	**39.03**	**39.03**	**39.03**	**47.55**	**47.55**	**47.55**
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.

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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case	Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case	Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.44**	**0.44**	**0.44**
Wood	0.41	0.43	0.43	0.43	0.43	0.43	0.43	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**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Electric Generators[5]	**3.86**	**4.03**	**4.05**	**4.05**	**4.47**	**4.44**	**4.45**	**4.56**	**4.52**	**4.53**
Conventional Hydroelectric	3.17	3.08	3.08	3.08	3.08	3.08	3.08	3.06	3.06	3.06
Geothermal	0.27	0.37	0.38	0.39	0.66	0.62	0.64	0.67	0.64	0.65
Municipal Solid Waste[6]	0.25	0.30	0.30	0.30	0.34	0.33	0.34	0.39	0.39	0.39
Biomass	0.12	0.18	0.18	0.18	0.26	0.26	0.26	0.27	0.27	0.27
Dedicated Plants	0.10	0.11	0.10	0.11	0.13	0.13	0.13	0.16	0.16	0.16
Cofiring	0.02	0.07	0.08	0.07	0.13	0.13	0.13	0.11	0.11	0.11
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	0.10	0.10	0.10	0.13	0.13	0.13	0.13	0.13	0.13
Total Marketed Renewable Energy	**6.61**	**7.16**	**7.18**	**7.18**	**7.84**	**7.80**	**7.82**	**8.40**	**8.36**	**8.38**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.16	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**

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[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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A13. 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 Cap 2005 Case	NO_x Cap 2008 Case	Reference	NO_x Cap 2005 Case	NO_x Cap 2008 Case	Reference	NO_x Cap 2005 Case	NO_x Cap 2008 Case
Residential										
Petroleum	26.0	26.8	26.9	26.9	24.4	24.4	24.4	22.9	22.9	22.9
Natural Gas	69.5	78.6	78.7	78.7	82.0	82.0	81.9	90.8	90.7	90.7
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	192.6	223.2	221.3	221.0	240.4	237.1	237.4	274.7	272.3	271.9
Total	**289.3**	**330.0**	**328.1**	**327.8**	**348.1**	**344.9**	**345.0**	**389.6**	**387.1**	**386.8**
Commercial										
Petroleum	13.7	12.9	12.9	12.9	13.1	13.1	13.1	12.9	12.9	12.9
Natural Gas	45.4	53.5	53.5	53.5	56.0	55.9	55.8	59.4	59.3	59.4
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	214.1	213.8	237.0	234.0	234.1	265.8	263.5	263.0
Total	**242.9**	**284.1**	**282.3**	**282.0**	**307.9**	**304.9**	**304.8**	**340.0**	**337.6**	**337.2**
Industrial[1]										
Petroleum	104.2	99.0	98.9	98.9	104.7	104.6	104.7	115.6	115.7	115.5
Natural Gas[2]	141.6	147.8	147.9	147.9	157.6	157.9	157.6	174.9	175.1	175.2
Coal	55.9	66.5	66.6	66.6	66.3	66.3	66.4	66.4	66.5	66.5
Electricity	178.8	193.9	192.1	191.9	203.0	200.3	200.5	228.1	225.9	225.5
Total	**480.4**	**507.2**	**505.5**	**505.3**	**531.6**	**529.1**	**529.2**	**584.9**	**583.2**	**582.6**
Transportation										
Petroleum[3]	485.8	556.8	556.7	556.7	608.6	608.5	608.3	705.1	704.9	704.8
Natural Gas[4]	9.5	11.8	11.8	11.8	14.1	14.2	14.2	17.9	17.9	17.9
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	4.3	5.7	5.7	5.7	7.9	7.8	7.8
Total[3]	**498.2**	**573.1**	**573.0**	**573.0**	**628.6**	**628.4**	**628.3**	**730.9**	**730.7**	**730.6**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	695.4	695.4	750.8	750.6	750.5	856.4	856.4	856.0
Natural Gas	266.0	291.8	292.0	292.0	309.7	310.1	309.6	342.9	343.0	343.3
Coal	58.8	69.6	69.6	69.6	69.5	69.5	69.5	69.6	69.7	69.7
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	637.5	631.9	631.1	686.1	677.1	677.6	776.5	769.5	768.1
Total[3]	**1510.8**	**1694.3**	**1689.0**	**1688.1**	**1816.2**	**1807.3**	**1807.3**	**2045.4**	**2038.7**	**2037.2**
Electric Generators[6]										
Petroleum	20.0	6.8	6.1	6.2	3.5	3.6	3.7	3.9	3.8	3.8
Natural Gas	45.8	77.1	75.8	76.9	98.6	102.1	102.6	164.1	166.0	166.7
Coal	490.5	553.6	549.9	548.0	584.0	571.4	571.3	608.4	599.7	597.7
Total	**556.3**	**637.5**	**631.9**	**631.1**	**686.1**	**677.1**	**677.6**	**776.5**	**769.5**	**768.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	701.5	701.6	754.3	754.2	754.2	860.3	860.2	859.8
Natural Gas	311.8	368.9	367.8	368.9	408.2	412.1	412.2	507.1	508.9	509.9
Coal	549.3	623.1	619.5	617.6	653.5	640.9	640.8	678.0	669.4	667.4
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**	**1694.3**	**1689.0**	**1688.1**	**1816.2**	**1807.3**	**1807.3**	**2045.4**	**2038.7**	**2037.2**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.0**	**6.0**	**6.3**	**6.3**	**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.

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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Table A14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case	Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case	Reference	NO$_x$ Cap 2005 Case	NO$_x$ Cap 2008 Case
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	9.46	8.95	10.76	9.46	8.95	15.24	14.07	14.74
SO$_2$ Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**177.85**	**177.76**	**169.55**	**181.42**	**182.50**	**246.09**	**247.41**	**246.82**
NO$_x$ Controls (gigawatts)										
Combustion	0.00	65.84	116.86	116.20	66.93	118.01	117.66	67.57	118.06	117.70
SCR	0.00	84.31	244.32	84.00	85.97	246.67	231.61	89.75	251.97	242.85
SNCR	0.00	25.36	37.43	1.78	28.78	38.86	46.42	38.69	58.61	59.69
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	589.51	590.48	656.33	623.93	628.46	730.01	712.19	705.95
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	451.83	449.68	453.06	454.07	451.48	438.05	435.90	437.15
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	184.99	183.48	187.25	187.40	188.17	174.20	176.34	177.38

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[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO$_2$ = Sulfur 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 MCBASE.D121300A, MCNOX05.D121300A, and MCNOX08.D121300A.

Appendix B

Tables for 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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.85	11.85	10.90	10.89	10.89	10.61	10.67	10.66
Natural Gas Plant Liquids	2.62	3.02	2.97	2.97	3.31	3.35	3.32	4.07	4.07	4.08
Dry Natural Gas	19.16	21.26	20.92	20.88	23.63	23.90	23.64	29.59	29.62	29.69
Coal	23.12	25.43	25.52	25.63	26.47	25.82	26.43	27.21	27.07	27.27
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.05	5.96
Renewable Energy[1]	6.50	6.98	7.13	7.02	7.65	7.69	7.68	8.20	8.23	8.22
Other[2]	1.65	0.57	0.57	0.57	0.33	0.54	0.52	0.33	0.32	0.33
Total	**73.30**	**77.01**	**76.86**	**76.82**	**79.98**	**79.87**	**80.17**	**86.18**	**86.03**	**86.22**
Imports										
Crude Oil[3]	18.96	23.21	23.18	23.19	25.22	25.17	25.11	26.48	26.45	26.47
Petroleum Products[4]	4.14	4.85	4.85	4.88	6.46	6.30	6.41	10.77	10.72	10.71
Natural Gas	3.63	4.90	4.94	4.93	5.49	5.62	5.56	6.60	6.72	6.71
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**	**34.08**	**34.09**	**34.11**	**38.12**	**38.04**	**38.04**	**44.82**	**44.85**	**44.85**
Exports										
Petroleum[6]	1.98	1.81	1.80	1.81	1.79	1.78	1.78	1.90	1.91	1.91
Natural Gas	0.17	0.33	0.33	0.33	0.43	0.43	0.43	0.63	0.63	0.63
Coal	1.48	1.51	1.52	1.51	1.45	1.45	1.45	1.41	1.38	1.38
Total	**3.62**	**3.64**	**3.65**	**3.64**	**3.67**	**3.65**	**3.65**	**3.94**	**3.92**	**3.93**
Discrepancy[7]	**0.95**	**0.39**	**0.41**	**0.39**	**0.21**	**0.27**	**0.26**	**-0.03**	**-0.07**	**0.01**
Consumption										
Petroleum Products[8]	38.07	41.40	41.33	41.36	44.43	44.40	44.40	50.60	50.57	50.57
Natural Gas	21.90	25.78	25.48	25.43	28.52	28.91	28.60	35.40	35.54	35.60
Coal	21.46	24.37	24.44	24.57	25.54	24.91	25.55	26.48	26.38	26.52
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.05	5.96
Renewable Energy[1]	6.51	6.98	7.13	7.02	7.66	7.70	7.69	8.21	8.23	8.23
Other[9]	0.35	0.61	0.61	0.61	0.38	0.38	0.38	0.25	0.25	0.25
Total	**96.09**	**107.05**	**106.89**	**106.90**	**114.21**	**113.99**	**114.30**	**127.10**	**127.02**	**127.13**
Net Imports - Petroleum	**21.12**	**26.26**	**26.23**	**26.26**	**29.88**	**29.69**	**29.74**	**35.36**	**35.26**	**35.27**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	2.46	2.45	2.68	2.67	2.63	3.14	3.20	3.25
Coal Minemouth Price (dollars per ton)	17.23	14.76	12.97	13.62	13.69	12.41	12.71	12.84	11.94	11.87
Average Electric Price (cents per Kwh)	6.6	6.2	6.1	6.1	5.9	5.9	5.9	6.0	6.0	6.1

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, imports of unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.
Mcf = Thousand cubic feet.
Kwh = Kilowatthour.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.88	0.88	0.81	0.81	0.80	0.75	0.75	0.75
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	0.41	0.42	0.41	0.39	0.40	0.40
Petroleum Subtotal	1.42	1.42	1.42	1.42	1.29	1.30	1.29	1.21	1.22	1.22
Natural Gas	4.85	5.46	5.47	5.47	5.69	5.69	5.70	6.30	6.29	6.28
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	0.43	0.43	0.43	0.43	0.43	0.43	0.44	0.44	0.44
Electricity	3.91	4.50	4.50	4.50	4.96	4.93	4.95	5.80	5.79	5.77
Delivered Energy	**10.62**	**11.86**	**11.87**	**11.87**	**12.42**	**12.41**	**12.43**	**13.80**	**13.78**	**13.75**
Electricity Related Losses	8.46	9.46	9.41	9.41	9.88	9.79	9.91	10.58	10.58	10.61
Total	**19.08**	**21.32**	**21.27**	**21.28**	**22.30**	**22.20**	**22.33**	**24.38**	**24.36**	**24.35**
Commercial										
Distillate Fuel	0.36	0.41	0.41	0.41	0.41	0.41	0.41	0.39	0.39	0.39
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.66	0.66	0.67	0.67	0.67	0.66	0.66	0.66
Natural Gas	3.15	3.71	3.72	3.72	3.89	3.88	3.89	4.12	4.12	4.11
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.35	4.36	4.89	4.88	4.89	5.61	5.60	5.59
Delivered Energy	**7.59**	**8.87**	**8.88**	**8.89**	**9.60**	**9.58**	**9.60**	**10.55**	**10.53**	**10.51**
Electricity Related Losses	8.00	9.15	9.10	9.10	9.74	9.68	9.79	10.23	10.23	10.28
Total	**15.59**	**18.02**	**17.98**	**17.99**	**19.34**	**19.26**	**19.39**	**20.79**	**20.76**	**20.79**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.13	1.13	1.27	1.27	1.27	1.44	1.45	1.45
Liquefied Petroleum Gas	2.32	2.45	2.45	2.45	2.50	2.51	2.50	2.83	2.84	2.84
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	0.22	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.28	0.28
Motor Gasoline[2]	0.21	0.23	0.23	0.23	0.25	0.25	0.25	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.49	4.49	4.49	4.76	4.76	4.76	5.25	5.25	5.24
Petroleum Subtotal	9.39	9.95	9.94	9.94	10.55	10.55	10.55	11.78	11.79	11.79
Natural Gas[6]	9.43	10.42	10.41	10.41	11.11	11.12	11.11	12.33	12.32	12.34
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.82	1.82	1.85	1.85	1.85	1.89	1.90	1.90
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	2.62	2.62	2.62	2.61	2.61	2.61	2.62	2.62	2.62
Renewable Energy[7]	2.15	2.42	2.42	2.42	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.63	3.90	3.90	3.91	4.19	4.17	4.18	4.81	4.79	4.80
Delivered Energy	**27.15**	**29.32**	**29.29**	**29.29**	**31.10**	**31.11**	**31.09**	**34.62**	**34.61**	**34.63**
Electricity Related Losses	7.85	8.22	8.16	8.16	8.34	8.29	8.37	8.78	8.76	8.83
Total	**35.00**	**37.53**	**37.45**	**37.45**	**39.45**	**39.39**	**39.46**	**43.40**	**43.37**	**43.46**

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Transportation										
Distillate Fuel	5.13	6.28	6.28	6.28	6.99	6.99	6.99	8.21	8.20	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	17.70	17.70	17.70	19.05	19.04	19.04	21.32	21.32	21.32
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	0.04	0.06	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	29.06	29.06	31.75	31.75	31.75	36.77	36.76	36.77
Pipeline Fuel Natural Gas	0.66	0.77	0.76	0.76	0.89	0.90	0.89	1.08	1.09	1.09
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	0.00	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**	**29.99**	**29.99**	**29.99**	**32.89**	**32.89**	**32.88**	**38.23**	**38.22**	**38.23**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.23	0.24	0.30	0.30	0.31
Total	**26.41**	**30.18**	**30.18**	**30.17**	**33.12**	**33.13**	**33.12**	**38.53**	**38.53**	**38.53**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.71	8.70	9.47	9.47	9.47	10.80	10.79	10.80
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	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	3.03	3.02	3.02	3.05	3.06	3.05	3.38	3.40	3.39
Motor Gasoline[2]	16.17	17.96	17.96	17.96	19.32	19.32	19.31	21.63	21.63	21.63
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	1.05	1.17	1.17	1.17	1.21	1.21	1.21	1.25	1.25	1.25
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.04	5.04	5.58	5.58	5.57
Petroleum Subtotal	36.95	41.08	41.08	41.08	44.26	44.27	44.25	50.42	50.43	50.43
Natural Gas[6]	18.11	20.42	20.41	20.41	21.67	21.69	21.68	24.00	23.97	23.97
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.94	1.94	1.98	1.98	1.98	2.02	2.03	2.03
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	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.75	2.75
Renewable Energy[13]	2.65	2.95	2.95	2.95	3.19	3.19	3.19	3.65	3.65	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.85	12.86	14.15	14.10	14.13	16.39	16.34	16.31
Delivered Energy	**71.65**	**80.04**	**80.03**	**80.04**	**86.01**	**85.99**	**86.00**	**97.20**	**97.14**	**97.12**
Electricity Related Losses	24.44	27.02	26.85	26.86	28.20	28.00	28.30	29.89	29.88	30.01
Total	**96.09**	**107.05**	**106.89**	**106.90**	**114.21**	**113.99**	**114.30**	**127.10**	**127.02**	**127.13**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.03	0.04	0.04	0.02	0.03	0.04	0.03	0.03
Residual Fuel	1.07	0.27	0.21	0.23	0.13	0.11	0.12	0.14	0.11	0.11
Petroleum Subtotal	1.13	0.32	0.24	0.28	0.17	0.13	0.14	0.19	0.14	0.14
Natural Gas	3.79	5.36	5.07	5.02	6.84	7.22	6.91	11.40	11.57	11.63
Steam Coal	18.81	21.63	21.69	21.83	22.80	22.17	22.81	23.73	23.63	23.77
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.05	5.96
Renewable Energy[15]	3.86	4.03	4.18	4.07	4.47	4.51	4.50	4.56	4.58	4.58
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.37	0.37	0.24	0.24	0.24
Total	**35.73**	**39.85**	**39.70**	**39.71**	**42.35**	**42.10**	**42.43**	**46.28**	**46.22**	**46.33**

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.74	8.74	9.51	9.49	9.50	10.84	10.82	10.83
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	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	3.03	3.02	3.02	3.05	3.06	3.05	3.38	3.40	3.39
Motor Gasoline[2]	16.17	17.96	17.96	17.96	19.32	19.32	19.31	21.63	21.63	21.63
Petrochemical Feedstock	1.29	1.42	1.42	1.42	1.53	1.53	1.53	1.70	1.70	1.70
Residual Fuel	2.12	1.44	1.38	1.41	1.34	1.32	1.32	1.39	1.36	1.36
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.04	5.04	5.58	5.58	5.57
Petroleum Subtotal	38.07	41.40	41.33	41.36	44.43	44.40	44.40	50.60	50.57	50.57
Natural Gas	21.90	25.78	25.48	25.43	28.52	28.91	28.60	35.40	35.54	35.60
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.65	23.57	23.63	23.77	24.77	24.14	24.78	25.75	25.66	25.79
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	21.46	24.37	24.44	24.57	25.54	24.91	25.55	26.48	26.38	26.52
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.69	7.69	6.17	6.05	5.96
Renewable Energy[17]	6.51	6.98	7.13	7.02	7.66	7.70	7.69	8.21	8.24	8.23
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.37	0.37	0.24	0.24	0.24
Total	**96.09**	**107.05**	**106.89**	**106.90**	**114.21**	**113.99**	**114.30**	**127.10**	**127.02**	**127.13**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	80.03	80.04	86.01	85.99	86.00	97.20	97.14	97.12
Total Energy Use	96.09	107.05	106.89	106.90	114.21	113.99	114.30	127.10	127.02	127.13
Population (millions)	273.13	288.02	288.02	288.02	300.17	300.17	300.17	325.24	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10960	10960	10960	12667	12667	12667	16515	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1691.9	1694.9	1816.2	1806.4	1818.0	2045.4	2045.4	2050.0

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[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Residential	**13.12**	**12.91**	**12.87**	**12.83**	**13.15**	**13.25**	**13.14**	**13.59**	**13.67**	**13.81**
Primary Energy[1]	6.72	7.12	7.09	7.08	7.00	6.98	6.95	7.02	7.08	7.12
Petroleum Products[2]	7.55	9.18	9.17	9.17	9.37	9.16	9.20	9.66	9.65	9.66
Distillate Fuel	6.27	7.34	7.33	7.33	7.51	7.48	7.49	7.99	7.98	7.98
Liquefied Petroleum Gas	10.36	12.83	12.82	12.82	13.06	12.42	12.57	12.90	12.85	12.90
Natural Gas	6.52	6.63	6.60	6.59	6.52	6.53	6.49	6.56	6.63	6.67
Electricity	23.46	21.84	21.79	21.70	21.88	22.22	21.97	22.16	22.26	22.57
Commercial	**13.20**	**12.36**	**12.29**	**12.23**	**11.74**	**11.83**	**11.69**	**12.37**	**12.47**	**12.64**
Primary Energy[1]	5.22	5.35	5.32	5.32	5.53	5.51	5.49	5.76	5.81	5.85
Petroleum Products[2]	5.00	6.01	6.00	6.00	6.17	6.06	6.09	6.52	6.50	6.50
Distillate Fuel	4.37	5.13	5.12	5.12	5.28	5.25	5.26	5.77	5.75	5.75
Residual Fuel	2.63	3.64	3.63	3.64	3.69	3.69	3.69	3.85	3.85	3.85
Natural Gas[3]	5.34	5.31	5.28	5.27	5.49	5.50	5.46	5.72	5.78	5.83
Electricity	21.43	19.51	19.41	19.29	17.61	17.83	17.56	18.09	18.24	18.52
Industrial[4]	**5.32**	**5.49**	**5.45**	**5.44**	**5.44**	**5.36**	**5.34**	**5.85**	**5.88**	**5.95**
Primary Energy	3.92	4.25	4.23	4.22	4.37	4.25	4.26	4.73	4.75	4.77
Petroleum Products[2]	5.55	5.95	5.93	5.94	6.05	5.81	5.86	6.28	6.27	6.28
Distillate Fuel	4.65	5.29	5.28	5.28	5.46	5.43	5.44	5.98	5.95	5.94
Liquefied Petroleum Gas	8.50	7.94	7.93	7.93	8.00	7.33	7.48	7.86	7.82	7.87
Residual Fuel	2.78	3.37	3.36	3.36	3.42	3.42	3.42	3.58	3.58	3.58
Natural Gas[5]	2.79	3.17	3.14	3.13	3.30	3.29	3.25	3.77	3.84	3.88
Metallurgical Coal	1.65	1.58	1.58	1.58	1.54	1.53	1.54	1.44	1.43	1.43
Steam Coal	1.43	1.34	1.30	1.32	1.29	1.25	1.26	1.21	1.18	1.18
Electricity	13.01	12.30	12.21	12.11	11.21	11.36	11.16	11.60	11.73	12.00
Transportation	**8.30**	**9.27**	**9.25**	**9.25**	**9.45**	**9.43**	**9.47**	**9.32**	**9.31**	**9.31**
Primary Energy	8.29	9.25	9.24	9.24	9.44	9.41	9.45	9.30	9.29	9.29
Petroleum Products[2]	8.28	9.25	9.24	9.24	9.44	9.41	9.45	9.30	9.29	9.29
Distillate Fuel[6]	8.22	8.89	8.87	8.87	8.94	8.94	8.94	9.02	8.99	8.98
Jet Fuel[7]	4.70	5.24	5.23	5.23	5.46	5.46	5.47	5.88	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.63	10.63	10.92	10.88	10.94	10.68	10.68	10.68
Residual Fuel	2.46	3.10	3.10	3.10	3.18	3.17	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.17	14.17	14.24	13.70	13.83	13.88	13.84	13.88
Natural Gas[10]	7.02	6.80	6.76	6.75	7.03	7.04	7.01	7.33	7.39	7.44
Ethanol (E85)[11]	14.42	19.12	19.06	19.06	19.00	18.97	18.99	19.36	19.37	19.37
Methanol (M85)[12]	10.38	13.11	13.11	13.11	13.74	13.72	13.74	14.43	14.43	14.43
Electricity	15.58	14.29	14.19	14.12	13.53	13.79	13.66	13.03	13.16	13.33
Average End-Use Energy	**8.53**	**8.90**	**8.87**	**8.86**	**8.94**	**8.93**	**8.90**	**9.17**	**9.20**	**9.26**
Primary Energy	6.33	7.00	6.98	6.98	7.18	7.12	7.13	7.31	7.33	7.34
Electricity	19.40	18.10	18.02	17.92	17.18	17.42	17.18	17.57	17.70	17.98
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	1.41	1.41	1.52	1.50	1.47	1.85	1.84	1.86
Petroleum Products	2.50	3.70	3.69	3.68	4.06	4.14	4.11	4.33	4.40	4.41
Distillate Fuel	4.04	4.65	4.69	4.64	4.85	4.89	4.88	5.30	5.30	5.29
Residual Fuel	2.41	3.52	3.54	3.51	3.85	3.97	3.94	4.04	4.19	4.19
Natural Gas	2.54	2.89	2.85	2.83	3.02	3.02	2.98	3.61	3.68	3.72
Steam Coal	1.22	1.13	1.05	1.05	1.05	0.99	1.00	0.98	0.93	0.93

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.43	8.43	8.63	8.55	8.59	8.62	8.61	8.62
Distillate Fuel	7.27	8.07	8.06	8.05	8.18	8.18	8.18	8.41	8.38	8.38
Jet Fuel	4.70	5.24	5.23	5.23	5.46	5.46	5.47	5.88	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.83	8.82	8.87	8.22	8.36	8.64	8.61	8.66
Motor Gasoline[8]	9.45	10.64	10.63	10.63	10.92	10.88	10.94	10.68	10.68	10.68
Residual Fuel	2.48	3.26	3.25	3.25	3.33	3.33	3.33	3.49	3.49	3.49
Natural Gas	4.05	4.25	4.23	4.23	4.27	4.25	4.23	4.52	4.58	4.62
Coal	1.24	1.15	1.07	1.08	1.07	1.01	1.02	1.00	0.95	0.95
Ethanol (E85)[11]	14.42	19.12	19.06	19.06	19.00	18.97	18.99	19.36	19.37	19.37
Methanol (M85)[12]	10.38	13.11	13.11	13.11	13.74	13.72	13.74	14.43	14.43	14.43
Electricity	19.40	18.10	18.02	17.92	17.18	17.42	17.18	17.57	17.70	17.98
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	147.20	146.85	157.75	158.74	157.68	181.60	182.29	183.81
Commercial	99.10	108.63	108.17	107.72	111.63	112.42	111.24	129.48	130.24	131.76
Industrial	110.62	121.27	120.46	120.08	126.35	124.81	124.11	151.05	151.86	153.86
Transportation	212.64	270.40	270.13	270.10	301.90	300.96	302.24	345.30	345.00	345.03
Total Non-Renewable Expenditures	556.41	647.83	645.97	644.75	697.64	696.93	695.27	807.43	809.39	814.46
Transportation Renewable Expenditures	0.14	0.42	0.42	0.42	0.61	0.61	0.62	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**646.38**	**645.17**	**698.25**	**697.55**	**695.89**	**808.29**	**810.25**	**815.32**

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[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	2101	2124	2232	2146	2207	2317	2277	2287
Petroleum	104	32	24	28	18	14	15	19	15	15
Natural Gas[2]	365	574	579	564	867	939	891	1568	1605	1595
Nuclear Power	730	740	740	740	720	720	720	577	567	558
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	372	362	384	388	386	390	392	391
Total	**3386**	**3811**	**3815**	**3818**	**4220**	**4206**	**4218**	**4872**	**4855**	**4846**
Non-Utility Generation for Own Use	16	16	16	16	16	16	16	16	16	16
Distributed Generation	0	1	1	1	3	3	2	6	6	6
Cogenerators[4]										
Coal	47	52	52	53	52	52	52	52	52	52
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	238	237	256	256	255	298	307	306
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**345**	**345**	**369**	**370**	**368**	**421**	**430**	**429**
Other End-Use Generators	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	150	171	170	170	176	176	175	200	201	202
Generation for Own Use	156	180	180	180	198	199	198	226	234	231
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**35**	**35**	**23**	**23**	**23**
Electricity Sales by Sector										
Residential	1146	1317	1319	1320	1452	1446	1450	1699	1696	1690
Commercial	1083	1275	1276	1277	1432	1429	1432	1644	1640	1637
Industrial	1063	1144	1144	1145	1227	1223	1225	1411	1404	1406
Transportation	17	26	26	26	35	35	35	49	49	49
Total	**3309**	**3762**	**3765**	**3768**	**4146**	**4133**	**4142**	**4803**	**4788**	**4781**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	7.4	7.4	7.5	7.6	7.5	7.6	7.6	7.7
Commercial	7.3	6.7	6.6	6.6	6.0	6.1	6.0	6.2	6.2	6.3
Industrial	4.4	4.2	4.2	4.1	3.8	3.9	3.8	4.0	4.0	4.1
Transportation	5.3	4.9	4.8	4.8	4.6	4.7	4.7	4.4	4.5	4.5
All Sectors Average	**6.6**	**6.2**	**6.1**	**6.1**	**5.9**	**5.9**	**5.9**	**6.0**	**6.0**	**6.1**
Prices by Service Category[9] (1999 cents/kwh)										
Generation	4.1	3.6	3.6	3.5	3.2	3.2	3.2	3.4	3.4	3.5
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)										
Sulfur Dioxide	13.82	10.39	5.27	8.79	9.70	3.67	4.12	8.95	3.27	3.27
Nitrogen Oxide	5.46	4.22	4.13	4.15	4.20	4.04	4.16	4.37	4.25	4.28

[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	307.6	307.3	317.4	315.8	316.8	317.8	317.6	317.2
Other Fossil Steam[3]	138.2	129.6	126.1	125.9	121.1	116.8	117.1	117.2	111.1	114.4
Combined Cycle	20.2	49.4	63.7	61.2	124.0	136.5	133.0	230.0	234.0	226.8
Combustion Turbine/Diesel	75.6	129.7	119.9	121.7	162.1	149.5	157.8	207.7	210.7	212.7
Nuclear Power	97.4	97.5	97.5	97.5	94.2	93.7	94.2	71.6	70.5	68.9
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]	88.1	91.5	91.7	91.6	94.8	94.8	94.7	96.3	96.3	96.3
Distributed Generation[5]	0.0	2.0	1.8	1.8	6.1	6.1	5.6	14.0	14.7	13.1
Total	**745.0**	**821.5**	**827.9**	**826.4**	**939.4**	**932.9**	**938.8**	**1074.3**	**1074.7**	**1069.2**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	9.0	8.6	20.1	19.7	19.2	21.5	22.4	21.7
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	20.8	35.1	32.6	95.7	108.2	104.6	201.6	205.6	198.4
Combustion Turbine/Diesel	0.0	57.0	48.6	50.6	90.8	79.5	87.9	137.2	141.0	143.7
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	0.6	0.9	0.7	1.9	1.9	1.8	2.4	2.4	2.4
Distributed Generation[5]	0.0	2.0	1.8	1.8	6.1	6.1	5.6	14.0	14.7	13.1
Total	**0.0**	**82.9**	**95.4**	**94.3**	**214.6**	**215.4**	**219.1**	**376.7**	**386.1**	**379.2**
Cumulative Total Additions	**0.0**	**94.5**	**107.0**	**105.9**	**228.1**	**228.9**	**232.7**	**391.4**	**400.9**	**394.0**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	9.0	7.9	9.2	10.4	8.9	10.2	11.3	10.9
Other Fossil Steam[3]	0.0	8.5	11.9	12.2	17.0	21.3	21.0	20.9	27.0	23.7
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Combustion Turbine/Diesel	0.0	3.8	4.7	4.7	5.1	5.9	5.9	5.9	6.2	6.8
Nuclear Power	0.0	0.0	0.0	0.0	3.3	3.7	3.3	25.9	27.0	28.6
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[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	0.0	19.0	25.8	24.9	34.9	41.7	39.4	63.4	71.9	70.3
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	39.9	39.9	42.9	43.0	42.8	48.8	50.2	49.8
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
Renewable Sources[4]	5.3	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	**51.6**	**59.2**	**59.1**	**59.1**	**63.1**	**63.2**	**63.0**	**70.7**	**72.1**	**71.6**
Cumulative Additions[6]	**0.0**	**7.5**	**7.5**	**7.4**	**11.4**	**11.6**	**11.4**	**19.0**	**20.4**	**20.0**

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

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 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.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 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	147.8	202.8	200.2	203.4	183.2	177.6	182.0	206.7	207.6	201.1
Gross Domestic Trade	**330.0**	**328.1**	**325.4**	**328.6**	**286.1**	**280.5**	**284.9**	**206.7**	**207.6**	**201.1**
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)	4292.5	6044.9	5669.3	5661.5	4987.6	4884.3	4808.8	6227.5	6413.8	6319.6
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**11575.1**	**11567.3**	**9838.8**	**9735.6**	**9660.0**	**6227.5**	**6413.8**	**6319.6**
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.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B7. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Production										
Dry Gas Production[1]	18.67	20.72	20.39	20.35	23.03	23.29	23.04	28.84	28.87	28.94
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**	**4.47**	**4.51**	**4.50**	**4.94**	**5.07**	**5.01**	**5.83**	**5.94**	**5.93**
Canada	3.29	4.28	4.32	4.31	4.68	4.81	4.76	5.46	5.57	5.56
Mexico	-0.01	-0.18	-0.18	-0.18	-0.25	-0.25	-0.25	-0.40	-0.40	-0.40
Liquefied Natural Gas	0.10	0.37	0.37	0.37	0.51	0.51	0.50	0.77	0.78	0.78
Total Supply	**22.15**	**25.30**	**25.01**	**24.96**	**28.03**	**28.42**	**28.11**	**34.72**	**34.87**	**34.92**
Consumption by Sector										
Residential	4.72	5.32	5.32	5.33	5.54	5.54	5.55	6.14	6.12	6.11
Commercial	3.07	3.62	3.62	3.62	3.78	3.78	3.79	4.02	4.01	4.00
Industrial[3]	7.95	8.80	8.80	8.81	9.33	9.33	9.33	10.17	10.17	10.18
Electric Generators[4]	3.72	5.26	4.98	4.93	6.72	7.08	6.78	11.19	11.35	11.41
Lease and Plant Fuel[5]	1.23	1.35	1.33	1.33	1.49	1.50	1.49	1.83	1.83	1.84
Pipeline Fuel	0.64	0.75	0.74	0.74	0.87	0.88	0.87	1.06	1.06	1.06
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.35**	**25.14**	**24.85**	**24.80**	**27.82**	**28.21**	**27.90**	**34.55**	**34.69**	**34.76**
Discrepancy[7]	**0.80**	**0.16**	**0.16**	**0.16**	**0.21**	**0.21**	**0.21**	**0.17**	**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.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A. 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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	2.46	2.45	2.68	2.67	2.63	3.14	3.20	3.25
Average Import Price	2.29	2.48	2.48	2.48	2.41	2.41	2.41	2.67	2.75	2.75
Average[2]	**2.11**	**2.49**	**2.46**	**2.46**	**2.63**	**2.62**	**2.59**	**3.05**	**3.12**	**3.16**
Delivered Prices										
Residential	6.69	6.81	6.77	6.77	6.70	6.70	6.67	6.74	6.81	6.85
Commercial	5.49	5.45	5.42	5.41	5.64	5.64	5.61	5.87	5.94	5.99
Industrial[3]	2.87	3.26	3.22	3.21	3.39	3.38	3.34	3.87	3.94	3.99
Electric Generators[4]	2.59	2.94	2.90	2.89	3.08	3.08	3.04	3.68	3.75	3.79
Transportation[5]	7.21	6.99	6.94	6.93	7.22	7.23	7.20	7.53	7.59	7.64
Average[6]	**4.16**	**4.36**	**4.34**	**4.34**	**4.38**	**4.36**	**4.34**	**4.64**	**4.70**	**4.74**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.31	4.31	4.07	4.08	4.08	3.69	3.69	3.69
Commercial	3.37	2.96	2.95	2.95	3.01	3.02	3.02	2.82	2.82	2.83
Industrial[3]	0.75	0.76	0.76	0.76	0.76	0.76	0.75	0.82	0.82	0.83
Electric Generators[4]	0.48	0.45	0.44	0.43	0.45	0.46	0.45	0.63	0.63	0.63
Transportation[5]	5.10	4.49	4.48	4.48	4.59	4.61	4.61	4.48	4.47	4.48
Average[6]	**2.05**	**1.87**	**1.88**	**1.88**	**1.75**	**1.74**	**1.75**	**1.59**	**1.59**	**1.58**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.95	22.96	22.55	22.62	22.63	22.62	22.60	22.58
Commercial	10.36	10.71	10.70	10.71	11.40	11.42	11.43	11.32	11.32	11.30
Industrial[3]	6.00	6.72	6.66	6.66	7.10	7.05	7.01	8.34	8.36	8.43
Electric Generators[4]	1.77	2.35	2.18	2.12	3.03	3.24	3.04	7.00	7.16	7.20
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.42	0.42	0.69	0.69	0.69
Total	**39.82**	**42.98**	**42.73**	**42.69**	**44.49**	**44.75**	**44.53**	**49.97**	**50.13**	**50.21**

[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per barrel)	**16.49**	**20.42**	**20.41**	**20.41**	**20.81**	**20.84**	**20.81**	**21.46**	**21.44**	**21.46**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.60**	**5.60**	**5.15**	**5.14**	**5.14**	**5.01**	**5.04**	**5.04**
Lower 48 Onshore	3.27	2.75	2.75	2.75	2.49	2.48	2.48	2.63	2.65	2.66
Conventional	2.59	2.15	2.15	2.15	1.82	1.82	1.82	1.91	1.91	1.91
Enhanced Oil Recovery	0.68	0.61	0.61	0.61	0.66	0.66	0.66	0.72	0.74	0.74
Lower 48 Offshore	1.56	2.05	2.05	2.05	2.02	2.02	2.02	1.75	1.75	1.74
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.46**	**15.46**	**14.03**	**14.00**	**14.00**	**13.43**	**13.53**	**13.53**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**2.46**	**2.45**	**2.68**	**2.67**	**2.63**	**3.14**	**3.20**	**3.25**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**20.39**	**20.35**	**23.03**	**23.29**	**23.04**	**28.84**	**28.87**	**28.94**
Lower 48 Onshore	12.83	14.33	14.10	14.09	16.32	16.46	16.25	21.20	21.24	21.32
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.34	1.34	1.35	1.35	1.35
Non-Associated	11.03	12.82	12.60	12.58	14.98	15.13	14.91	19.85	19.89	19.96
Conventional	6.64	7.19	7.11	7.10	8.31	8.56	8.43	11.38	11.27	11.34
Unconventional	4.39	5.62	5.49	5.48	6.66	6.56	6.49	8.48	8.61	8.63
Lower 48 Offshore	5.43	5.93	5.81	5.80	6.21	6.32	6.29	7.07	7.06	7.05
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.07	1.07	1.01	1.01	1.01
Non-Associated	4.50	4.85	4.74	4.73	5.13	5.25	5.22	6.06	6.05	6.04
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**	**166.23**	**166.49**	**166.54**	**174.58**	**173.17**	**172.87**	**188.20**	**188.97**	**188.05**
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)	**17.94**	**24.11**	**23.97**	**23.74**	**28.67**	**28.69**	**27.86**	**39.25**	**40.11**	**40.39**

[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Production[1]										
Appalachia	434	422	383	408	412	379	400	395	388	389
Interior	185	180	145	163	177	154	156	163	145	141
West	485	633	739	691	708	751	753	784	813	829
East of the Mississippi	561	554	484	519	545	491	515	525	504	500
West of the Mississippi	543	681	784	743	752	793	795	817	843	859
Total	**1105**	**1235**	**1268**	**1262**	**1297**	**1283**	**1310**	**1342**	**1346**	**1359**
Net Imports										
Imports	9	16	16	16	17	17	17	20	20	20
Exports	58	60	60	60	58	57	57	56	55	55
Total	**-49**	**-44**	**-45**	**-44**	**-40**	**-40**	**-40**	**-36**	**-36**	**-36**
Total Supply[2]	**1055**	**1191**	**1223**	**1218**	**1256**	**1243**	**1270**	**1306**	**1311**	**1323**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	83	83	84	84	84	86	87	87
Coke Plants	28	26	26	26	23	23	23	19	19	19
Electric Generators[4]	922	1078	1109	1105	1145	1133	1160	1198	1204	1213
Total	**1034**	**1192**	**1223**	**1219**	**1257**	**1245**	**1273**	**1308**	**1315**	**1324**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**-0**	**-1**	**-1**	**-2**	**-3**	**-2**	**-4**	**-1**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	12.97	13.62	13.69	12.41	12.71	12.84	11.94	11.87
(1999 dollars per million Btu)	0.82	0.72	0.64	0.67	0.67	0.62	0.63	0.63	0.59	0.59
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	28.50	29.04	28.41	27.34	27.62	26.55	25.95	25.95
Coke Plants	44.20	42.47	42.46	42.33	41.29	41.11	41.19	38.57	38.40	38.43
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	20.53	20.79	20.84	19.30	19.56	19.40	18.30	18.30
(1999 dollars per million Btu)	1.22	1.13	1.05	1.05	1.05	0.99	1.00	0.98	0.93	0.93
Average	**25.82**	**23.53**	**21.53**	**21.81**	**21.72**	**20.25**	**20.48**	**20.15**	**19.09**	**19.09**
Exports[7]	37.43	36.32	35.75	36.07	35.54	34.82	34.94	33.13	32.44	32.47

[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

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

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	78.62	78.62	78.74	78.74	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	3.16	3.42	3.41	4.31	4.32	4.36	4.34	4.36	4.42
Municipal Solid Waste[3]	2.59	3.15	3.15	3.01	3.56	3.55	3.41	4.07	4.07	3.98
Wood and Other Biomass[4]	1.52	1.68	1.68	1.68	2.04	2.04	2.04	2.37	2.37	2.37
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.43	4.43	5.51	5.51	5.51	5.78	5.78	5.77
Total	**88.07**	**91.47**	**91.74**	**91.58**	**94.76**	**94.77**	**94.67**	**96.33**	**96.33**	**96.30**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	299.05	299.05	298.99	298.99	298.99	297.94	297.94	297.94
Geothermal[2]	13.07	15.90	17.99	17.88	24.98	25.09	25.41	25.33	25.42	25.93
Municipal Solid Waste[3]	18.05	22.30	22.29	21.15	24.94	24.92	23.80	28.85	28.83	28.15
Wood and Other Biomass[4]	8.86	14.45	22.25	13.62	21.55	24.89	23.85	22.15	24.28	23.37
Dedicated Plants	7.56	8.67	8.67	8.67	10.88	10.88	10.88	13.35	13.35	13.36
Cofiring	1.30	5.78	13.59	4.96	10.67	14.01	12.97	8.80	10.93	10.02
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	4.46	9.42	9.42	9.42	12.33	12.33	12.33	13.10	13.10	13.05
Total	**352.79**	**362.28**	**372.16**	**362.29**	**384.41**	**387.83**	**386.00**	**390.09**	**392.30**	**391.17**
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**	**8.23**	**8.23**	**8.23**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.92	29.92	35.01	35.01	35.01	43.52	43.52	43.52
Total	**31.10**	**33.95**	**33.95**	**33.95**	**39.03**	**39.03**	**39.03**	**47.55**	**47.55**	**47.55**
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.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.43**	**0.44**	**0.44**	**0.44**
Wood	0.41	0.43	0.43	0.43	0.43	0.43	0.43	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**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Electric Generators[5]	**3.86**	**4.03**	**4.18**	**4.07**	**4.47**	**4.51**	**4.50**	**4.56**	**4.58**	**4.58**
Conventional Hydroelectric	3.17	3.08	3.08	3.08	3.08	3.08	3.08	3.06	3.06	3.06
Geothermal	0.27	0.37	0.43	0.43	0.66	0.66	0.67	0.67	0.67	0.69
Municipal Solid Waste[6]	0.25	0.30	0.30	0.29	0.34	0.34	0.32	0.39	0.39	0.38
Biomass	0.12	0.18	0.26	0.17	0.26	0.29	0.28	0.27	0.30	0.29
Dedicated Plants	0.10	0.11	0.10	0.11	0.13	0.13	0.13	0.16	0.16	0.16
Cofiring	0.02	0.07	0.16	0.06	0.13	0.16	0.15	0.11	0.13	0.12
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	0.10	0.10	0.10	0.13	0.13	0.13	0.13	0.13	0.13
Total Marketed Renewable Energy	**6.61**	**7.16**	**7.31**	**7.20**	**7.84**	**7.88**	**7.87**	**8.40**	**8.42**	**8.42**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.16	0.16
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.23**	**0.24**

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[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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A

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	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Residential										
Petroleum	26.0	26.8	26.9	26.8	24.4	24.5	24.4	22.9	23.0	22.9
Natural Gas	69.5	78.6	78.7	78.8	82.0	82.0	82.1	90.8	90.5	90.4
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	192.6	223.2	222.5	223.6	240.4	236.5	240.9	274.7	274.9	276.0
Total	**289.3**	**330.0**	**329.4**	**330.5**	**348.1**	**344.3**	**348.7**	**389.6**	**389.7**	**390.6**
Commercial										
Petroleum	13.7	12.9	12.9	12.9	13.1	13.1	13.1	12.9	12.9	12.9
Natural Gas	45.4	53.5	53.6	53.6	56.0	55.9	56.0	59.4	59.3	59.1
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	215.3	216.3	237.0	233.7	237.9	265.8	265.9	267.4
Total	**242.9**	**284.1**	**283.5**	**284.6**	**307.9**	**304.6**	**308.9**	**340.0**	**340.0**	**341.4**
Industrial[1]										
Petroleum	104.2	99.0	98.8	98.8	104.7	104.7	104.5	115.6	115.9	115.8
Natural Gas[2]	141.6	147.8	147.6	147.6	157.6	157.8	157.6	174.9	174.8	175.0
Coal	55.9	66.5	66.5	66.6	66.3	66.3	66.3	66.4	66.5	66.6
Electricity	178.8	193.9	193.0	193.9	203.0	200.1	203.5	228.1	227.7	229.7
Total	**480.4**	**507.2**	**506.0**	**506.8**	**531.6**	**528.9**	**531.9**	**584.9**	**584.9**	**587.1**
Transportation										
Petroleum[3]	485.8	556.8	556.9	556.9	608.6	608.6	608.6	705.1	705.0	705.0
Natural Gas[4]	9.5	11.8	11.7	11.7	14.1	14.3	14.1	17.9	17.9	17.9
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	5.7	5.7	5.7	7.9	7.9	7.9
Total[3]	**498.2**	**573.1**	**573.1**	**573.0**	**628.6**	**628.6**	**628.5**	**730.9**	**730.9**	**730.9**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	695.5	695.4	750.8	750.9	750.6	856.4	856.6	856.6
Natural Gas	266.0	291.8	291.6	291.6	309.7	310.0	309.9	342.9	342.5	342.5
Coal	58.8	69.6	69.6	69.6	69.5	69.5	69.5	69.6	69.8	69.8
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	637.5	635.2	638.2	686.1	675.9	688.0	776.5	776.4	781.0
Total[3]	**1510.**	**1694.3**	**1691.9**	**1694.9**	**1816.2**	**1806.4**	**1818.0**	**2045.4**	**2045.4**	**2050.0**
Electric Generators[6]										
Petroleum	20.0	6.8	5.1	5.8	3.5	2.8	3.0	3.9	2.9	3.0
Natural Gas	45.8	77.1	73.0	72.3	98.6	103.9	99.6	164.1	166.6	167.5
Coal	490.5	553.6	557.1	560.1	584.0	569.2	585.4	608.4	606.9	610.6
Total	**556.3**	**637.5**	**635.2**	**638.2**	**686.1**	**675.9**	**688.0**	**776.5**	**776.4**	**781.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	700.6	701.2	754.3	753.7	753.6	860.3	859.6	859.5
Natural Gas	311.8	368.9	364.7	363.9	408.2	414.0	409.5	507.1	509.1	510.0
Coal	549.3	623.1	626.6	629.7	653.5	638.7	654.9	678.0	676.7	680.3
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.**	**1694.3**	**1691.9**	**1694.9**	**1816.2**	**1806.4**	**1818.0**	**2045.4**	**2045.4**	**2050.0**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**5.9**	**6.1**	**6.0**	**6.1**	**6.3**	**6.3**	**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.

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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Table B14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008	Reference	SO_2 Cap 2005	SO_2 Cap 2008
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	64.30	30.62	10.76	98.37	95.25	15.24	127.53	129.99
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**303.38**	**106.69**	**169.55**	**735.49**	**283.12**	**246.09**	**1083.65**	**1124.54**
NO_x Controls (gigawatts)										
Combustion	0.00	65.84	65.18	66.07	66.93	66.73	67.23	67.57	67.11	67.45
SCR	0.00	84.31	89.88	92.09	85.97	97.21	97.02	89.75	116.67	124.29
SNCR	0.00	25.36	19.69	14.65	28.78	23.45	18.06	38.69	32.32	27.34
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	701.98	650.36	656.33	691.47	693.56	730.01	751.46	767.60
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	388.13	438.72	453.06	385.95	401.41	438.05	409.08	408.53
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	177.39	173.09	187.25	205.93	214.85	174.20	185.68	182.71

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 MCBASE.D121300A, MCSO205.D121300A, and MCSO208.D121300A.

Appendix C

Tables for CO_2 Cap Cases

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.78	11.76	10.90	10.93	10.82	10.61	11.46	11.34
Natural Gas Plant Liquids	2.62	3.02	3.41	3.16	3.31	3.62	3.73	4.07	4.35	4.35
Dry Natural Gas	19.16	21.26	24.06	22.28	23.63	25.91	26.65	29.59	31.60	31.62
Coal	23.12	25.43	17.02	20.61	26.47	14.44	13.86	27.21	12.16	12.07
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.37	7.32
Renewable Energy[1]	6.50	6.98	8.26	8.31	7.65	10.75	11.09	8.20	12.71	12.49
Other[2]	1.65	0.57	0.35	0.36	0.33	0.30	0.30	0.33	0.34	0.33
Total	**73.30**	**77.01**	**72.78**	**74.39**	**79.98**	**73.87**	**74.36**	**86.18**	**79.99**	**79.53**
Imports										
Crude Oil[3]	18.96	23.21	22.66	22.99	25.22	24.93	24.98	26.48	25.66	25.74
Petroleum Products[4]	4.14	4.85	4.85	4.79	6.46	6.58	6.44	10.77	10.88	11.04
Natural Gas	3.63	4.90	5.71	5.50	5.49	6.63	6.70	6.60	8.07	7.98
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.89	0.88	0.96	0.82	0.82
Total	**27.37**	**34.08**	**34.25**	**34.30**	**38.12**	**39.03**	**38.99**	**44.82**	**45.43**	**45.58**
Exports										
Petroleum[6]	1.98	1.81	1.77	1.79	1.79	1.78	1.77	1.90	1.93	1.92
Natural Gas	0.17	0.33	0.12	0.12	0.43	0.12	0.12	0.63	0.12	0.12
Coal	1.48	1.51	1.51	1.51	1.45	1.43	1.42	1.41	1.44	1.44
Total	**3.62**	**3.64**	**3.40**	**3.43**	**3.67**	**3.33**	**3.32**	**3.94**	**3.48**	**3.48**
Discrepancy[7]	**0.95**	**0.39**	**0.22**	**0.24**	**0.21**	**0.20**	**0.21**	**-0.03**	**0.03**	**0.07**
Consumption										
Petroleum Products[8]	38.07	41.40	41.11	41.09	44.43	44.59	44.52	50.60	50.95	51.01
Natural Gas	21.90	25.78	29.58	27.61	28.52	32.21	33.03	35.40	39.36	39.29
Coal	21.46	24.37	15.94	19.50	25.54	13.38	12.76	26.48	11.14	11.05
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.37	7.32
Renewable Energy[1]	6.51	6.98	8.26	8.31	7.66	10.76	11.10	8.21	12.72	12.50
Other[9]	0.35	0.61	0.62	0.61	0.38	0.52	0.51	0.25	0.38	0.38
Total	**96.09**	**107.05**	**103.41**	**105.02**	**114.21**	**109.37**	**109.82**	**127.10**	**121.91**	**121.56**
Net Imports - Petroleum	**21.12**	**26.26**	**25.74**	**25.99**	**29.88**	**29.73**	**29.64**	**35.36**	**34.62**	**34.85**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	3.45	2.97	2.68	4.36	4.13	3.14	4.22	4.38
Coal Minemouth Price (dollars per ton)	17.23	14.76	14.78	14.82	13.69	13.77	13.72	12.84	12.55	12.54
Average Electric Price (cents per Kwh)	6.6	6.2	8.2	7.3	5.9	8.3	8.2	6.0	7.9	7.9

[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.89	0.89	0.81	0.81	0.81	0.75	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	0.46	0.46	0.41	0.42	0.42	0.39	0.41	0.41
Petroleum Subtotal	1.42	1.42	1.43	1.42	1.29	1.31	1.31	1.21	1.25	1.24
Natural Gas	4.85	5.46	5.30	5.38	5.69	5.37	5.44	6.30	6.04	6.02
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.43	0.43	0.43	0.43	0.42	0.42	0.44	0.42	0.42
Electricity	3.91	4.50	4.24	4.34	4.96	4.55	4.57	5.80	5.38	5.38
Delivered Energy	**10.62**	**11.86**	**11.44**	**11.62**	**12.42**	**11.71**	**11.79**	**13.80**	**13.13**	**13.10**
Electricity Related Losses	8.46	9.46	8.55	8.95	9.88	8.68	8.76	10.58	9.27	9.18
Total	**19.08**	**21.32**	**20.00**	**20.57**	**22.30**	**20.39**	**20.55**	**24.38**	**22.40**	**22.29**
Commercial										
Distillate Fuel	0.36	0.41	0.42	0.41	0.41	0.47	0.44	0.39	0.51	0.49
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.67	0.66	0.67	0.72	0.70	0.66	0.77	0.75
Natural Gas	3.15	3.71	3.57	3.64	3.89	3.59	3.65	4.12	4.01	3.98
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.07	4.20	4.89	4.49	4.53	5.61	5.16	5.17
Delivered Energy	**7.59**	**8.87**	**8.46**	**8.65**	**9.60**	**8.96**	**9.03**	**10.55**	**10.11**	**10.06**
Electricity Related Losses	8.00	9.15	8.22	8.64	9.74	8.57	8.70	10.23	8.90	8.84
Total	**15.59**	**18.02**	**16.69**	**17.29**	**19.34**	**17.53**	**17.73**	**20.79**	**19.01**	**18.90**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.12	1.12	1.27	1.29	1.27	1.44	1.46	1.46
Liquefied Petroleum Gas	2.32	2.45	2.47	2.45	2.50	2.64	2.66	2.83	3.01	3.09
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.22	0.33	0.23	0.25	0.39	0.38	0.27	0.41	0.41
Motor Gasoline[2]	0.21	0.23	0.22	0.23	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.49	4.49	4.49	4.76	4.84	4.85	5.25	5.41	5.42
Petroleum Subtotal	9.39	9.95	10.04	9.93	10.55	10.93	10.92	11.78	12.26	12.36
Natural Gas[6]	9.43	10.42	10.33	10.45	11.11	10.81	10.83	12.33	12.30	12.02
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.60	0.60	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.84	1.83	1.85	1.93	1.91	1.89	2.00	2.00
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.15	0.22	0.23	0.23
Coal Subtotal	2.54	2.62	2.64	2.63	2.61	2.69	2.67	2.62	2.72	2.72
Renewable Energy[7]	2.15	2.42	2.39	2.40	2.64	2.64	2.63	3.08	3.12	3.12
Electricity	3.63	3.90	3.77	3.82	4.19	3.94	3.96	4.81	4.29	4.34
Delivered Energy	**27.15**	**29.32**	**29.17**	**29.24**	**31.10**	**31.01**	**31.01**	**34.62**	**34.70**	**34.55**
Electricity Related Losses	7.85	8.22	7.60	7.88	8.34	7.51	7.59	8.78	7.40	7.41
Total	**35.00**	**37.53**	**36.77**	**37.12**	**39.45**	**38.51**	**38.60**	**43.40**	**42.09**	**41.96**

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Transportation										
Distillate Fuel	5.13	6.28	6.13	6.19	6.99	6.87	6.84	8.21	8.09	8.08
Jet Fuel[8]	3.46	3.90	3.85	3.87	4.51	4.49	4.48	5.97	5.96	5.96
Motor Gasoline[2]	15.92	17.70	17.59	17.64	19.05	18.94	18.94	21.32	21.24	21.25
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	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	28.75	28.88	31.75	31.50	31.47	36.77	36.57	36.56
Pipeline Fuel Natural Gas	0.66	0.77	0.87	0.82	0.89	0.98	1.00	1.08	1.20	1.20
Compressed Natural Gas	0.02	0.06	0.05	0.06	0.09	0.09	0.09	0.16	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	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**	**29.99**	**29.78**	**29.86**	**32.89**	**32.72**	**32.71**	**38.23**	**38.13**	**38.13**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.22	0.23	0.30	0.29	0.28
Total	**26.41**	**30.18**	**29.96**	**30.04**	**33.12**	**32.94**	**32.94**	**38.53**	**38.41**	**38.41**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.56	8.61	9.47	9.44	9.37	10.80	10.82	10.79
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.85	3.87	4.51	4.49	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.05	3.03	3.05	3.20	3.22	3.38	3.58	3.66
Motor Gasoline[2]	16.17	17.96	17.84	17.89	19.32	19.21	19.22	21.63	21.55	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.17	1.28	1.18	1.21	1.34	1.34	1.25	1.38	1.38
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.12	5.13	5.58	5.74	5.75
Petroleum Subtotal	36.95	41.08	40.89	40.89	44.26	44.46	44.40	50.42	50.85	50.91
Natural Gas[6]	18.11	20.42	20.12	20.34	21.67	20.84	21.00	24.00	23.70	23.36
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.60	0.60	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.96	1.95	1.98	2.05	2.04	2.02	2.12	2.12
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.15	0.22	0.23	0.23
Coal Subtotal	2.65	2.74	2.76	2.75	2.74	2.81	2.80	2.74	2.85	2.85
Renewable Energy[13]	2.65	2.95	2.92	2.93	3.19	3.18	3.17	3.65	3.66	3.67
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.16	12.45	14.15	13.10	13.17	16.39	15.00	15.05
Delivered Energy	**71.65**	**80.04**	**78.85**	**79.37**	**86.01**	**84.39**	**84.54**	**97.20**	**96.06**	**95.85**
Electricity Related Losses	24.44	27.02	24.56	25.65	28.20	24.98	25.28	29.89	25.85	25.71
Total	**96.09**	**107.05**	**103.41**	**105.02**	**114.21**	**109.37**	**109.82**	**127.10**	**121.91**	**121.56**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.04	0.03	0.04	0.03	0.03	0.04	0.02	0.02
Residual Fuel	1.07	0.27	0.17	0.17	0.13	0.10	0.09	0.14	0.08	0.08
Petroleum Subtotal	1.13	0.32	0.22	0.20	0.17	0.13	0.12	0.19	0.10	0.10
Natural Gas	3.79	5.36	9.46	7.26	6.84	11.38	12.03	11.40	15.65	15.93
Steam Coal	18.81	21.63	13.19	16.75	22.80	10.57	9.97	23.73	8.29	8.21
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.37	7.32
Renewable Energy[15]	3.86	4.03	5.34	5.38	4.47	7.58	7.93	4.56	9.06	8.83
Electricity Imports[16]	0.35	0.61	0.62	0.61	0.37	0.51	0.50	0.24	0.37	0.37
Total	**35.73**	**39.85**	**36.72**	**38.10**	**42.35**	**38.08**	**38.45**	**46.28**	**40.85**	**40.76**

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.60	8.64	9.51	9.46	9.40	10.84	10.84	10.81
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.85	3.87	4.51	4.49	4.48	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.05	3.03	3.05	3.20	3.22	3.38	3.58	3.66
Motor Gasoline[2]	16.17	17.96	17.84	17.89	19.32	19.21	19.22	21.63	21.55	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.52	1.70	1.69	1.69
Residual Fuel	2.12	1.44	1.45	1.35	1.34	1.44	1.43	1.39	1.46	1.46
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.12	5.13	5.58	5.74	5.75
Petroleum Subtotal	38.07	41.40	41.11	41.09	44.43	44.59	44.52	50.60	50.95	51.01
Natural Gas	21.90	25.78	29.58	27.61	28.52	32.21	33.03	35.40	39.36	39.29
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.60	0.60	0.50	0.50	0.50
Steam Coal	20.65	23.57	15.15	18.70	24.77	12.62	12.01	25.75	10.42	10.33
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.15	0.22	0.23	0.23
Coal Subtotal	21.46	24.37	15.94	19.50	25.54	13.38	12.76	26.48	11.14	11.05
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.37	7.32
Renewable Energy[17]	6.51	6.98	8.26	8.31	7.66	10.76	11.10	8.21	12.72	12.50
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.62	0.61	0.37	0.51	0.50	0.24	0.37	0.37
Total	**96.09**	**107.05**	**103.41**	**105.02**	**114.21**	**109.37**	**109.82**	**127.10**	**121.91**	**121.56**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	78.85	79.37	86.01	84.39	84.54	97.20	96.06	95.85
Total Energy Use	96.09	107.05	103.41	105.02	114.21	109.37	109.82	127.10	121.91	121.56
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	10834	10885	12667	12628	12606	16515	16521	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1528.0	1589.9	1816.2	1560.6	1555.1	2045.4	1714.7	1712.6

[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.

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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Residential	**13.12**	**12.91**	**15.21**	**14.24**	**13.15**	**16.55**	**16.38**	**13.59**	**16.27**	**16.39**
Primary Energy[1]	6.72	7.12	7.74	7.44	7.00	8.23	8.03	7.02	7.92	8.02
Petroleum Products[2]	7.55	9.18	9.18	9.18	9.37	9.36	9.29	9.66	9.73	9.79
Distillate Fuel	6.27	7.34	7.33	7.33	7.51	7.46	7.46	7.99	8.01	8.01
Liquefied Petroleum Gas	10.36	12.83	12.85	12.84	13.06	13.09	12.88	12.90	13.03	13.23
Natural Gas	6.52	6.63	7.41	7.04	6.52	8.02	7.79	6.56	7.59	7.71
Electricity	23.46	21.84	27.16	24.96	21.88	28.85	28.80	22.16	27.66	27.76
Commercial	**13.20**	**12.36**	**16.10**	**14.48**	**11.74**	**16.45**	**16.16**	**12.37**	**15.67**	**15.88**
Primary Energy[1]	5.22	5.35	6.00	5.69	5.53	6.72	6.55	5.76	6.59	6.70
Petroleum Products[2]	5.00	6.01	5.99	6.00	6.17	6.07	6.07	6.52	6.41	6.46
Distillate Fuel	4.37	5.13	5.11	5.12	5.28	5.22	5.22	5.77	5.75	5.77
Residual Fuel	2.63	3.64	3.62	3.62	3.69	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.31	6.09	5.72	5.49	6.96	6.74	5.72	6.73	6.85
Electricity	21.43	19.51	26.78	23.64	17.61	25.95	25.53	18.09	24.23	24.41
Industrial[4]	**5.32**	**5.49**	**6.54**	**6.07**	**5.44**	**6.91**	**6.78**	**5.85**	**6.86**	**6.98**
Primary Energy	3.92	4.25	4.62	4.43	4.37	5.05	4.94	4.73	5.22	5.32
Petroleum Products[2]	5.55	5.95	5.94	5.95	6.05	6.10	6.04	6.28	6.36	6.45
Distillate Fuel	4.65	5.29	5.29	5.29	5.46	5.41	5.40	5.98	5.98	6.01
Liquefied Petroleum Gas	8.50	7.94	8.00	7.96	8.00	8.21	8.00	7.86	8.15	8.35
Residual Fuel	2.78	3.37	3.25	3.35	3.42	3.34	3.33	3.58	3.49	3.49
Natural Gas[5]	2.79	3.17	4.05	3.62	3.30	4.84	4.64	3.77	4.84	4.97
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.54	1.54	1.44	1.43	1.44
Steam Coal	1.43	1.34	1.27	1.31	1.29	1.19	1.18	1.21	1.07	1.06
Electricity	13.01	12.30	17.44	15.27	11.21	17.65	17.32	11.60	16.46	16.54
Transportation	**8.30**	**9.27**	**9.31**	**9.29**	**9.45**	**9.56**	**9.54**	**9.32**	**9.34**	**9.34**
Primary Energy	8.29	9.25	9.29	9.27	9.44	9.53	9.52	9.30	9.31	9.32
Petroleum Products[2]	8.28	9.25	9.29	9.27	9.44	9.52	9.51	9.30	9.30	9.31
Distillate Fuel[6]	8.22	8.89	8.90	8.90	8.94	8.92	8.92	9.02	9.03	9.07
Jet Fuel[7]	4.70	5.24	5.23	5.23	5.46	5.46	5.46	5.88	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.70	10.66	10.92	11.07	11.05	10.68	10.68	10.68
Residual Fuel	2.46	3.10	3.11	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.30	14.24	14.24	14.37	14.22	13.88	14.03	14.22
Natural Gas[10]	7.02	6.80	7.63	7.22	7.03	8.50	8.33	7.33	8.31	8.41
Ethanol (E85)[11]	14.42	19.12	19.21	19.15	19.00	19.27	19.22	19.36	19.50	19.51
Methanol (M85)[12]	10.38	13.11	13.84	13.27	13.74	14.25	14.24	14.43	14.42	14.42
Electricity	15.58	14.29	16.82	15.66	13.53	16.57	16.54	13.03	15.08	15.12
Average End-Use Energy	**8.53**	**8.90**	**10.02**	**9.54**	**8.94**	**10.45**	**10.35**	**9.17**	**10.22**	**10.31**
Primary Energy	6.33	7.00	7.26	7.13	7.18	7.65	7.58	7.31	7.61	7.67
Electricity	19.40	18.10	23.95	21.47	17.18	24.38	24.12	17.57	23.14	23.24
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	2.21	1.75	1.52	2.85	2.84	1.85	3.37	3.48
Petroleum Products	2.50	3.70	3.80	3.79	4.06	4.13	4.18	4.33	4.62	4.66
Distillate Fuel	4.04	4.65	4.68	4.68	4.85	4.82	4.82	5.30	5.26	5.27
Residual Fuel	2.41	3.52	3.59	3.62	3.85	3.94	3.98	4.04	4.44	4.48
Natural Gas	2.54	2.89	3.89	3.35	3.02	4.63	4.43	3.61	4.72	4.85
Steam Coal	1.22	1.13	0.99	1.02	1.05	0.92	0.91	0.98	0.82	0.81

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.46	8.46	8.63	8.68	8.66	8.62	8.63	8.66
Distillate Fuel	7.27	8.07	8.06	8.07	8.18	8.12	8.13	8.41	8.39	8.43
Jet Fuel	4.70	5.24	5.23	5.23	5.46	5.46	5.46	5.88	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.89	8.86	8.87	9.03	8.81	8.64	8.89	9.07
Motor Gasoline[8]	9.45	10.64	10.70	10.66	10.92	11.07	11.05	10.68	10.68	10.68
Residual Fuel	2.48	3.26	3.23	3.25	3.33	3.31	3.31	3.49	3.48	3.48
Natural Gas	4.05	4.25	4.93	4.58	4.27	5.60	5.38	4.52	5.47	5.60
Coal	1.24	1.15	1.02	1.05	1.07	0.96	0.96	1.00	0.87	0.86
Ethanol (E85)[11]	14.42	19.12	19.21	19.15	19.00	19.27	19.22	19.36	19.50	19.51
Methanol (M85)[12]	10.38	13.11	13.84	13.27	13.74	14.25	14.24	14.43	14.42	14.42
Electricity	19.40	18.10	23.95	21.47	17.18	24.38	24.12	17.57	23.14	23.24
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	167.57	159.41	157.75	186.79	186.11	181.60	206.82	207.83
Commercial	99.10	108.63	134.92	124.07	111.63	146.05	144.67	129.48	157.13	158.50
Industrial	110.62	121.27	145.04	134.69	126.35	162.03	158.69	151.05	178.64	181.09
Transportation	212.64	270.40	268.97	269.40	301.90	302.66	302.02	345.30	343.93	344.18
Total Non-Renewable Expenditures	556.41	647.83	716.50	687.57	697.64	797.53	791.49	807.43	886.52	891.60
Transportation Renewable Expenditures	0.14	0.42	0.41	0.41	0.61	0.62	0.61	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**716.91**	**687.99**	**698.25**	**798.15**	**792.10**	**808.29**	**887.38**	**892.46**

[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	1319	1656	2232	1061	1003	2317	835	825
Petroleum	104	32	23	21	18	14	13	19	11	11
Natural Gas[2]	365	574	1075	827	867	1527	1603	1568	2201	2271
Nuclear Power	730	740	740	740	720	741	741	577	690	686
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	439	444	384	530	537	390	659	626
Total	**3386**	**3811**	**3594**	**3687**	**4220**	**3872**	**3896**	**4872**	**4396**	**4418**
Non-Utility Generation for Own Use	16	16	22	21	16	21	20	16	20	20
Distributed Generation	0	1	0	0	3	0	0	6	0	0
Cogenerators[4]										
Coal	47	52	52	52	52	52	52	52	51	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	265	256	256	331	319	298	503	477
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	33	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**372**	**363**	**369**	**444**	**432**	**421**	**626**	**600**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	150	171	179	177	176	191	191	200	246	239
Generation for Own Use	156	180	197	191	198	258	246	226	384	366
Net Imports[8]	**33**	**57**	**59**	**57**	**35**	**49**	**47**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1146	1317	1242	1273	1452	1335	1339	1699	1576	1575
Commercial	1083	1275	1194	1230	1432	1317	1329	1644	1513	1516
Industrial	1063	1144	1104	1121	1227	1154	1159	1411	1258	1271
Transportation	17	26	26	26	35	34	34	49	48	48
Total	**3309**	**3762**	**3565**	**3649**	**4146**	**3839**	**3861**	**4803**	**4396**	**4411**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	9.3	8.5	7.5	9.8	9.8	7.6	9.4	9.5
Commercial	7.3	6.7	9.1	8.1	6.0	8.9	8.7	6.2	8.3	8.3
Industrial	4.4	4.2	6.0	5.2	3.8	6.0	5.9	4.0	5.6	5.6
Transportation	5.3	4.9	5.7	5.3	4.6	5.7	5.6	4.4	5.1	5.2
All Sectors Average	**6.6**	**6.2**	**8.2**	**7.3**	**5.9**	**8.3**	**8.2**	**6.0**	**7.9**	**7.9**
Prices by Service Category[9] **(1999 cents per kwh)**										
Generation	4.1	3.6	5.5	4.7	3.2	5.5	5.4	3.4	5.2	5.2
Transmission	0.6	0.6	0.7	0.7	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	13.82	10.39	9.30	10.39	9.70	8.09	7.77	8.95	6.68	6.61
Nitrogen Oxide	5.46	4.22	3.07	3.58	4.20	2.47	2.33	4.37	2.01	1.95

[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Table C5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	297.9	298.2	317.4	261.9	269.3	317.8	240.6	236.7
Other Fossil Steam[3]	138.2	129.6	124.5	124.0	121.1	102.6	105.2	117.2	96.3	93.0
Combined Cycle	20.2	49.4	85.7	70.5	124.0	182.0	185.6	230.0	269.9	282.4
Combustion Turbine/Diesel	75.6	129.7	106.7	111.8	162.1	111.8	123.1	207.7	157.6	163.7
Nuclear Power	97.4	97.5	97.5	97.5	94.2	96.9	96.9	71.6	89.2	88.4
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]	88.1	91.5	97.0	96.3	94.8	108.7	109.4	96.3	142.2	134.2
Distributed Generation[5]	0.0	2.0	1.8	2.3	6.1	2.8	4.0	14.0	5.8	6.7
Total	**745.0**	**821.5**	**830.5**	**820.0**	**939.4**	**886.1**	**913.0**	**1074.3**	**1021.4**	**1024.9**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	0.0	0.0	20.1	0.0	0.0	21.5	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	20.8	57.1	41.9	95.7	153.9	157.2	201.6	242.0	254.4
Combustion Turbine/Diesel	0.0	57.0	35.3	40.3	90.8	43.7	53.5	137.2	89.9	95.8
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	0.6	6.1	5.4	1.9	15.8	16.6	2.4	48.3	40.3
Distributed Generation[5]	0.0	2.0	1.8	2.3	6.1	2.8	4.0	14.0	5.8	6.7
Total	**0.0**	**82.9**	**100.3**	**89.9**	**214.6**	**216.3**	**231.2**	**376.7**	**386.0**	**397.2**
Cumulative Total Additions	**0.0**	**94.5**	**111.9**	**101.5**	**228.1**	**229.8**	**244.8**	**391.4**	**400.8**	**412.0**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	8.6	8.3	9.2	44.6	37.2	10.2	65.9	69.8
Other Fossil Steam[3]	0.0	8.5	13.6	14.1	17.0	35.5	32.9	20.9	41.8	45.1
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.6	0.3	0.3	0.8	0.6
Combustion Turbine/Diesel	0.0	3.8	4.6	4.5	5.1	7.9	6.4	5.9	8.2	8.1
Nuclear Power	0.0	0.0	0.0	0.0	3.3	0.6	0.6	25.9	8.3	9.1
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**	**19.0**	**26.9**	**27.1**	**34.9**	**89.4**	**77.5**	**63.4**	**125.1**	**132.8**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	42.7	41.7	42.9	52.6	50.7	48.8	76.6	73.2
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	1.1
Renewable Sources[4]	5.3	5.9	5.8	5.8	6.8	6.8	6.7	8.2	8.3	8.4
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**51.6**	**59.2**	**61.8**	**60.8**	**63.1**	**72.8**	**70.9**	**70.7**	**98.6**	**95.3**
Cumulative Additions[6]	**0.0**	**7.5**	**10.1**	**9.2**	**11.4**	**21.2**	**19.3**	**19.0**	**47.0**	**43.7**

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

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 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.
[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.

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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Table C6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 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	147.8	202.8	55.9	93.3	183.2	125.6	103.1	206.7	162.0	159.6
Gross Domestic Trade	**330.0**	**328.1**	**181.2**	**218.5**	**286.1**	**228.5**	**206.0**	**206.7**	**162.0**	**159.6**
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)	4292.5	6044.9	2690.3	3715.2	4987.6	6058.6	4798.0	6227.5	7388.7	7277.4
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**8596.1**	**9621.0**	**9838.8**	**10909.8**	**9649.2**	**6227.5**	**7388.7**	**7277.4**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	11.8	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**	**75.3**	**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**

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[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Table C7. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Production										
Dry Gas Production[1]	18.67	20.72	23.46	21.72	23.03	25.25	25.98	28.84	30.79	30.82
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**	**4.47**	**5.46**	**5.26**	**4.94**	**6.36**	**6.43**	**5.83**	**7.77**	**7.68**
Canada	3.29	4.28	4.69	4.51	4.68	5.27	5.36	5.46	6.10	6.11
Mexico	-0.01	-0.18	0.30	0.30	-0.25	0.32	0.32	-0.40	0.36	0.36
Liquefied Natural Gas	0.10	0.37	0.47	0.45	0.51	0.77	0.74	0.77	1.31	1.22
Total Supply	**22.15**	**25.30**	**29.03**	**27.09**	**28.03**	**31.67**	**32.46**	**34.72**	**38.62**	**38.56**
Consumption by Sector										
Residential	4.72	5.32	5.16	5.24	5.54	5.23	5.29	6.14	5.88	5.86
Commercial	3.07	3.62	3.48	3.55	3.78	3.50	3.55	4.02	3.91	3.87
Industrial[3]	7.95	8.80	8.58	8.78	9.33	8.93	8.91	10.17	10.06	9.78
Electric Generators[4]	3.72	5.26	9.28	7.13	6.72	11.17	11.80	11.19	15.36	15.63
Lease and Plant Fuel[5]	1.23	1.35	1.48	1.39	1.49	1.60	1.63	1.83	1.93	1.93
Pipeline Fuel	0.64	0.75	0.84	0.80	0.87	0.95	0.98	1.06	1.17	1.17
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.14	0.14
Total	**21.35**	**25.14**	**28.87**	**26.94**	**27.82**	**31.46**	**32.25**	**34.55**	**38.44**	**38.38**
Discrepancy[7]	**0.80**	**0.16**	**0.16**	**0.15**	**0.21**	**0.21**	**0.21**	**0.17**	**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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A. 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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	3.45	2.97	2.68	4.36	4.13	3.14	4.22	4.38
Average Import Price	2.29	2.48	2.82	2.71	2.41	2.92	2.85	2.67	3.23	3.25
Average[2]	**2.11**	**2.49**	**3.33**	**2.92**	**2.63**	**4.07**	**3.87**	**3.05**	**4.02**	**4.15**
Delivered Prices										
Residential	6.69	6.81	7.61	7.23	6.70	8.23	8.00	6.74	7.80	7.92
Commercial	5.49	5.45	6.26	5.87	5.64	7.15	6.93	5.87	6.91	7.04
Industrial[3]	2.87	3.26	4.16	3.72	3.39	4.97	4.76	3.87	4.97	5.11
Electric Generators[4]	2.59	2.94	3.97	3.41	3.08	4.72	4.51	3.68	4.81	4.95
Transportation[5]	7.21	6.99	7.83	7.41	7.22	8.73	8.55	7.53	8.53	8.64
Average[6]	**4.16**	**4.36**	**5.05**	**4.70**	**4.38**	**5.75**	**5.52**	**4.64**	**5.61**	**5.74**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.28	4.31	4.07	4.16	4.13	3.69	3.78	3.77
Commercial	3.37	2.96	2.93	2.96	3.01	3.08	3.05	2.82	2.90	2.88
Industrial[3]	0.75	0.76	0.83	0.80	0.76	0.90	0.89	0.82	0.95	0.95
Electric Generators[4]	0.48	0.45	0.63	0.50	0.45	0.65	0.64	0.63	0.79	0.79
Transportation[5]	5.10	4.49	4.50	4.49	4.59	4.66	4.68	4.48	4.51	4.49
Average[6]	**2.05**	**1.87**	**1.72**	**1.78**	**1.75**	**1.68**	**1.65**	**1.59**	**1.59**	**1.59**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.10	22.59	22.55	21.77	21.85	22.62	22.22	22.07
Commercial	10.36	10.71	10.17	10.49	11.40	10.76	10.84	11.32	11.32	11.17
Industrial[3]	6.00	6.72	7.11	7.04	7.10	8.01	7.91	8.34	9.56	9.33
Electric Generators[4]	1.77	2.35	5.89	3.55	3.03	7.28	7.56	7.00	12.10	12.40
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.40	0.41	0.69	0.64	0.64
Total	**39.82**	**42.98**	**45.51**	**43.91**	**44.49**	**48.22**	**48.58**	**49.97**	**55.85**	**55.60**

[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Table C9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	CO$_2$ Cap 2005	CO$_2$ Cap 2008	Reference	CO$_2$ Cap 2005	CO$_2$ Cap 2008	Reference	CO$_2$ Cap 2005	CO$_2$ Cap 2008
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.39**	**20.39**	**20.81**	**20.72**	**20.73**	**21.46**	**21.46**	**21.46**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.56**	**5.56**	**5.15**	**5.16**	**5.11**	**5.01**	**5.42**	**5.36**
Lower 48 Onshore	3.27	2.75	2.77	2.76	2.49	2.56	2.53	2.63	2.74	2.75
Conventional	2.59	2.15	2.17	2.16	1.82	1.95	1.90	1.91	2.10	2.10
Enhanced Oil Recovery	0.68	0.61	0.60	0.60	0.66	0.61	0.63	0.72	0.64	0.65
Lower 48 Offshore	1.56	2.05	2.00	2.00	2.02	1.95	1.94	1.75	2.04	1.97
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.43**	**15.39**	**14.03**	**14.17**	**14.10**	**13.43**	**14.44**	**14.40**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**3.45**	**2.97**	**2.68**	**4.36**	**4.13**	**3.14**	**4.22**	**4.38**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**23.46**	**21.72**	**23.03**	**25.25**	**25.98**	**28.84**	**30.79**	**30.82**
Lower 48 Onshore	12.83	14.33	16.43	15.03	16.32	18.24	18.93	21.20	22.66	22.54
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.41	1.37	1.35	1.42	1.42
Non-Associated	11.03	12.82	14.92	13.52	14.98	16.84	17.56	19.85	21.24	21.11
Conventional	6.64	7.19	8.72	7.74	8.31	9.37	9.71	11.38	10.70	10.86
Unconventional	4.39	5.62	6.20	5.79	6.66	7.47	7.85	8.48	10.54	10.25
Lower 48 Offshore	5.43	5.93	6.56	6.22	6.21	6.51	6.55	7.07	7.57	7.72
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.05	1.05	1.01	1.07	1.06
Non-Associated	4.50	4.85	5.49	5.15	5.13	5.46	5.50	6.06	6.50	6.66
Alaska	0.42	0.47	0.46	0.46	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**166.23**	**167.30**	**168.05**	**174.58**	**187.43**	**183.45**	**188.20**	**224.01**	**219.68**
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)	**17.94**	**24.11**	**29.88**	**28.03**	**28.67**	**39.70**	**38.22**	**39.25**	**50.71**	**52.47**

[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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Production[1]										
Appalachia	434	422	318	362	412	270	262	395	220	218
Interior	185	180	135	161	177	109	105	163	97	96
West	485	633	352	463	708	302	284	784	256	256
East of the Mississippi	561	554	418	477	545	357	349	525	298	295
West of the Mississippi	543	681	387	508	752	323	302	817	276	275
Total	**1105**	**1235**	**805**	**986**	**1297**	**681**	**651**	**1342**	**574**	**570**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	57	56	56	57	57
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-48**	**-47**	**-36**	**-48**	**-48**
Total Supply[2]	**1055**	**1191**	**757**	**938**	**1256**	**633**	**604**	**1306**	**525**	**521**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	84	84	84	88	87	86	92	92
Coke Plants	28	26	26	26	23	23	23	19	19	19
Electric Generators[4]	922	1078	646	825	1145	518	488	1198	410	406
Total	**1034**	**1192**	**761**	**939**	**1257**	**634**	**603**	**1308**	**525**	**521**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**-4**	**-2**	**-1**	**-1**	**1**	**-2**	**0**	**0**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	14.78	14.82	13.69	13.77	13.72	12.84	12.55	12.54
(1999 dollars per million Btu)	0.82	0.72	0.70	0.71	0.67	0.65	0.64	0.63	0.59	0.59
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	27.89	28.74	28.41	26.08	25.86	26.55	23.28	23.21
Coke Plants	44.20	42.47	42.55	42.62	41.29	41.31	41.18	38.57	38.38	38.57
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	20.12	20.79	20.84	18.75	18.55	19.40	16.51	16.35
(1999 dollars per million Btu)	1.22	1.13	0.99	1.02	1.05	0.92	0.91	0.98	0.82	0.81
Average	**25.82**	**23.53**	**21.74**	**22.10**	**21.72**	**20.58**	**20.47**	**20.15**	**18.48**	**18.37**
Exports[7]	37.43	36.32	35.65	36.14	35.54	34.33	34.07	33.13	31.13	31.23

[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.

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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	80.14	79.92	78.74	80.26	80.21	78.74	80.46	80.26
Geothermal[2]	2.87	3.16	5.73	5.59	4.31	13.08	15.03	4.34	14.22	15.10
Municipal Solid Waste[3]	2.59	3.15	3.92	3.76	3.56	4.37	4.33	4.07	4.90	4.90
Wood and Other Biomass[4]	1.52	1.68	1.98	1.92	2.04	2.99	2.55	2.37	11.74	7.89
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.76	4.64	5.51	7.37	6.71	5.78	29.85	25.06
Total	**88.07**	**91.47**	**96.96**	**96.28**	**94.76**	**108.68**	**109.42**	**96.33**	**142.19**	**134.24**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	304.22	303.50	298.99	304.14	303.97	297.94	303.61	303.06
Geothermal[2]	13.07	15.90	45.69	44.67	24.98	103.65	118.99	25.33	112.69	119.63
Municipal Solid Waste[3]	18.05	22.30	28.28	27.04	24.94	31.36	30.99	28.85	35.39	35.40
Wood and Other Biomass[4]	8.86	14.45	49.07	58.04	21.55	71.33	65.91	22.15	118.76	92.51
Dedicated Plants	7.56	8.67	10.71	10.35	10.88	17.28	14.32	13.35	75.87	50.17
Cofiring	1.30	5.78	38.36	47.70	10.67	54.05	51.59	8.80	42.89	42.33
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	4.46	9.42	10.35	10.02	12.33	17.63	15.73	13.10	85.87	72.59
Total	**352.79**	**362.28**	**438.78**	**444.45**	**384.41**	**529.74**	**537.22**	**390.09**	**659.04**	**625.92**
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	5.09	5.13	6.06	6.06	6.04	7.54	7.61	7.66
Total	**5.35**	**5.87**	**5.79**	**5.83**	**6.76**	**6.76**	**6.74**	**8.23**	**8.31**	**8.36**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.43	29.68	35.01	34.95	34.83	43.52	43.86	44.21
Total	**31.10**	**33.95**	**33.46**	**33.71**	**39.03**	**38.98**	**38.86**	**47.55**	**47.88**	**48.23**
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**	**5.17**	**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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.42**	**0.42**	**0.44**	**0.42**	**0.42**
Wood	0.41	0.43	0.43	0.43	0.43	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**	**2.39**	**2.40**	**2.64**	**2.64**	**2.63**	**3.08**	**3.12**	**3.12**
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	2.21	2.22	2.46	2.46	2.45	2.90	2.93	2.93
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.21	0.21
Electric Generators[5]	**3.86**	**4.03**	**5.34**	**5.38**	**4.47**	**7.58**	**7.93**	**4.56**	**9.06**	**8.83**
Conventional Hydroelectric	3.17	3.08	3.13	3.12	3.08	3.13	3.13	3.06	3.12	3.12
Geothermal	0.27	0.37	1.19	1.16	0.66	3.08	3.51	0.67	3.38	3.53
Municipal Solid Waste[6]	0.25	0.30	0.39	0.37	0.34	0.43	0.42	0.39	0.48	0.48
Biomass	0.12	0.18	0.52	0.61	0.26	0.74	0.69	0.27	1.17	0.93
Dedicated Plants	0.10	0.11	0.11	0.11	0.13	0.18	0.15	0.16	0.75	0.51
Cofiring	0.02	0.07	0.41	0.51	0.13	0.56	0.54	0.11	0.42	0.43
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	0.10	0.11	0.10	0.13	0.18	0.16	0.13	0.88	0.75
Total Marketed Renewable Energy	**6.61**	**7.16**	**8.44**	**8.49**	**7.84**	**10.94**	**11.28**	**8.40**	**12.92**	**12.70**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**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 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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

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 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Residential										
Petroleum	26.0	26.8	26.9	26.9	24.4	24.7	24.7	22.9	23.5	23.4
Natural Gas	69.5	78.6	76.4	77.4	82.0	77.3	78.3	90.8	86.9	86.6
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	192.6	223.2	166.3	187.3	240.4	151.8	149.2	274.7	157.6	157.6
Total	**289.3**	**330.0**	**270.9**	**292.9**	**348.1**	**255.2**	**253.5**	**389.6**	**269.3**	**268.9**
Commercial										
Petroleum	13.7	12.9	13.1	12.9	13.1	14.2	13.7	12.9	15.1	14.8
Natural Gas	45.4	53.5	51.4	52.5	56.0	51.7	52.5	59.4	57.8	57.3
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	159.9	181.0	237.0	149.7	148.1	265.8	151.2	151.7
Total	**242.9**	**284.1**	**226.2**	**248.1**	**307.9**	**217.5**	**216.1**	**340.0**	**226.2**	**225.7**
Industrial[1]										
Petroleum	104.2	99.0	102.0	99.4	104.7	112.2	112.1	115.6	124.6	126.3
Natural Gas[2]	141.6	147.8	146.5	148.1	157.6	153.3	153.6	174.9	174.6	170.5
Coal	55.9	66.5	66.9	66.7	66.3	68.2	67.8	66.4	69.0	69.0
Electricity	178.8	193.9	147.9	164.9	203.0	131.2	129.2	228.1	125.8	127.1
Total	**480.4**	**507.2**	**463.2**	**479.1**	**531.6**	**464.9**	**462.6**	**584.9**	**494.0**	**492.8**
Transportation										
Petroleum[3]	485.8	556.8	550.9	553.3	608.6	603.7	603.2	705.1	700.9	700.9
Natural Gas[4]	9.5	11.8	13.3	12.6	14.1	15.4	15.7	17.9	19.4	19.4
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	3.4	3.8	5.7	3.9	3.8	7.9	4.8	4.9
Total[3]	**498.2**	**573.1**	**567.7**	**569.7**	**628.6**	**623.1**	**622.8**	**730.9**	**725.3**	**725.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	692.9	692.6	750.8	754.9	753.7	856.4	864.2	865.3
Natural Gas	266.0	291.8	287.5	290.6	309.7	297.7	300.1	342.9	338.7	333.8
Coal	58.8	69.6	69.9	69.7	69.5	71.4	70.9	69.6	72.2	72.2
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	637.5	477.6	537.0	686.1	436.5	430.3	776.5	439.5	441.2
Total[3]	**1510.8**	**1694.3**	**1528.0**	**1589.9**	**1816.2**	**1560.6**	**1555.1**	**2045.4**	**1714.7**	**1712.6**
Electric Generators[6]										
Petroleum	20.0	6.8	4.5	4.2	3.5	2.6	2.5	3.9	2.1	2.1
Natural Gas	45.8	77.1	136.2	104.6	98.6	163.9	173.2	164.1	225.4	229.4
Coal	490.5	553.6	336.8	428.2	584.0	270.1	254.6	608.4	211.9	209.8
Total	**556.3**	**637.5**	**477.6**	**537.0**	**686.1**	**436.5**	**430.3**	**776.5**	**439.5**	**441.2**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	697.5	696.8	754.3	757.5	756.2	860.3	866.3	867.4
Natural Gas	311.8	368.9	423.7	395.2	408.2	461.5	473.3	507.1	564.1	563.2
Coal	549.3	623.1	406.8	497.9	653.5	341.5	325.6	678.0	284.1	282.0
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**	**1694.3**	**1528.0**	**1589.9**	**1816.2**	**1560.6**	**1555.1**	**2045.4**	**1714.7**	**1712.6**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.3**	**5.5**	**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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Table C14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008	Reference	CO_2 Cap 2005	CO_2 Cap 2008
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	0.00	0.00	10.76	0.00	0.00	15.24	0.00	0.00
SO_2 Allowance Price										
(1999 dollars per ton)	**0.00**	**177.63**	**0.00**	**21.31**	**169.55**	**0.00**	**0.00**	**246.09**	**0.00**	**0.00**
NO_x Controls (gigawatts)										
Combustion	0.00	65.84	55.88	60.28	66.93	56.02	60.28	67.57	56.02	60.28
SCR post-combustion	0.00	84.31	41.57	54.06	85.97	41.57	54.06	89.75	41.57	54.06
SNCR Post-combustion	0.00	25.36	15.94	22.31	28.78	15.94	22.31	38.69	15.94	22.31
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	348.71	449.97	656.33	291.08	272.88	730.01	246.70	245.87
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	312.81	372.09	453.06	267.92	259.29	438.05	222.16	219.38
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	143.59	163.51	187.25	121.68	119.01	174.20	105.06	104.28

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 MCBASE.D121300A, FDC7B05.D121300A, and FDC7B08.D121300A.

Appendix D

Tables for Integrated Cases with 2005 Emission Caps

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.78	11.78	10.90	10.93	10.95	10.61	11.28	11.47
Natural Gas Plant Liquids	2.62	3.02	3.43	3.41	3.31	3.60	3.60	4.07	4.41	4.37
Dry Natural Gas	19.16	21.26	24.24	24.09	23.63	25.70	25.73	29.59	32.02	31.79
Coal	23.12	25.43	16.90	16.83	26.47	16.24	14.79	27.21	13.55	11.89
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.20	7.32
Renewable Energy[1]	6.50	6.98	8.23	8.20	7.65	10.22	10.34	8.20	11.11	11.95
Other[2]	1.65	0.57	0.35	0.35	0.33	0.30	0.30	0.33	0.34	0.34
Total	**73.30**	**77.01**	**72.83**	**72.58**	**79.98**	**74.90**	**73.62**	**86.18**	**79.90**	**79.14**
Imports										
Crude Oil[3]	18.96	23.21	22.62	22.64	25.22	24.94	24.96	26.48	25.96	25.66
Petroleum Products[4]	4.14	4.85	4.87	4.85	6.46	6.52	6.61	10.77	10.64	10.98
Natural Gas	3.63	4.90	5.73	5.71	5.49	6.61	6.68	6.60	7.97	8.09
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.89	0.89	0.96	0.82	0.82
Total	**27.37**	**34.08**	**34.24**	**34.23**	**38.12**	**38.96**	**39.14**	**44.82**	**45.39**	**45.55**
Exports										
Petroleum[6]	1.98	1.81	1.78	1.77	1.79	1.78	1.80	1.90	1.93	1.94
Natural Gas	0.17	0.33	0.12	0.12	0.43	0.12	0.12	0.63	0.12	0.12
Coal	1.48	1.51	1.52	1.52	1.45	1.50	1.50	1.41	1.44	1.44
Total	**3.62**	**3.64**	**3.42**	**3.42**	**3.67**	**3.40**	**3.42**	**3.94**	**3.50**	**3.50**
Discrepancy[7]	**0.95**	**0.39**	**0.37**	**0.24**	**0.21**	**0.19**	**0.20**	**-0.03**	**0.19**	**0.08**
Consumption										
Petroleum Products[8]	38.07	41.40	41.10	41.10	44.43	44.52	44.62	50.60	50.84	51.02
Natural Gas	21.90	25.78	29.77	29.59	28.52	31.99	32.11	35.40	39.68	39.57
Coal	21.46	24.37	15.64	15.73	25.54	15.11	13.64	26.48	12.39	10.85
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.20	7.32
Renewable Energy[1]	6.51	6.98	8.24	8.21	7.66	10.23	10.34	8.21	11.12	11.96
Other[9]	0.35	0.61	0.62	0.62	0.38	0.52	0.52	0.25	0.38	0.38
Total	**96.09**	**107.05**	**103.28**	**103.15**	**114.21**	**110.27**	**109.14**	**127.10**	**121.60**	**121.10**
Net Imports - Petroleum	**21.12**	**26.26**	**25.72**	**25.73**	**29.88**	**29.68**	**29.77**	**35.36**	**34.67**	**34.70**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	3.45	3.46	2.68	3.83	4.33	3.14	4.04	4.30
Coal Minemouth Price (dollars per ton)	17.23	14.76	12.92	13.07	13.69	11.93	11.82	12.84	10.93	11.18
Average Electric Price (cents per Kwh)	6.6	6.2	8.2	8.1	5.9	7.9	8.4	6.0	7.6	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.

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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.89	0.89	0.81	0.81	0.81	0.75	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	0.46	0.46	0.41	0.42	0.42	0.39	0.42	0.41
Petroleum Subtotal	1.42	1.42	1.43	1.43	1.29	1.31	1.31	1.21	1.25	1.24
Natural Gas	4.85	5.46	5.31	5.30	5.69	5.46	5.38	6.30	6.09	6.02
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.43	0.43	0.43	0.43	0.42	0.42	0.44	0.42	0.42
Electricity	3.91	4.50	4.23	4.24	4.96	4.61	4.55	5.80	5.45	5.38
Delivered Energy	**10.62**	**11.86**	**11.44**	**11.44**	**12.42**	**11.86**	**11.70**	**13.80**	**13.26**	**13.12**
Electricity Related Losses	8.46	9.46	8.51	8.46	9.88	8.86	8.61	10.58	9.06	9.03
Total	**19.08**	**21.32**	**19.95**	**19.90**	**22.30**	**20.72**	**20.31**	**24.38**	**22.32**	**22.15**
Commercial										
Distillate Fuel	0.36	0.41	0.42	0.42	0.41	0.46	0.47	0.39	0.48	0.51
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.67	0.67	0.67	0.71	0.72	0.66	0.74	0.77
Natural Gas	3.15	3.71	3.57	3.57	3.89	3.68	3.60	4.12	4.00	3.98
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.06	4.07	4.89	4.55	4.48	5.61	5.25	5.16
Delivered Energy	**7.59**	**8.87**	**8.45**	**8.45**	**9.60**	**9.09**	**8.96**	**10.55**	**10.14**	**10.08**
Electricity Related Losses	8.00	9.15	8.16	8.12	9.74	8.74	8.48	10.23	8.73	8.66
Total	**15.59**	**18.02**	**16.61**	**16.58**	**19.34**	**17.83**	**17.44**	**20.79**	**18.87**	**18.74**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.12	1.12	1.27	1.27	1.29	1.44	1.45	1.45
Liquefied Petroleum Gas	2.32	2.45	2.47	2.47	2.50	2.59	2.65	2.83	3.03	3.09
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	0.22	0.22	0.33	0.33	0.25	0.37	0.39	0.27	0.31	0.41
Motor Gasoline[2]	0.21	0.23	0.22	0.22	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.49	4.49	4.49	4.76	4.80	4.85	5.25	5.39	5.42
Petroleum Subtotal	9.39	9.95	10.04	10.04	10.55	10.81	10.95	11.78	12.16	12.35
Natural Gas[6]	9.43	10.42	10.34	10.33	11.11	11.03	10.78	12.33	12.32	12.08
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.85	1.85	1.85	1.92	1.92	1.89	1.99	2.00
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.23
Coal Subtotal	2.54	2.62	2.64	2.64	2.61	2.68	2.68	2.62	2.71	2.72
Renewable Energy[7]	2.15	2.42	2.39	2.39	2.64	2.64	2.64	3.08	3.08	3.12
Electricity	3.63	3.90	3.76	3.77	4.19	3.96	3.93	4.81	4.39	4.30
Delivered Energy	**27.15**	**29.32**	**29.18**	**29.17**	**31.10**	**31.12**	**30.98**	**34.62**	**34.67**	**34.58**
Electricity Related Losses	7.85	8.22	7.57	7.53	8.34	7.61	7.45	8.78	7.31	7.22
Total	**35.00**	**37.53**	**36.74**	**36.70**	**39.45**	**38.73**	**38.43**	**43.40**	**41.97**	**41.80**

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Transportation										
Distillate Fuel	5.13	6.28	6.14	6.14	6.99	6.89	6.88	8.21	8.10	8.08
Jet Fuel[8]	3.46	3.90	3.85	3.85	4.51	4.49	4.49	5.97	5.96	5.96
Motor Gasoline[2]	15.92	17.70	17.59	17.60	19.05	18.96	18.95	21.32	21.26	21.25
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	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	28.76	28.76	31.75	31.55	31.51	36.77	36.59	36.56
Pipeline Fuel Natural Gas	0.66	0.77	0.87	0.87	0.89	0.97	0.98	1.08	1.20	1.21
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	0.00	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**	**29.99**	**29.80**	**29.80**	**32.89**	**32.76**	**32.73**	**38.23**	**38.16**	**38.13**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.23	0.22	0.30	0.28	0.28
Total	**26.41**	**30.18**	**29.98**	**29.97**	**33.12**	**32.99**	**32.95**	**38.53**	**38.44**	**38.41**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.57	8.57	9.47	9.43	9.44	10.80	10.79	10.81
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.85	3.85	4.51	4.49	4.49	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.05	3.05	3.05	3.15	3.21	3.38	3.60	3.65
Motor Gasoline[2]	16.17	17.96	17.85	17.85	19.32	19.23	19.22	21.63	21.57	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	1.05	1.17	1.28	1.28	1.21	1.33	1.34	1.25	1.28	1.38
Other Petroleum[12]	4.53	4.76	4.75	4.76	5.04	5.08	5.13	5.58	5.72	5.75
Petroleum Subtotal	36.95	41.08	40.90	40.90	44.26	44.38	44.49	50.42	50.74	50.93
Natural Gas[6]	18.11	20.42	20.15	20.12	21.67	21.23	20.82	24.00	23.76	23.44
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.96	1.96	1.98	2.04	2.05	2.02	2.11	2.13
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.23
Coal Subtotal	2.65	2.74	2.76	2.76	2.74	2.80	2.81	2.74	2.84	2.85
Renewable Energy[13]	2.65	2.95	2.92	2.92	3.19	3.18	3.18	3.65	3.64	3.67
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.14	12.16	14.15	13.23	13.07	16.39	15.25	15.02
Delivered Energy	**71.65**	**80.04**	**78.87**	**78.86**	**86.01**	**84.83**	**84.37**	**97.20**	**96.23**	**95.91**
Electricity Related Losses	24.44	27.02	24.41	24.29	28.20	25.44	24.77	29.89	25.37	25.20
Total	**96.09**	**107.05**	**103.28**	**103.15**	**114.21**	**110.27**	**109.14**	**127.10**	**121.60**	**121.10**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.04	0.04	0.04	0.03	0.03	0.04	0.02	0.02
Residual Fuel	1.07	0.27	0.16	0.16	0.13	0.11	0.11	0.14	0.08	0.08
Petroleum Subtotal	1.13	0.32	0.21	0.20	0.17	0.14	0.14	0.19	0.10	0.10
Natural Gas	3.79	5.36	9.62	9.48	6.84	10.75	11.29	11.40	15.92	16.13
Steam Coal	18.81	21.63	12.89	12.97	22.80	12.30	10.83	23.73	9.55	8.00
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.20	7.32
Renewable Energy[15]	3.86	4.03	5.31	5.29	4.47	7.05	7.16	4.56	7.49	8.29
Electricity Imports[16]	0.35	0.61	0.62	0.62	0.37	0.51	0.51	0.24	0.37	0.37
Total	**35.73**	**39.85**	**36.55**	**36.45**	**42.35**	**38.67**	**37.84**	**46.28**	**40.62**	**40.21**

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.61	8.61	9.51	9.46	9.47	10.84	10.81	10.83
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.85	3.85	4.51	4.49	4.49	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.05	3.05	3.05	3.15	3.21	3.38	3.60	3.65
Motor Gasoline[2]	16.17	17.96	17.85	17.85	19.32	19.23	19.22	21.63	21.57	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	2.12	1.44	1.44	1.44	1.34	1.44	1.45	1.39	1.36	1.45
Other Petroleum[12]	4.53	4.76	4.75	4.76	5.04	5.08	5.13	5.58	5.72	5.75
Petroleum Subtotal	38.07	41.40	41.10	41.10	44.43	44.52	44.62	50.60	50.84	51.02
Natural Gas	21.90	25.78	29.77	29.59	28.52	31.99	32.11	35.40	39.68	39.57
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	20.65	23.57	14.85	14.93	24.77	14.35	12.88	25.75	11.67	10.13
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.23
Coal Subtotal	21.46	24.37	15.64	15.73	25.54	15.11	13.64	26.48	12.39	10.85
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.20	7.32
Renewable Energy[17]	6.51	6.98	8.24	8.21	7.66	10.23	10.34	8.21	11.12	11.96
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.62	0.62	0.37	0.51	0.51	0.24	0.37	0.37
Total	**96.09**	**107.05**	**103.28**	**103.15**	**114.21**	**110.27**	**109.14**	**127.10**	**121.60**	**121.10**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	78.87	78.86	86.01	84.83	84.37	97.20	96.23	95.91
Total Energy Use	96.09	107.05	103.28	103.15	114.21	110.27	109.14	127.10	121.60	121.10
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	10837	10838	12667	12638	12629	16515	16521	16521
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1524.3	1523.7	1816.2	1601.6	1567.5	2045.4	1750.1	1712.4

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[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Residential	**13.12**	**12.91**	**15.23**	**15.20**	**13.15**	**15.85**	**16.57**	**13.59**	**15.83**	**16.28**
Primary Energy[1]	6.72	7.12	7.74	7.75	7.00	7.85	8.20	7.02	7.76	7.98
Petroleum Products[2]	7.55	9.18	9.18	9.18	9.37	9.31	9.37	9.66	9.66	9.75
Distillate Fuel	6.27	7.34	7.33	7.33	7.51	7.47	7.46	7.99	7.97	8.00
Liquefied Petroleum Gas	10.36	12.83	12.84	12.84	13.06	12.91	13.12	12.90	12.83	13.11
Natural Gas	6.52	6.63	7.41	7.42	6.52	7.56	7.99	6.56	7.42	7.67
Electricity	23.46	21.84	27.23	27.12	21.88	27.69	28.97	22.16	26.77	27.55
Commercial	**13.20**	**12.36**	**16.10**	**16.03**	**11.74**	**15.50**	**16.50**	**12.37**	**15.13**	**15.62**
Primary Energy[1]	5.22	5.35	6.00	6.01	5.53	6.35	6.70	5.76	6.46	6.66
Petroleum Products[2]	5.00	6.01	5.99	5.99	6.17	6.06	6.07	6.52	6.41	6.42
Distillate Fuel	4.37	5.13	5.11	5.12	5.28	5.22	5.22	5.77	5.74	5.76
Residual Fuel	2.63	3.64	3.62	3.62	3.69	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.31	6.09	6.10	5.49	6.51	6.93	5.72	6.57	6.81
Electricity	21.43	19.51	26.83	26.64	17.61	24.47	26.13	18.09	23.09	24.01
Industrial[4]	**5.32**	**5.49**	**6.54**	**6.53**	**5.44**	**6.55**	**6.92**	**5.85**	**6.69**	**6.90**
Primary Energy	3.92	4.25	4.61	4.62	4.37	4.81	5.04	4.73	5.13	5.28
Petroleum Products[2]	5.55	5.95	5.93	5.93	6.05	6.02	6.11	6.28	6.34	6.41
Distillate Fuel	4.65	5.29	5.29	5.29	5.46	5.42	5.41	5.98	5.98	6.00
Liquefied Petroleum Gas	8.50	7.94	8.00	8.00	8.00	7.98	8.23	7.86	7.94	8.24
Residual Fuel	2.78	3.37	3.25	3.25	3.42	3.33	3.34	3.58	3.57	3.49
Natural Gas[5]	2.79	3.17	4.05	4.06	3.30	4.36	4.81	3.77	4.66	4.92
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.53	1.54	1.44	1.43	1.43
Steam Coal	1.43	1.34	1.24	1.24	1.29	1.18	1.16	1.21	1.06	1.04
Electricity	13.01	12.30	17.50	17.37	11.21	16.54	17.75	11.60	15.55	16.26
Transportation	**8.30**	**9.27**	**9.31**	**9.32**	**9.45**	**9.56**	**9.55**	**9.32**	**9.33**	**9.34**
Primary Energy	8.29	9.25	9.29	9.29	9.44	9.53	9.52	9.30	9.31	9.32
Petroleum Products[2]	8.28	9.25	9.29	9.29	9.44	9.53	9.52	9.30	9.30	9.31
Distillate Fuel[6]	8.22	8.89	8.90	8.90	8.94	8.93	8.92	9.02	9.04	9.05
Jet Fuel[7]	4.70	5.24	5.23	5.23	5.46	5.46	5.46	5.88	5.87	5.88
Motor Gasoline[8]	9.45	10.64	10.70	10.70	10.92	11.08	11.06	10.68	10.68	10.68
Residual Fuel	2.46	3.10	3.11	3.11	3.18	3.18	3.18	3.33	3.32	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.29	14.29	14.24	14.23	14.43	13.88	13.89	14.11
Natural Gas[10]	7.02	6.80	7.63	7.63	7.03	8.07	8.47	7.33	8.16	8.37
Ethanol (E85)[11]	14.42	19.12	19.21	19.21	19.00	19.20	19.27	19.36	19.47	19.51
Methanol (M85)[12]	10.38	13.11	13.84	13.84	13.74	13.99	14.31	14.43	14.43	14.42
Electricity	15.58	14.29	16.90	16.83	13.53	16.23	16.91	13.03	14.64	15.04
Average End-Use Energy	**8.53**	**8.90**	**10.03**	**10.01**	**8.94**	**10.13**	**10.46**	**9.17**	**10.05**	**10.23**
Primary Energy	6.33	7.00	7.26	7.26	7.18	7.51	7.65	7.31	7.56	7.65
Electricity	19.40	18.10	24.01	23.86	17.18	23.15	24.51	17.57	22.14	22.96
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	2.24	2.22	1.52	2.44	2.80	1.85	3.17	3.47
Petroleum Products	2.50	3.70	3.83	3.83	4.06	4.08	4.08	4.33	4.59	4.64
Distillate Fuel	4.04	4.65	4.67	4.69	4.85	4.82	4.81	5.30	5.25	5.26
Residual Fuel	2.41	3.52	3.61	3.62	3.85	3.89	3.88	4.04	4.43	4.47
Natural Gas	2.54	2.89	3.91	3.91	3.02	4.15	4.60	3.61	4.58	4.80
Steam Coal	1.22	1.13	0.97	0.96	1.05	0.92	0.90	0.98	0.80	0.78

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.46	8.46	8.63	8.67	8.68	8.62	8.62	8.64
Distillate Fuel	7.27	8.07	8.06	8.07	8.18	8.14	8.13	8.41	8.40	8.41
Jet Fuel	4.70	5.24	5.23	5.23	5.46	5.46	5.46	5.88	5.87	5.88
Liquefied Petroleum Gas	8.84	8.83	8.88	8.88	8.87	8.82	9.05	8.64	8.69	8.96
Motor Gasoline[8]	9.45	10.64	10.70	10.70	10.92	11.08	11.06	10.68	10.68	10.68
Residual Fuel	2.48	3.26	3.23	3.23	3.33	3.31	3.31	3.49	3.49	3.47
Natural Gas	4.05	4.25	4.93	4.94	4.27	5.16	5.58	4.52	5.31	5.54
Coal	1.24	1.15	1.00	1.00	1.07	0.96	0.94	1.00	0.85	0.83
Ethanol (E85)[11]	14.42	19.12	19.21	19.21	19.00	19.20	19.27	19.36	19.47	19.51
Methanol (M85)[12]	10.38	13.11	13.84	13.84	13.74	13.99	14.31	14.43	14.43	14.42
Electricity	19.40	18.10	24.01	23.86	17.18	23.15	24.51	17.57	22.14	22.96
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	167.72	167.40	157.75	181.24	186.99	181.60	203.13	206.66
Commercial	99.10	108.63	134.78	134.19	111.63	139.57	146.41	129.48	152.25	156.14
Industrial	110.62	121.27	145.16	144.79	126.35	153.71	162.13	151.05	173.87	178.67
Transportation	212.64	270.40	269.07	269.14	301.90	303.24	302.62	345.30	344.08	344.08
Total Non-Renewable Expenditures	556.41	647.83	716.73	715.53	697.64	777.76	798.15	807.43	873.33	885.54
Transportation Renewable Expenditures	0.14	0.42	0.41	0.41	0.61	0.62	0.61	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**717.14**	**715.94**	**698.25**	**778.37**	**798.77**	**808.29**	**874.19**	**886.40**

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[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	1286	1295	2232	1224	1084	2317	949	801
Petroleum	104	32	22	21	18	15	15	19	11	11
Natural Gas[2]	365	574	1103	1102	867	1419	1509	1568	2294	2285
Nuclear Power	730	740	740	740	720	741	741	577	674	686
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	437	436	384	515	516	390	556	624
Total	**3386**	**3811**	**3587**	**3593**	**4220**	**3913**	**3863**	**4872**	**4483**	**4405**
Non-Utility Generation for Own Use	16	16	22	22	16	20	20	16	20	20
Distributed Generation	0	1	0	0	3	0	0	6	0	0
Cogenerators[4]										
Coal	47	52	52	52	52	51	51	52	50	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	265	265	256	327	331	298	458	490
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	33	33	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**372**	**372**	**369**	**440**	**443**	**421**	**580**	**613**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	150	171	179	179	176	191	190	200	235	240
Generation for Own Use	156	180	198	197	198	254	258	226	350	377
Net Imports[8]	**33**	**57**	**59**	**59**	**35**	**49**	**49**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1146	1317	1240	1242	1452	1351	1332	1699	1597	1578
Commercial	1083	1275	1190	1192	1432	1332	1312	1644	1538	1513
Industrial	1063	1144	1103	1104	1227	1160	1153	1411	1287	1261
Transportation	17	26	26	26	35	34	34	49	49	48
Total	**3309**	**3762**	**3559**	**3564**	**4146**	**3878**	**3832**	**4803**	**4471**	**4401**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	9.3	9.3	7.5	9.4	9.9	7.6	9.1	9.4
Commercial	7.3	6.7	9.2	9.1	6.0	8.3	8.9	6.2	7.9	8.2
Industrial	4.4	4.2	6.0	5.9	3.8	5.6	6.1	4.0	5.3	5.5
Transportation	5.3	4.9	5.8	5.7	4.6	5.5	5.8	4.4	5.0	5.1
All Sectors Average	**6.6**	**6.2**	**8.2**	**8.1**	**5.9**	**7.9**	**8.4**	**6.0**	**7.6**	**7.8**
Prices by Service Category [9] **(1999 cents per kwh)**										
Generation	4.1	3.6	5.6	5.5	3.2	5.1	5.6	3.4	4.9	5.1
Transmission	0.6	0.6	0.7	0.7	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	13.82	10.39	4.67	4.87	9.70	4.22	3.92	8.95	3.27	3.27
Nitrogen Oxide	5.46	4.22	1.38	1.46	4.20	1.37	1.30	4.37	1.18	1.12

[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	299.4	299.0	317.4	265.8	260.2	317.8	240.9	228.4
Other Fossil Steam[3]	138.2	129.6	126.1	126.4	121.1	112.8	111.9	117.2	103.7	90.5
Combined Cycle	20.2	49.4	89.3	93.3	124.0	162.5	177.4	230.0	285.7	277.4
Combustion Turbine/Diesel	75.6	129.7	105.7	106.9	162.1	117.8	115.4	207.7	162.9	188.5
Nuclear Power	97.4	97.5	97.5	97.5	94.2	96.9	96.9	71.6	86.1	88.4
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]	88.1	91.5	96.6	96.5	94.8	104.7	106.5	96.3	118.1	133.9
Distributed Generation[5]	0.0	2.0	1.5	1.5	6.1	2.5	2.4	14.0	7.0	5.2
Total	**745.0**	**821.5**	**835.6**	**840.6**	**939.4**	**882.5**	**890.4**	**1074.3**	**1024.3**	**1031.9**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	0.0	0.0	20.1	0.0	0.0	21.5	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	20.8	60.7	64.7	95.7	134.4	149.4	201.6	257.6	249.4
Combustion Turbine/Diesel	0.0	57.0	34.2	35.4	90.8	49.7	46.6	137.2	95.1	120.4
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	0.6	5.8	5.6	1.9	11.8	13.6	2.4	24.2	40.0
Distributed Generation[5]	0.0	2.0	1.5	1.5	6.1	2.5	2.4	14.0	7.0	5.2
Total	**0.0**	**82.9**	**102.2**	**107.3**	**214.6**	**198.5**	**212.1**	**376.7**	**383.9**	**414.9**
Cumulative Total Additions	**0.0**	**94.5**	**113.8**	**118.9**	**228.1**	**212.0**	**225.6**	**391.4**	**398.6**	**429.7**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	7.1	7.5	9.2	41.2	46.8	10.2	66.1	78.7
Other Fossil Steam[3]	0.0	8.5	12.0	11.7	17.0	25.3	26.2	20.9	34.3	47.6
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.6	0.6	0.3	0.6	0.6
Combusion Turbine/Diesel	0.0	3.8	4.6	4.5	5.1	8.0	7.1	5.9	8.2	7.9
Nuclear Power	0.0	0.0	0.0	0.0	3.3	0.6	0.6	25.9	11.3	9.1
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**	**19.0**	**23.8**	**23.9**	**34.9**	**75.9**	**81.5**	**63.4**	**120.7**	**144.0**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	42.7	42.7	42.9	51.9	52.5	48.8	70.5	75.2
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	1.1
Renewable Sources[4]	5.3	5.9	5.8	5.8	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	**51.6**	**59.2**	**61.8**	**61.8**	**63.1**	**72.1**	**72.7**	**70.7**	**92.5**	**97.3**
Cumulative Additions[6]	**0.0**	**7.5**	**10.2**	**10.1**	**11.4**	**20.5**	**21.1**	**19.0**	**40.9**	**45.7**

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

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
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.

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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
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	147.8	202.8	56.4	56.1	183.2	100.5	100.8	206.7	150.4	156.7
Gross Domestic Trade	**330.0**	**328.1**	**181.7**	**181.4**	**286.1**	**203.5**	**203.7**	**206.7**	**150.4**	**156.7**
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)	4292.5	6044.9	2715.4	2674.9	4987.6	4548.8	4965.5	6227.5	6405.5	6967.3
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**8621.2**	**8580.7**	**9838.8**	**9400.0**	**9816.7**	**6227.5**	**6405.5**	**6967.3**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	11.8	11.8	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**	**75.3**	**75.3**	**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**

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[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D7. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Production										
Dry Gas Production[1]	18.67	20.72	23.62	23.48	23.03	25.05	25.08	28.84	31.21	30.98
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**	**4.47**	**5.47**	**5.46**	**4.94**	**6.34**	**6.41**	**5.83**	**7.67**	**7.79**
Canada	3.29	4.28	4.71	4.70	4.68	5.26	5.32	5.46	6.01	6.12
Mexico	-0.01	-0.18	0.30	0.30	-0.25	0.32	0.32	-0.40	0.36	0.36
Liquefied Natural Gas	0.10	0.37	0.47	0.46	0.51	0.75	0.77	0.77	1.31	1.32
Total Supply	**22.15**	**25.30**	**29.21**	**29.06**	**28.03**	**31.44**	**31.54**	**34.72**	**38.94**	**38.83**
Consumption by Sector										
Residential	4.72	5.32	5.17	5.16	5.54	5.32	5.24	6.14	5.93	5.86
Commercial	3.07	3.62	3.48	3.47	3.78	3.58	3.50	4.02	3.89	3.88
Industrial[3]	7.95	8.80	8.59	8.58	9.33	9.16	8.91	10.17	10.05	9.83
Electric Generators[4]	3.72	5.26	9.44	9.30	6.72	10.55	11.08	11.19	15.62	15.83
Lease and Plant Fuel[5]	1.23	1.35	1.48	1.48	1.49	1.59	1.59	1.83	1.95	1.94
Pipeline Fuel	0.64	0.75	0.85	0.85	0.87	0.95	0.95	1.06	1.17	1.18
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.14	0.14
Total	**21.35**	**25.14**	**29.06**	**28.89**	**27.82**	**31.23**	**31.35**	**34.55**	**38.76**	**38.65**
Discrepancy[7]	**0.80**	**0.16**	**0.15**	**0.17**	**0.21**	**0.21**	**0.19**	**0.17**	**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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B. 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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	3.45	3.46	2.68	3.83	4.33	3.14	4.04	4.30
Average Import Price	2.29	2.48	2.82	2.82	2.41	2.81	2.92	2.67	3.15	3.26
Average[2]	**2.11**	**2.49**	**3.33**	**3.34**	**2.63**	**3.62**	**4.04**	**3.05**	**3.87**	**4.09**
Delivered Prices										
Residential	6.69	6.81	7.61	7.62	6.70	7.76	8.20	6.74	7.62	7.88
Commercial	5.49	5.45	6.26	6.27	5.64	6.68	7.12	5.87	6.74	6.99
Industrial[3]	2.87	3.26	4.16	4.17	3.39	4.48	4.94	3.87	4.79	5.05
Electric Generators[4]	2.59	2.94	3.98	3.99	3.08	4.23	4.69	3.68	4.67	4.89
Transportation[5]	7.21	6.99	7.84	7.84	7.22	8.29	8.69	7.53	8.38	8.60
Average[6]	**4.16**	**4.36**	**5.05**	**5.07**	**4.38**	**5.29**	**5.72**	**4.64**	**5.45**	**5.69**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.28	4.28	4.07	4.14	4.16	3.69	3.76	3.78
Commercial	3.37	2.96	2.93	2.93	3.01	3.06	3.08	2.82	2.88	2.90
Industrial[3]	0.75	0.76	0.83	0.83	0.76	0.86	0.90	0.82	0.92	0.96
Electric Generators[4]	0.48	0.45	0.65	0.65	0.45	0.61	0.64	0.63	0.81	0.80
Transportation[5]	5.10	4.49	4.50	4.50	4.59	4.66	4.65	4.48	4.52	4.51
Average[6]	**2.05**	**1.87**	**1.72**	**1.73**	**1.75**	**1.67**	**1.68**	**1.59**	**1.58**	**1.59**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.11	22.10	22.55	22.03	21.79	22.62	22.26	22.18
Commercial	10.36	10.71	10.18	10.17	11.40	10.96	10.78	11.32	11.20	11.24
Industrial[3]	6.00	6.72	7.12	7.12	7.10	7.84	8.01	8.34	9.27	9.45
Electric Generators[4]	1.77	2.35	6.12	6.01	3.03	6.44	7.14	7.00	12.59	12.64
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.41	0.40	0.69	0.65	0.64
Total	**39.82**	**42.98**	**45.76**	**45.64**	**44.49**	**47.68**	**48.13**	**49.97**	**55.97**	**56.14**

[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.39**	**20.39**	**20.81**	**20.79**	**20.70**	**21.46**	**21.45**	**21.46**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.56**	**5.56**	**5.15**	**5.16**	**5.17**	**5.01**	**5.33**	**5.42**
Lower 48 Onshore	3.27	2.75	2.77	2.77	2.49	2.54	2.57	2.63	2.72	2.75
Conventional	2.59	2.15	2.17	2.17	1.82	1.93	1.95	1.91	2.05	2.10
Enhanced Oil Recovery	0.68	0.61	0.60	0.60	0.66	0.62	0.62	0.72	0.67	0.64
Lower 48 Offshore	1.56	2.05	2.00	2.00	2.02	1.98	1.96	1.75	1.97	2.03
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.43**	**15.43**	**14.03**	**14.25**	**14.22**	**13.43**	**14.28**	**14.51**
Natural Gas										
Lower 48 Average Wellhead Price[3] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**3.45**	**3.46**	**2.68**	**3.83**	**4.33**	**3.14**	**4.04**	**4.30**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**23.62**	**23.48**	**23.03**	**25.05**	**25.08**	**28.84**	**31.21**	**30.98**
Lower 48 Onshore	12.83	14.33	16.57	16.46	16.32	18.05	18.09	21.20	22.93	22.74
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.40	1.41	1.35	1.40	1.42
Non-Associated	11.03	12.82	15.05	14.94	14.98	16.65	16.68	19.85	21.53	21.32
Conventional	6.64	7.19	8.81	8.73	8.31	9.15	9.30	11.38	11.13	10.79
Unconventional	4.39	5.62	6.24	6.21	6.66	7.51	7.38	8.48	10.40	10.53
Lower 48 Offshore	5.43	5.93	6.59	6.56	6.21	6.50	6.49	7.07	7.72	7.68
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.05	1.05	1.01	1.05	1.07
Non-Associated	4.50	4.85	5.52	5.49	5.13	5.44	5.44	6.06	6.66	6.61
Alaska	0.42	0.47	0.46	0.46	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves (trillion cubic feet)	**157.41**	**166.23**	**167.12**	**167.03**	**174.58**	**188.57**	**187.82**	**188.20**	**215.38**	**223.35**
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)	**17.94**	**24.11**	**29.88**	**29.94**	**28.67**	**36.99**	**39.50**	**39.25**	**48.36**	**51.52**

[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Production[1]										
Appalachia	434	422	292	297	412	271	252	395	219	208
Interior	185	180	94	95	177	82	74	163	74	65
West	485	633	435	424	708	440	395	784	370	302
East of the Mississippi	561	554	352	357	545	325	301	525	268	255
West of the Mississippi	543	681	469	459	752	468	419	817	395	319
Total	**1105**	**1235**	**821**	**816**	**1297**	**793**	**721**	**1342**	**663**	**574**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	59	59	56	58	58
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-50**	**-50**	**-36**	**-49**	**-49**
Total Supply[2]	**1055**	**1191**	**773**	**767**	**1256**	**743**	**670**	**1306**	**614**	**526**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	84	84	84	88	88	86	91	92
Coke Plants	28	26	26	26	23	23	23	19	19	18
Electric Generators[4]	922	1078	654	656	1145	628	555	1198	493	410
Total	**1034**	**1192**	**769**	**771**	**1257**	**744**	**670**	**1308**	**609**	**525**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**4**	**-3**	**-1**	**-1**	**-0**	**-2**	**6**	**0**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	12.92	13.07	13.69	11.93	11.82	12.84	10.93	11.18
(1999 dollars per million Btu)	0.82	0.72	0.63	0.63	0.67	0.58	0.58	0.63	0.54	0.54
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	27.06	27.14	28.41	25.79	25.40	26.55	23.08	22.73
Coke Plants	44.20	42.47	42.61	42.61	41.29	41.13	41.24	38.57	38.36	38.35
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	19.05	19.07	20.84	18.03	17.56	19.40	15.54	15.17
(1999 dollars per million Btu)	1.22	1.13	0.97	0.96	1.05	0.92	0.90	0.98	0.80	0.78
Average	**25.82**	**23.53**	**20.72**	**20.75**	**21.72**	**19.66**	**19.40**	**20.15**	**17.38**	**17.33**
Exports[7]	37.43	36.32	35.45	35.51	35.54	34.16	34.01	33.13	31.26	31.00

[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D11. Renewable Energy Generating Capability and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Electric Generators[1]										
(excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	79.92	79.92	78.74	80.04	80.04	78.74	80.04	80.05
Geothermal[2]	2.87	3.16	5.71	5.56	4.31	11.14	11.74	4.34	11.21	12.20
Municipal Solid Waste[3]	2.59	3.15	3.92	3.91	3.56	4.36	4.36	4.07	4.88	4.90
Wood and Other Biomass[4]	1.52	1.68	2.03	2.03	2.04	2.48	3.25	2.37	5.51	11.98
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.59	4.63	5.51	6.04	6.47	5.78	15.43	23.75
Total	**88.07**	**91.47**	**96.61**	**96.49**	**94.76**	**104.66**	**106.48**	**96.33**	**118.08**	**133.90**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	303.48	303.48	298.99	303.40	303.39	297.94	302.33	302.33
Geothermal[2]	13.07	15.90	45.56	44.36	24.98	88.34	93.12	25.33	88.95	96.79
Municipal Solid Waste[3]	18.05	22.30	28.28	28.25	24.94	31.23	31.27	28.85	35.21	35.38
Wood and Other Biomass[4]	8.86	14.45	48.32	48.58	21.55	76.11	71.94	22.15	82.56	118.20
Dedicated Plants	7.56	8.67	11.09	11.08	10.88	13.83	19.00	13.35	34.30	77.46
Cofiring	1.30	5.78	37.23	37.50	10.67	62.28	52.94	8.80	48.26	40.73
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	4.46	9.42	9.88	9.98	12.33	13.85	15.11	13.10	43.86	68.39
Total	**352.79**	**362.28**	**436.68**	**435.82**	**384.41**	**514.54**	**516.46**	**390.09**	**555.64**	**623.82**
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	5.09	5.09	6.06	6.06	6.07	7.54	7.56	7.65
Total	**5.35**	**5.87**	**5.79**	**5.79**	**6.76**	**6.76**	**6.76**	**8.23**	**8.26**	**8.35**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.43	29.44	35.01	34.95	34.96	43.52	43.62	44.12
Total	**31.10**	**33.95**	**33.46**	**33.46**	**39.03**	**38.97**	**38.99**	**47.55**	**47.65**	**48.14**
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	0.76
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.

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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.42**	**0.42**	**0.44**	**0.42**	**0.42**
Wood	0.41	0.43	0.43	0.43	0.43	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**	**2.39**	**2.39**	**2.64**	**2.64**	**2.64**	**3.08**	**3.08**	**3.12**
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	2.21	2.21	2.46	2.45	2.46	2.90	2.90	2.94
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.21	0.21
Electric Generators[5]	**3.86**	**4.03**	**5.31**	**5.29**	**4.47**	**7.05**	**7.16**	**4.56**	**7.49**	**8.29**
Conventional Hydroelectric	3.17	3.08	3.12	3.12	3.08	3.12	3.12	3.06	3.11	3.11
Geothermal	0.27	0.37	1.18	1.15	0.66	2.55	2.69	0.67	2.56	2.81
Municipal Solid Waste[6]	0.25	0.30	0.39	0.39	0.34	0.43	0.43	0.39	0.48	0.48
Biomass	0.12	0.18	0.51	0.51	0.26	0.80	0.75	0.27	0.86	1.16
Dedicated Plants	0.10	0.11	0.12	0.12	0.13	0.15	0.20	0.16	0.36	0.76
Cofiring	0.02	0.07	0.39	0.40	0.13	0.66	0.55	0.11	0.50	0.40
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	0.10	0.10	0.10	0.13	0.14	0.16	0.13	0.45	0.70
Total Marketed Renewable Energy	**6.61**	**7.16**	**8.41**	**8.39**	**7.84**	**10.41**	**10.52**	**8.40**	**11.32**	**12.16**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**

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[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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

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	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Residential										
Petroleum	26.0	26.8	26.9	26.9	24.4	24.7	24.7	22.9	23.5	23.5
Natural Gas	69.5	78.6	76.4	76.3	82.0	78.7	77.4	90.8	87.6	86.7
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	192.6	223.2	165.0	164.8	240.4	165.0	154.2	274.7	170.2	157.6
Total	**289.3**	**330.0**	**269.6**	**269.4**	**348.1**	**269.8**	**257.7**	**389.6**	**282.7**	**269.0**
Commercial										
Petroleum	13.7	12.9	13.1	13.1	13.1	14.0	14.2	12.9	14.5	15.2
Natural Gas	45.4	53.5	51.5	51.4	56.0	52.9	51.8	59.4	57.6	57.3
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	158.2	158.2	237.0	162.7	151.9	265.8	164.0	151.2
Total	**242.9**	**284.1**	**224.6**	**224.5**	**307.9**	**231.5**	**219.7**	**340.0**	**238.0**	**225.7**
Industrial[1]										
Petroleum	104.2	99.0	101.9	101.9	104.7	109.9	112.6	115.6	122.2	126.1
Natural Gas[2]	141.6	147.8	146.7	146.5	157.6	156.5	152.6	174.9	175.0	171.3
Coal	55.9	66.5	67.0	67.0	66.3	67.9	68.0	66.4	68.7	69.1
Electricity	178.8	193.9	146.7	146.6	203.0	141.7	133.4	228.1	137.3	126.0
Total	**480.4**	**507.2**	**462.3**	**462.0**	**531.6**	**476.1**	**466.6**	**584.9**	**503.2**	**492.5**
Transportation										
Petroleum[3]	485.8	556.8	551.1	551.1	608.6	604.7	604.0	705.1	701.4	700.8
Natural Gas[4]	9.5	11.8	13.3	13.3	14.1	15.3	15.3	17.9	19.5	19.6
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	3.4	3.4	5.7	4.2	4.0	7.9	5.2	4.8
Total[3]	**498.2**	**573.1**	**567.9**	**567.9**	**628.6**	**624.3**	**623.4**	**730.9**	**726.2**	**725.3**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	693.0	693.1	750.8	753.3	755.5	856.4	861.7	865.5
Natural Gas	266.0	291.8	287.9	287.5	309.7	303.4	297.2	342.9	339.7	334.9
Coal	58.8	69.6	70.0	70.0	69.5	71.1	71.2	69.6	72.0	72.3
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	637.5	473.4	473.0	686.1	473.7	443.5	776.5	476.7	439.6
Total[3]	**1510.8**	**1694.3**	**1524.3**	**1523.7**	**1816.2**	**1601.6**	**1567.5**	**2045.4**	**1750.1**	**1712.4**
Electric Generators[6]										
Petroleum	20.0	6.8	4.3	4.2	3.5	2.9	2.8	3.9	2.1	2.0
Natural Gas	45.8	77.1	138.6	136.5	98.6	154.8	162.6	164.1	229.2	232.3
Coal	490.5	553.6	330.5	332.4	584.0	315.9	278.1	608.4	245.4	205.3
Total	**556.3**	**637.5**	**473.4**	**473.0**	**686.1**	**473.7**	**443.5**	**776.5**	**476.7**	**439.6**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	697.3	697.2	754.3	756.2	758.3	860.3	863.8	867.5
Natural Gas	311.8	368.9	426.5	423.9	408.2	458.2	459.8	507.1	568.9	567.2
Coal	549.3	623.1	400.4	402.4	653.5	387.0	349.3	678.0	317.3	277.6
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**	**1694.3**	**1524.3**	**1523.7**	**1816.2**	**1601.6**	**1567.5**	**2045.4**	**1750.1**	**1712.4**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.3**	**5.3**	**6.1**	**5.3**	**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.

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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Table D14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005	Reference	Integrated 2005	Integrated -7 2005
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	12.55	9.94	10.76	15.36	9.94	15.24	20.56	16.68
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**246.62**	**201.24**	**169.55**	**220.81**	**226.44**	**246.09**	**162.29**	**98.67**
NO_x Controls (gigawatts)										
Combustion	0.00	65.84	113.11	112.22	66.93	113.11	112.22	67.57	113.11	112.22
SCR Post-combustion	0.00	84.31	157.37	146.83	85.97	157.37	147.16	89.75	157.37	147.16
SNCR Post-combustion	0.00	25.36	55.96	49.31	28.78	55.96	49.48	38.69	55.96	49.48
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	440.89	427.09	656.33	442.65	395.78	730.01	356.86	288.60
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	275.34	282.45	453.06	254.48	236.49	438.05	216.69	204.51
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	105.20	106.26	187.25	95.98	88.25	174.20	89.75	81.27

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 MCBASE.D121300A, FDPOL05.D121300A, and FDP7B05.D121300B.

Appendix E

Tables for Integrated Cases with 2008 Emission Caps

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.81	11.81	10.90	10.92	10.84	10.61	11.21	11.36
Natural Gas Plant Liquids	2.62	3.02	3.17	3.19	3.31	3.66	3.72	4.07	4.36	4.40
Dry Natural Gas	19.16	21.26	22.37	22.46	23.63	26.16	26.63	29.59	31.70	31.99
Coal	23.12	25.43	20.35	20.54	26.47	16.33	13.58	27.21	13.47	11.69
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.06	7.32
Renewable Energy[1]	6.50	6.98	8.29	8.30	7.65	10.10	10.52	8.20	11.06	11.88
Other[2]	1.65	0.57	0.59	0.58	0.33	0.30	0.30	0.33	0.33	0.33
Total	**73.30**	**77.01**	**74.49**	**74.79**	**79.98**	**75.38**	**73.50**	**86.18**	**79.19**	**78.99**
Imports										
Crude Oil[3]	18.96	23.21	22.90	22.90	25.22	24.85	24.90	26.48	25.87	25.70
Petroleum Products[4]	4.14	4.85	4.68	4.68	6.46	6.44	6.44	10.77	11.02	11.01
Natural Gas	3.63	4.90	5.47	5.48	5.49	6.51	6.70	6.60	7.93	8.04
Other Imports[5]	0.64	1.11	1.02	1.02	0.96	0.88	0.88	0.96	0.82	0.82
Total	**27.37**	**34.08**	**34.07**	**34.07**	**38.12**	**38.68**	**38.93**	**44.82**	**45.63**	**45.57**
Exports										
Petroleum[6]	1.98	1.81	1.80	1.80	1.79	1.79	1.77	1.90	1.93	1.92
Natural Gas	0.17	0.33	0.12	0.12	0.43	0.12	0.12	0.63	0.12	0.12
Coal	1.48	1.51	1.51	1.51	1.45	1.51	1.43	1.41	1.44	1.44
Total	**3.62**	**3.64**	**3.43**	**3.43**	**3.67**	**3.42**	**3.32**	**3.94**	**3.49**	**3.48**
Discrepancy[7]	**0.95**	**0.39**	**-0.07**	**0.40**	**0.21**	**0.45**	**-0.25**	**-0.03**	**0.13**	**0.03**
Consumption										
Petroleum Products[8]	38.07	41.40	41.08	41.07	44.43	44.42	44.48	50.60	51.00	51.04
Natural Gas	21.90	25.78	27.64	27.75	28.52	32.30	32.99	35.40	39.33	39.72
Coal	21.46	24.37	19.68	19.38	25.54	14.95	12.95	26.48	12.37	10.68
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.06	7.32
Renewable Energy[1]	6.51	6.98	8.30	8.30	7.66	10.10	10.53	8.21	11.06	11.89
Other[9]	0.35	0.61	0.61	0.61	0.38	0.51	0.51	0.25	0.38	0.38
Total	**96.09**	**107.05**	**105.20**	**105.02**	**114.21**	**110.19**	**109.36**	**127.10**	**121.20**	**121.04**
Net Imports - Petroleum	**21.12**	**26.26**	**25.79**	**25.78**	**29.88**	**29.50**	**29.58**	**35.36**	**34.96**	**34.79**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	2.85	2.85	2.68	3.75	4.16	3.14	4.32	4.42
Coal Minemouth Price (dollars per ton)	17.23	14.76	13.70	13.70	13.69	11.86	12.03	12.84	10.87	11.16
Average Electric Price (cents per Kwh)	6.6	6.2	7.3	7.2	5.9	7.7	8.2	6.0	7.7	7.9

[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.89	0.89	0.81	0.81	0.81	0.75	0.76	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	0.46	0.46	0.41	0.42	0.42	0.39	0.41	0.41
Petroleum Subtotal	1.42	1.42	1.43	1.43	1.29	1.31	1.31	1.21	1.24	1.24
Natural Gas	4.85	5.46	5.40	5.40	5.69	5.50	5.42	6.30	6.05	6.00
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	0.43	0.43	0.43	0.43	0.42	0.42	0.44	0.42	0.42
Electricity	3.91	4.50	4.33	4.34	4.96	4.64	4.57	5.80	5.41	5.39
Delivered Energy	**10.62**	**11.86**	**11.63**	**11.65**	**12.42**	**11.92**	**11.78**	**13.80**	**13.17**	**13.10**
Electricity Related Losses	8.46	9.46	9.01	8.93	9.88	8.80	8.62	10.58	9.00	8.99
Total	**19.08**	**21.32**	**20.64**	**20.58**	**22.30**	**20.72**	**20.39**	**24.38**	**22.17**	**22.09**
Commercial										
Distillate Fuel	0.36	0.41	0.41	0.41	0.41	0.44	0.44	0.39	0.46	0.49
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.66	0.66	0.67	0.69	0.70	0.66	0.73	0.76
Natural Gas	3.15	3.71	3.66	3.66	3.89	3.70	3.63	4.12	3.97	3.95
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.18	4.20	4.89	4.59	4.54	5.61	5.22	5.19
Delivered Energy	**7.59**	**8.87**	**8.65**	**8.67**	**9.60**	**9.14**	**9.03**	**10.55**	**10.08**	**10.05**
Electricity Related Losses	8.00	9.15	8.69	8.64	9.74	8.71	8.56	10.23	8.68	8.66
Total	**15.59**	**18.02**	**17.34**	**17.31**	**19.34**	**17.85**	**17.59**	**20.79**	**18.76**	**18.71**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.12	1.12	1.27	1.27	1.28	1.44	1.46	1.46
Liquefied Petroleum Gas	2.32	2.45	2.45	2.44	2.50	2.58	2.63	2.83	3.10	3.10
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	0.22	0.22	0.22	0.22	0.25	0.37	0.38	0.27	0.41	0.41
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	4.49	4.49	4.49	4.76	4.79	4.84	5.25	5.40	5.45
Petroleum Subtotal	9.39	9.95	9.92	9.92	10.55	10.77	10.90	11.78	12.34	12.39
Natural Gas[6]	9.43	10.42	10.48	10.47	11.11	11.02	10.79	12.33	11.98	11.97
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.83	1.83	1.85	1.90	1.90	1.89	1.99	1.99
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.23
Coal Subtotal	2.54	2.62	2.63	2.63	2.61	2.66	2.66	2.62	2.71	2.72
Renewable Energy[7]	2.15	2.42	2.40	2.40	2.64	2.63	2.63	3.08	3.09	3.13
Electricity	3.63	3.90	3.81	3.81	4.19	3.98	3.97	4.81	4.40	4.35
Delivered Energy	**27.15**	**29.32**	**29.24**	**29.23**	**31.10**	**31.07**	**30.95**	**34.62**	**34.52**	**34.55**
Electricity Related Losses	7.85	8.22	7.93	7.84	8.34	7.56	7.48	8.78	7.32	7.26
Total	**35.00**	**37.53**	**37.17**	**37.07**	**39.45**	**38.64**	**38.43**	**43.40**	**41.84**	**41.82**

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Transportation										
Distillate Fuel	5.13	6.28	6.20	6.20	6.99	6.88	6.84	8.21	8.09	8.08
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	17.70	17.64	17.64	19.05	18.97	18.95	21.32	21.27	21.25
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	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	28.89	28.89	31.75	31.53	31.48	36.77	36.59	36.56
Pipeline Fuel Natural Gas	0.66	0.77	0.82	0.82	0.89	0.98	1.01	1.08	1.20	1.22
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	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**	**29.99**	**29.87**	**29.88**	**32.89**	**32.76**	**32.73**	**38.23**	**38.15**	**38.14**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.22	0.22	0.30	0.28	0.28
Total	**26.41**	**30.18**	**30.06**	**30.06**	**33.12**	**32.99**	**32.95**	**38.53**	**38.43**	**38.42**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.61	8.61	9.47	9.39	9.37	10.80	10.78	10.79
Kerosene	0.15	0.14	0.14	0.14	0.13	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	3.03	3.03	3.03	3.05	3.14	3.19	3.38	3.67	3.66
Motor Gasoline[2]	16.17	17.96	17.89	17.90	19.32	19.24	19.22	21.63	21.58	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	1.05	1.17	1.18	1.17	1.21	1.32	1.34	1.25	1.38	1.38
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.07	5.12	5.58	5.73	5.78
Petroleum Subtotal	36.95	41.08	40.89	40.89	44.26	44.31	44.38	50.42	50.90	50.95
Natural Gas[6]	18.11	20.42	20.41	20.40	21.67	21.30	20.94	24.00	23.34	23.29
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.95	1.95	1.98	2.03	2.03	2.02	2.12	2.12
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.23
Coal Subtotal	2.65	2.74	2.75	2.75	2.74	2.79	2.79	2.74	2.84	2.84
Renewable Energy[13]	2.65	2.95	2.94	2.94	3.19	3.17	3.17	3.65	3.64	3.68
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.41	12.45	14.15	13.32	13.20	16.39	15.19	15.09
Delivered Energy	**71.65**	**80.04**	**79.40**	**79.43**	**86.01**	**84.89**	**84.48**	**97.20**	**95.92**	**95.85**
Electricity Related Losses	24.44	27.02	25.81	25.59	28.20	25.30	24.88	29.89	25.28	25.19
Total	**96.09**	**107.05**	**105.20**	**105.02**	**114.21**	**110.19**	**109.36**	**127.10**	**121.20**	**121.04**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.03	0.03	0.04	0.03	0.02	0.04	0.02	0.02
Residual Fuel	1.07	0.27	0.15	0.15	0.13	0.09	0.08	0.14	0.08	0.08
Petroleum Subtotal	1.13	0.32	0.18	0.18	0.17	0.11	0.10	0.19	0.10	0.10
Natural Gas	3.79	5.36	7.23	7.35	6.84	11.00	12.04	11.40	15.99	16.44
Steam Coal	18.81	21.63	16.93	16.63	22.80	12.17	10.16	23.73	9.53	7.84
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.06	7.32
Renewable Energy[15]	3.86	4.03	5.36	5.37	4.47	6.93	7.36	4.56	7.42	8.21
Electricity Imports[16]	0.35	0.61	0.61	0.61	0.37	0.50	0.50	0.24	0.37	0.37
Total	**35.73**	**39.85**	**38.22**	**38.04**	**42.35**	**38.62**	**38.08**	**46.28**	**40.47**	**40.28**

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.64	8.64	9.51	9.42	9.40	10.84	10.79	10.81
Kerosene	0.15	0.14	0.14	0.14	0.13	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	3.03	3.03	3.03	3.05	3.14	3.19	3.38	3.67	3.66
Motor Gasoline[2]	16.17	17.96	17.89	17.90	19.32	19.24	19.22	21.63	21.58	21.56
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.52	1.52	1.70	1.69	1.69
Residual Fuel	2.12	1.44	1.33	1.32	1.34	1.41	1.42	1.39	1.46	1.46
Other Petroleum[12]	4.53	4.76	4.76	4.76	5.04	5.07	5.12	5.58	5.73	5.78
Petroleum Subtotal	38.07	41.40	41.08	41.07	44.43	44.42	44.48	50.60	51.00	51.04
Natural Gas	21.90	25.78	27.64	27.75	28.52	32.30	32.99	35.40	39.33	39.72
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.60	0.50	0.50	0.50
Steam Coal	20.65	23.57	18.88	18.58	24.77	14.19	12.19	25.75	11.64	9.96
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.15	0.15	0.22	0.22	0.23
Coal Subtotal	21.46	24.37	19.68	19.38	25.54	14.95	12.95	26.48	12.37	10.68
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.06	7.32
Renewable Energy[17]	6.51	6.98	8.30	8.30	7.66	10.10	10.53	8.21	11.07	11.89
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.50	0.50	0.24	0.37	0.37
Total	**96.09**	**107.05**	**105.20**	**105.02**	**114.21**	**110.19**	**109.36**	**127.10**	**121.20**	**121.04**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	79.40	79.43	86.01	84.89	84.48	97.20	95.92	95.85
Total Energy Use	96.09	107.05	105.20	105.02	114.21	110.19	109.36	127.10	121.20	121.04
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	10888	10888	12667	12618	12606	16515	16523	16523
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1589.8	1589.6	1816.2	1602.8	1553.8	2045.4	1747.7	1710.6

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[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E3. Energy Prices by Sector and Source
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Residential	**13.12**	**12.91**	**14.14**	**14.10**	**13.15**	**15.68**	**16.35**	**13.59**	**16.15**	**16.36**
Primary Energy[1]	6.72	7.12	7.35	7.34	7.00	7.78	8.07	7.02	7.96	8.06
Petroleum Products[2]	7.55	9.18	9.12	9.08	9.37	9.31	9.30	9.66	9.79	9.79
Distillate Fuel	6.27	7.34	7.33	7.33	7.51	7.47	7.46	7.99	8.01	8.02
Liquefied Petroleum Gas	10.36	12.83	12.62	12.48	13.06	12.92	12.91	12.90	13.20	13.19
Natural Gas	6.52	6.63	6.94	6.94	6.52	7.47	7.83	6.56	7.63	7.76
Electricity	23.46	21.84	24.91	24.79	21.88	27.37	28.63	22.16	27.25	27.59
Commercial	**13.20**	**12.36**	**14.34**	**14.28**	**11.74**	**15.22**	**16.11**	**12.37**	**15.52**	**15.81**
Primary Energy[1]	5.22	5.35	5.61	5.61	5.53	6.29	6.58	5.76	6.64	6.74
Petroleum Products[2]	5.00	6.01	5.97	5.96	6.17	6.09	6.07	6.52	6.48	6.46
Distillate Fuel	4.37	5.13	5.12	5.12	5.28	5.23	5.22	5.77	5.77	5.77
Residual Fuel	2.63	3.64	3.62	3.62	3.69	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.31	5.62	5.62	5.49	6.43	6.78	5.72	6.78	6.90
Electricity	21.43	19.51	23.50	23.35	17.61	23.91	25.35	18.09	23.65	24.18
Industrial[4]	**5.32**	**5.49**	**5.97**	**5.94**	**5.44**	**6.47**	**6.77**	**5.85**	**6.90**	**6.97**
Primary Energy	3.92	4.25	4.35	4.33	4.37	4.77	4.94	4.73	5.30	5.34
Petroleum Products[2]	5.55	5.95	5.87	5.82	6.05	6.02	6.03	6.28	6.44	6.43
Distillate Fuel	4.65	5.29	5.29	5.29	5.46	5.42	5.41	5.98	6.00	6.00
Liquefied Petroleum Gas	8.50	7.94	7.72	7.58	8.00	7.98	8.01	7.86	8.31	8.30
Residual Fuel	2.78	3.37	3.34	3.34	3.42	3.33	3.33	3.58	3.49	3.50
Natural Gas[5]	2.79	3.17	3.52	3.52	3.30	4.28	4.67	3.77	4.93	5.03
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.54	1.53	1.44	1.43	1.43
Steam Coal	1.43	1.34	1.29	1.29	1.29	1.18	1.15	1.21	1.05	1.04
Electricity	13.01	12.30	15.13	15.02	11.21	16.10	17.14	11.60	15.93	16.32
Transportation	**8.30**	**9.27**	**9.30**	**9.30**	**9.45**	**9.54**	**9.56**	**9.32**	**9.34**	**9.34**
Primary Energy	8.29	9.25	9.28	9.28	9.44	9.52	9.53	9.30	9.32	9.31
Petroleum Products[2]	8.28	9.25	9.28	9.28	9.44	9.51	9.52	9.30	9.31	9.31
Distillate Fuel[6]	8.22	8.89	8.90	8.90	8.94	8.93	8.92	9.02	9.06	9.07
Jet Fuel[7]	4.70	5.24	5.22	5.23	5.46	5.46	5.46	5.88	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.68	10.69	10.92	11.05	11.07	10.68	10.68	10.67
Residual Fuel	2.46	3.10	3.10	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.04	13.93	14.24	14.22	14.23	13.88	14.21	14.20
Natural Gas[10]	7.02	6.80	7.12	7.12	7.03	8.01	8.36	7.33	8.36	8.45
Ethanol (E85)[11]	14.42	19.12	19.14	19.14	19.00	19.17	19.24	19.36	19.50	19.52
Methanol (M85)[12]	10.38	13.11	13.05	13.05	13.74	13.85	14.25	14.43	14.42	14.42
Electricity	15.58	14.29	15.77	15.70	13.53	16.06	16.51	13.03	14.94	14.98
Average End-Use Energy	**8.53**	**8.90**	**9.48**	**9.46**	**8.94**	**10.05**	**10.34**	**9.17**	**10.21**	**10.29**
Primary Energy	6.33	7.00	7.09	7.08	7.18	7.48	7.60	7.31	7.65	7.68
Electricity	19.40	18.10	21.36	21.25	17.18	22.71	23.94	17.57	22.60	23.03
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	1.69	1.70	1.52	2.42	2.83	1.85	3.32	3.58
Petroleum Products	2.50	3.70	3.83	3.84	4.06	4.24	4.29	4.33	4.57	4.60
Distillate Fuel	4.04	4.65	4.68	4.69	4.85	4.83	4.81	5.30	5.26	5.26
Residual Fuel	2.41	3.52	3.66	3.67	3.85	4.07	4.14	4.04	4.44	4.46
Natural Gas	2.54	2.89	3.23	3.24	3.02	4.07	4.48	3.61	4.81	4.92
Steam Coal	1.22	1.13	1.00	1.00	1.05	0.91	0.87	0.98	0.80	0.77

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.44	8.43	8.63	8.67	8.67	8.62	8.66	8.65
Distillate Fuel	7.27	8.07	8.07	8.08	8.18	8.15	8.14	8.41	8.42	8.42
Jet Fuel	4.70	5.24	5.22	5.23	5.46	5.46	5.46	5.88	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.63	8.49	8.87	8.82	8.84	8.64	9.04	9.02
Motor Gasoline[8]	9.45	10.64	10.68	10.68	10.92	11.05	11.07	10.68	10.68	10.67
Residual Fuel	2.48	3.26	3.25	3.24	3.33	3.31	3.31	3.49	3.48	3.48
Natural Gas	4.05	4.25	4.48	4.47	4.27	5.08	5.42	4.52	5.55	5.65
Coal	1.24	1.15	1.03	1.03	1.07	0.95	0.92	1.00	0.84	0.83
Ethanol (E85)[11]	14.42	19.12	19.14	19.14	19.00	19.17	19.24	19.36	19.50	19.52
Methanol (M85)[12]	10.38	13.11	13.05	13.05	13.74	13.85	14.25	14.43	14.42	14.42
Electricity	19.40	18.10	21.36	21.25	17.18	22.71	23.94	17.57	22.60	23.03
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	158.44	158.17	157.75	180.21	185.56	181.60	205.85	207.40
Commercial	99.10	108.63	122.81	122.69	111.63	137.79	144.07	129.48	155.18	157.62
Industrial	110.62	121.27	132.61	131.82	126.35	151.37	158.01	151.05	178.67	180.56
Transportation	212.64	270.40	269.78	269.89	301.90	302.62	302.53	345.30	344.36	344.02
Total Non-Renewable Expenditures	556.41	647.83	683.63	682.56	697.64	771.98	790.16	807.43	884.07	889.61
Transportation Renewable Expenditures	0.14	0.42	0.41	0.41	0.61	0.61	0.62	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**684.05**	**682.98**	**698.25**	**772.59**	**790.78**	**808.29**	**884.93**	**890.46**

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[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	1671	1643	2232	1210	1016	2317	947	784
Petroleum	104	32	19	19	18	12	11	19	11	11
Natural Gas[2]	365	574	804	843	867	1475	1623	1568	2296	2349
Nuclear Power	730	740	740	740	720	741	741	577	661	686
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	443	443	384	509	518	390	554	604
Total	**3386**	**3811**	**3677**	**3687**	**4220**	**3946**	**3907**	**4872**	**4468**	**4433**
Non-Utility Generation for Own Use	16	16	22	22	16	21	21	16	20	20
Distributed Generation	0	1	0	0	3	0	0	6	0	0
Cogenerators[4]										
Coal	47	52	52	52	52	51	51	52	51	50
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	256	255	256	314	312	298	450	467
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	49
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**363**	**363**	**369**	**427**	**424**	**421**	**572**	**590**
Other End-Use Generators[7]	5	5	5	5	5	5	5	5	5	5
Sales to Utilities	150	171	176	176	176	189	185	200	232	235
Generation for Own Use	156	180	192	192	198	243	243	226	346	359
Net Imports[8]	**33**	**57**	**57**	**57**	**35**	**47**	**47**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1146	1317	1270	1273	1452	1359	1340	1699	1586	1579
Commercial	1083	1275	1225	1231	1432	1344	1331	1644	1530	1520
Industrial	1063	1144	1117	1118	1227	1167	1163	1411	1289	1275
Transportation	17	26	26	26	35	34	34	49	49	48
Total	**3309**	**3762**	**3638**	**3648**	**4146**	**3905**	**3868**	**4803**	**4453**	**4422**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	8.5	8.5	7.5	9.3	9.8	7.6	9.3	9.4
Commercial	7.3	6.7	8.0	8.0	6.0	8.2	8.6	6.2	8.1	8.2
Industrial	4.4	4.2	5.2	5.1	3.8	5.5	5.8	4.0	5.4	5.6
Transportation	5.3	4.9	5.4	5.4	4.6	5.5	5.6	4.4	5.1	5.1
All Sectors Average	**6.6**	**6.2**	**7.3**	**7.2**	**5.9**	**7.7**	**8.2**	**6.0**	**7.7**	**7.9**
Prices by Service Category[9] (1999 cents per kwh)										
Generation	4.1	3.6	4.7	4.6	3.2	5.0	5.4	3.4	5.0	5.2
Transmission	0.6	0.6	0.7	0.7	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	13.82	10.39	8.23	8.24	9.70	4.52	4.02	8.95	3.27	3.27
Nitrogen Oxide	5.46	4.22	2.79	2.74	4.20	1.42	1.32	4.37	1.22	1.16

[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	299.2	299.5	317.4	271.8	265.3	317.8	239.1	217.4
Other Fossil Steam[3]	138.2	129.6	125.5	125.6	121.1	115.1	115.3	117.2	97.6	94.3
Combined Cycle	20.2	49.4	69.6	71.1	124.0	170.0	198.6	230.0	280.9	288.5
Combustion Turbine/Diesel	75.6	129.7	112.2	113.9	162.1	120.7	120.3	207.7	183.0	193.9
Nuclear Power	97.4	97.5	97.5	97.5	94.2	96.9	96.9	71.6	84.1	88.4
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]	88.1	91.5	96.3	96.5	94.8	104.0	106.9	96.3	117.9	130.0
Distributed Generation[5]	0.0	2.0	2.0	2.4	6.1	3.6	3.9	14.0	6.7	6.9
Total	**745.0**	**821.5**	**821.7**	**826.0**	**939.4**	**901.6**	**926.8**	**1074.3**	**1029.1**	**1039.2**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	0.0	0.0	20.1	0.0	0.0	21.5	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	20.8	41.0	42.5	95.7	141.7	170.3	201.6	252.5	261.3
Combustion Turbine/Diesel	0.0	57.0	41.1	42.8	90.8	51.6	51.0	137.2	115.4	127.6
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	0.6	5.5	5.6	1.9	11.1	14.1	2.4	24.0	36.1
Distributed Generation[5]	0.0	2.0	2.0	2.4	6.1	3.6	3.9	14.0	6.7	6.9
Total	**0.0**	**82.9**	**89.5**	**93.3**	**214.6**	**208.0**	**239.2**	**376.7**	**398.6**	**432.0**
Cumulative Total Additions	**0.0**	**94.5**	**101.0**	**104.9**	**228.1**	**221.5**	**252.8**	**391.4**	**413.4**	**446.8**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	7.4	7.0	9.2	35.3	41.7	10.2	67.9	89.6
Other Fossil Steam[3]	0.0	8.5	12.5	12.5	17.0	23.0	22.8	20.9	40.5	43.8
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	1.4
Combustion Turbine/Diesel	0.0	3.8	4.6	4.6	5.1	6.7	6.4	5.9	8.2	9.5
Nuclear Power	0.0	0.0	0.0	0.0	3.3	0.6	0.6	25.9	13.4	9.1
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**	**19.0**	**24.7**	**24.2**	**34.9**	**66.0**	**72.0**	**63.4**	**130.4**	**153.6**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	41.8	41.7	42.9	50.1	50.2	48.8	69.7	72.1
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	1.1
Renewable Sources[4]	5.3	5.9	5.8	5.8	6.8	6.7	6.7	8.2	8.3	8.4
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	**51.6**	**59.2**	**60.9**	**60.9**	**63.1**	**70.3**	**70.4**	**70.7**	**91.7**	**94.2**
Cumulative Additions[6]	**0.0**	**7.5**	**9.3**	**9.2**	**11.4**	**18.7**	**18.8**	**19.0**	**40.0**	**42.6**

Table E5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 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 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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 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	147.8	202.8	103.4	95.6	183.2	81.8	92.6	206.7	149.6	155.6
Gross Domestic Trade	**330.0**	**328.1**	**228.7**	**220.9**	**286.1**	**184.7**	**195.5**	**206.7**	**149.6**	**155.6**
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)	4292.5	6044.9	4015.4	3686.4	4987.6	3534.1	4257.2	6227.5	6527.5	6898.6
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.**	**9921.2**	**9592.2**	**9838.8**	**8385.3**	**9108.4**	**6227.5**	**6527.5**	**6898.6**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	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**

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[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Production										
Dry Gas Production[1]	18.67	20.72	21.80	21.89	23.03	25.49	25.95	28.84	30.90	31.18
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**	**4.47**	**5.23**	**5.23**	**4.94**	**6.25**	**6.43**	**5.83**	**7.64**	**7.74**
Canada	3.29	4.28	4.49	4.49	4.68	5.19	5.37	5.46	6.06	6.17
Mexico	-0.01	-0.18	0.30	0.30	-0.25	0.32	0.32	-0.40	0.36	0.36
Liquefied Natural Gas	0.10	0.37	0.44	0.44	0.51	0.73	0.74	0.77	1.22	1.22
Total Supply	**22.15**	**25.30**	**27.14**	**27.24**	**28.03**	**31.79**	**32.44**	**34.72**	**38.59**	**38.98**
Consumption by Sector										
Residential	4.72	5.32	5.25	5.26	5.54	5.35	5.28	6.14	5.89	5.84
Commercial	3.07	3.62	3.56	3.56	3.78	3.61	3.53	4.02	3.87	3.85
Industrial[3]	7.95	8.80	8.81	8.79	9.33	9.12	8.88	10.17	9.73	9.71
Electric Generators[4]	3.72	5.26	7.10	7.21	6.72	10.80	11.82	11.19	15.69	16.13
Lease and Plant Fuel[5]	1.23	1.35	1.40	1.40	1.49	1.61	1.63	1.83	1.93	1.95
Pipeline Fuel	0.64	0.75	0.80	0.80	0.87	0.96	0.98	1.06	1.17	1.19
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.14	0.14
Total	**21.35**	**25.14**	**26.97**	**27.08**	**27.82**	**31.53**	**32.22**	**34.55**	**38.42**	**38.81**
Discrepancy[7]	**0.80**	**0.16**	**0.17**	**0.16**	**0.21**	**0.26**	**0.22**	**0.17**	**0.17**	**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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A. 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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	2.85	2.85	2.68	3.75	4.16	3.14	4.32	4.42
Average Import Price	2.29	2.48	2.65	2.64	2.41	2.76	2.88	2.67	3.23	3.29
Average[2]	**2.11**	**2.49**	**2.81**	**2.81**	**2.63**	**3.55**	**3.90**	**3.05**	**4.10**	**4.19**
Delivered Prices										
Residential	6.69	6.81	7.13	7.13	6.70	7.67	8.04	6.74	7.84	7.97
Commercial	5.49	5.45	5.77	5.77	5.64	6.60	6.96	5.87	6.96	7.09
Industrial[3]	2.87	3.26	3.61	3.61	3.39	4.40	4.79	3.87	5.06	5.16
Electric Generators[4]	2.59	2.94	3.30	3.30	3.08	4.15	4.56	3.68	4.91	5.01
Transportation[5]	7.21	6.99	7.31	7.31	7.22	8.23	8.58	7.53	8.58	8.68
Average[6]	**4.16**	**4.36**	**4.59**	**4.59**	**4.38**	**5.21**	**5.56**	**4.64**	**5.69**	**5.79**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.32	4.31	4.07	4.12	4.15	3.69	3.74	3.78
Commercial	3.37	2.96	2.96	2.96	3.01	3.05	3.07	2.82	2.86	2.90
Industrial[3]	0.75	0.76	0.80	0.80	0.76	0.85	0.89	0.82	0.95	0.97
Electric Generators[4]	0.48	0.45	0.48	0.49	0.45	0.60	0.66	0.63	0.80	0.82
Transportation[5]	5.10	4.49	4.50	4.50	4.59	4.67	4.69	4.48	4.48	4.48
Average[6]	**2.05**	**1.87**	**1.78**	**1.78**	**1.75**	**1.65**	**1.66**	**1.59**	**1.59**	**1.60**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.67	22.69	22.55	22.06	21.89	22.62	21.99	22.09
Commercial	10.36	10.71	10.54	10.55	11.40	10.99	10.83	11.32	11.06	11.14
Industrial[3]	6.00	6.72	7.02	7.01	7.10	7.71	7.94	8.34	9.29	9.43
Electric Generators[4]	1.77	2.35	3.43	3.55	3.03	6.46	7.84	7.00	12.58	13.23
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.41	0.41	0.69	0.65	0.64
Total	**39.82**	**42.98**	**43.90**	**44.04**	**44.49**	**47.63**	**48.91**	**49.97**	**55.57**	**56.53**

[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.43**	**20.43**	**20.81**	**20.84**	**20.77**	**21.46**	**21.47**	**21.47**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.58**	**5.58**	**5.15**	**5.16**	**5.12**	**5.01**	**5.29**	**5.37**
Lower 48 Onshore	3.27	2.75	2.76	2.76	2.49	2.53	2.53	2.63	2.73	2.76
Conventional	2.59	2.15	2.16	2.16	1.82	1.90	1.90	1.91	2.07	2.11
Enhanced Oil Recovery	0.68	0.61	0.60	0.61	0.66	0.63	0.63	0.72	0.66	0.65
Lower 48 Offshore	1.56	2.05	2.03	2.03	2.02	1.99	1.95	1.75	1.92	1.97
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.46**	**15.46**	**14.03**	**14.22**	**14.13**	**13.43**	**14.23**	**14.41**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**2.85**	**2.85**	**2.68**	**3.75**	**4.16**	**3.14**	**4.32**	**4.42**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**21.80**	**21.89**	**23.03**	**25.49**	**25.95**	**28.84**	**30.90**	**31.18**
Lower 48 Onshore	12.83	14.33	15.09	15.16	16.32	18.56	18.89	21.20	22.80	22.90
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.38	1.37	1.35	1.41	1.42
Non-Associated	11.03	12.82	13.58	13.64	14.98	17.18	17.51	19.85	21.40	21.47
Conventional	6.64	7.19	7.76	7.80	8.31	9.46	9.71	11.38	11.22	11.02
Unconventional	4.39	5.62	5.82	5.85	6.66	7.72	7.80	8.48	10.17	10.45
Lower 48 Offshore	5.43	5.93	6.24	6.27	6.21	6.43	6.56	7.07	7.53	7.72
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.05	1.05	1.01	1.04	1.05
Non-Associated	4.50	4.85	5.17	5.20	5.13	5.38	5.52	6.06	6.49	6.67
Alaska	0.42	0.47	0.46	0.46	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**166.23**	**168.33**	**168.01**	**174.58**	**184.36**	**182.87**	**188.20**	**212.04**	**219.65**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.11**	**0.11**	**0.11**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.94**	**24.11**	**27.70**	**27.65**	**28.67**	**36.69**	**38.39**	**39.25**	**51.62**	**52.60.5**

[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Production[1]										
Appalachia	434	422	344	348	412	269	242	395	215	204
Interior	185	180	130	131	177	84	73	163	75	65
West	485	633	514	519	708	446	340	784	371	297
East of the Mississippi	561	554	430	434	545	325	292	525	267	249
West of the Mississippi	543	681	558	564	752	474	363	817	393	316
Total	**1105**	**1235**	**988**	**998**	**1297**	**799**	**655**	**1342**	**660**	**565**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	60	57	56	58	58
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-51**	**-48**	**-36**	**-49**	**-49**
Total Supply[2]	**1055**	**1191**	**940**	**950**	**1256**	**748**	**607**	**1306**	**611**	**516**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	84	84	84	87	87	86	91	91
Coke Plants	28	26	26	26	23	23	23	19	19	18
Electric Generators[4]	922	1078	850	835	1145	623	516	1198	493	402
Total	**1034**	**1192**	**965**	**950**	**1257**	**738**	**631**	**1308**	**608**	**517**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**-24**	**0**	**-1**	**10**	**-23**	**-2**	**3**	**-1**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	13.70	13.70	13.69	11.86	12.03	12.84	10.87	11.16
(1999 dollars per million Btu)	0.82	0.72	0.67	0.67	0.67	0.58	0.58	0.63	0.53	0.54
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	28.25	28.26	28.41	25.79	25.21	26.55	23.00	22.68
Coke Plants	44.20	42.47	42.58	42.68	41.29	41.25	40.95	38.57	38.42	38.41
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	19.91	19.86	20.84	17.73	17.13	19.40	15.40	14.99
(1999 dollars per million Btu)	1.22	1.13	1.00	1.00	1.05	0.91	0.87	0.98	0.80	0.77
Average	**25.82**	**23.53**	**21.24**	**21.23**	**21.72**	**19.42**	**19.12**	**20.15**	**17.26**	**17.21**
Exports[7]	37.43	36.32	36.00	36.06	35.54	34.29	33.38	33.13	31.23	31.03

[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	79.92	79.92	78.74	80.04	80.04	78.74	80.04	80.05
Geothermal[2]	2.87	3.16	5.61	5.60	4.31	10.80	12.86	4.34	10.95	12.86
Municipal Solid Waste[3]	2.59	3.15	3.76	3.92	3.56	4.18	4.37	4.07	4.84	4.90
Wood and Other Biomass[4]	1.52	1.68	2.03	2.03	2.04	2.40	2.56	2.37	5.60	8.78
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.54	4.58	5.51	5.97	6.47	5.78	15.50	22.43
Total	**88.07**	**91.47**	**96.31**	**96.48**	**94.76**	**103.99**	**106.90**	**96.33**	**117.95**	**130.03**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	303.50	303.50	298.99	303.41	303.40	297.94	302.33	302.34
Geothermal[2]	13.07	15.90	44.80	44.71	24.98	85.65	101.91	25.33	86.89	101.96
Municipal Solid Waste[3]	18.05	22.30	27.07	28.29	24.94	29.84	31.30	28.85	34.88	35.36
Wood and Other Biomass[4]	8.86	14.45	56.87	55.89	21.55	74.65	64.24	22.15	83.38	96.45
Dedicated Plants	7.56	8.67	11.09	11.06	10.88	13.30	14.37	13.35	34.90	56.14
Cofiring	1.30	5.78	45.78	44.83	10.67	61.35	49.87	8.80	48.48	40.30
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	4.46	9.42	9.73	9.84	12.33	13.61	15.07	13.10	44.24	64.99
Total	**352.79**	**362.28**	**443.12**	**443.39**	**384.41**	**508.78**	**517.54**	**390.09**	**554.45**	**603.82**
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	5.13	5.13	6.06	6.05	6.04	7.54	7.59	7.72
Total	**5.35**	**5.87**	**5.83**	**5.83**	**6.76**	**6.74**	**6.74**	**8.23**	**8.28**	**8.42**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.69	29.69	35.01	34.86	34.82	43.52	43.78	44.58
Total	**31.10**	**33.95**	**33.71**	**33.71**	**39.03**	**38.88**	**38.85**	**47.55**	**47.80**	**48.61**
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	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	0.76
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.

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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.42**	**0.42**	**0.44**	**0.42**	**0.42**
Wood	0.41	0.43	0.43	0.43	0.43	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**	**2.40**	**2.40**	**2.64**	**2.63**	**2.63**	**3.08**	**3.09**	**3.13**
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	2.45	2.45	2.90	2.90	2.94
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.21	0.21
Electric Generators[5]	**3.86**	**4.03**	**5.36**	**5.37**	**4.47**	**6.93**	**7.36**	**4.56**	**7.42**	**8.21**
Conventional Hydroelectric	3.17	3.08	3.12	3.12	3.08	3.12	3.12	3.06	3.11	3.11
Geothermal	0.27	0.37	1.15	1.15	0.66	2.46	2.96	0.67	2.50	2.96
Municipal Solid Waste[6]	0.25	0.30	0.37	0.39	0.34	0.41	0.43	0.39	0.47	0.48
Biomass	0.12	0.18	0.60	0.59	0.26	0.79	0.68	0.27	0.86	0.97
Dedicated Plants	0.10	0.11	0.12	0.12	0.13	0.14	0.15	0.16	0.36	0.56
Cofiring	0.02	0.07	0.49	0.48	0.13	0.65	0.53	0.11	0.50	0.40
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	0.10	0.10	0.10	0.13	0.14	0.15	0.13	0.45	0.67
Total Marketed Renewable Energy	**6.61**	**7.16**	**8.47**	**8.48**	**7.84**	**10.28**	**10.71**	**8.40**	**11.26**	**12.09**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**

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[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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

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	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Residential										
Petroleum	26.0	26.8	27.0	27.0	24.4	24.7	24.7	22.9	23.4	23.4
Natural Gas	69.5	78.6	77.7	77.8	82.0	79.2	78.1	90.8	87.1	86.4
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	192.6	223.2	187.0	187.0	240.4	165.6	149.1	274.7	169.9	157.0
Total	**289.3**	**330.0**	**293.0**	**293.0**	**348.1**	**270.8**	**253.1**	**389.6**	**281.6**	**268.1**
Commercial										
Petroleum	13.7	12.9	12.9	12.9	13.1	13.6	13.7	12.9	14.3	14.8
Natural Gas	45.4	53.5	52.7	52.7	56.0	53.3	52.3	59.4	57.2	56.9
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	180.5	180.8	237.0	163.8	148.1	265.8	163.9	151.2
Total	**242.9**	**284.1**	**247.8**	**248.2**	**307.9**	**232.6**	**215.9**	**340.0**	**237.3**	**224.9**
Industrial[1]										
Petroleum	104.2	99.0	99.0	99.0	104.7	108.1	111.7	115.6	125.9	126.8
Natural Gas[2]	141.6	147.8	148.6	148.5	157.6	157.3	153.1	174.9	169.8	169.7
Coal	55.9	66.5	66.7	66.7	66.3	67.5	67.5	66.4	68.8	68.9
Electricity	178.8	193.9	164.6	164.2	203.0	142.3	129.4	228.1	138.1	126.9
Total	**480.4**	**507.2**	**479.0**	**478.3**	**531.6**	**475.2**	**461.6**	**584.9**	**502.6**	**492.2**
Transportation										
Petroleum[3]	485.8	556.8	553.5	553.6	608.6	604.5	603.3	705.1	701.4	700.8
Natural Gas[4]	9.5	11.8	12.6	12.6	14.1	15.5	15.8	17.9	19.4	19.7
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	3.8	3.8	5.7	4.2	3.8	7.9	5.2	4.8
Total[3]	**498.2**	**573.1**	**570.0**	**570.1**	**628.6**	**624.2**	**623.1**	**730.9**	**726.1**	**725.4**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	692.4	692.4	750.8	750.8	753.4	856.4	865.0	865.9
Natural Gas	266.0	291.8	291.6	291.6	309.7	305.2	299.2	342.9	333.5	332.7
Coal	58.8	69.6	69.7	69.7	69.5	70.7	70.7	69.6	72.0	72.1
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	637.5	535.9	535.8	686.1	475.9	430.4	776.5	477.1	439.9
Total[3]	**1510.8**	**1694.3**	**1589.8**	**1589.6**	**1816.2**	**1602.8**	**1553.8**	**2045.4**	**1747.7**	**1710.6**
Electric Generators[6]										
Petroleum	20.0	6.8	3.9	3.7	3.5	2.3	2.1	3.9	2.0	2.0
Natural Gas	45.8	77.1	104.2	105.8	98.6	158.4	173.4	164.1	230.3	236.7
Coal	490.5	553.6	427.9	426.2	584.0	315.1	254.8	608.4	244.8	201.2
Total	**556.3**	**637.5**	**535.9**	**535.8**	**686.1**	**475.9**	**430.4**	**776.5**	**477.1**	**439.9**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	696.3	696.2	754.3	753.2	755.6	860.3	867.0	867.9
Natural Gas	311.8	368.9	395.7	397.4	408.2	463.6	472.7	507.1	563.7	569.4
Coal	549.3	623.1	497.7	495.9	653.5	385.9	325.5	678.0	316.8	273.3
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**	**1694.3**	**1589.8**	**1589.6**	**1816.2**	**1602.8**	**1553.8**	**2045.4**	**1747.7**	**1710.6**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.5**	**5.5**	**6.1**	**5.3**	**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.

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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Table E14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008	Reference	Integrated 2008	Integrated -7 2008
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	12.01	11.65	10.76	12.01	11.65	15.24	19.91	17.65
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**60.64**	**73.94**	**169.55**	**213.14**	**141.12**	**246.09**	**164.91**	**95.11**
NO_x Controls (gigawatts)										
Combustion	0.00	65.84	109.98	109.45	66.93	112.45	110.83	67.57	112.45	110.83
SCR Post-combustion	0.00	84.31	55.86	56.32	85.97	123.37	107.53	89.75	123.37	107.53
SNCR Post-combustion	0.00	25.36	1.72	4.01	28.78	47.56	38.31	38.69	47.56	38.31
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	498.19	501.28	656.33	446.35	332.32	730.01	358.87	283.21
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	349.70	353.58	453.06	255.41	234.99	438.05	206.58	201.64
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	140.41	143.28	187.25	97.17	87.88	174.20	94.60	80.11

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.
SO_2 = Sulfur 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 MCBASE.D121300A, FDPOL08.D121500A, and FDP7B08.D121500A.

Appendix F

Tables for SO_2 Sensitivity Case

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Production							
Crude Oil and Lease Condensate	12.45	11.85	11.85	10.90	10.88	10.61	10.66
Natural Gas Plant Liquids	2.62	3.02	3.00	3.31	3.34	4.07	4.10
Dry Natural Gas	19.16	21.26	21.16	23.63	23.82	29.59	29.77
Coal	23.12	25.43	25.36	26.47	26.14	27.21	26.96
Nuclear Power	7.79	7.90	7.90	7.69	7.69	6.17	6.13
Renewable Energy[1]	6.50	6.98	7.01	7.65	7.59	8.20	8.15
Other[2]	1.65	0.57	0.57	0.33	0.33	0.33	0.33
Total	**73.30**	**77.01**	**76.85**	**79.98**	**79.78**	**86.18**	**86.09**
Imports							
Crude Oil[3]	18.96	23.21	23.20	25.22	25.18	26.48	26.44
Petroleum Products[4]	4.14	4.85	4.84	6.46	6.46	10.77	10.72
Natural Gas	3.63	4.90	4.95	5.49	5.57	6.60	6.69
Other Imports[5]	0.64	1.11	1.11	0.96	0.96	0.96	0.96
Total	**27.37**	**34.08**	**34.11**	**38.12**	**38.17**	**44.82**	**44.80**
Exports							
Petroleum[6]	1.98	1.81	1.81	1.79	1.78	1.90	1.89
Natural Gas	0.17	0.33	0.33	0.43	0.43	0.63	0.63
Coal	1.48	1.51	1.52	1.45	1.49	1.41	1.42
Total	**3.62**	**3.64**	**3.65**	**3.67**	**3.70**	**3.94**	**3.94**
Discrepancy[7]	**0.95**	**0.39**	**0.39**	**0.21**	**0.22**	**-0.03**	**-0.05**
Consumption							
Petroleum Products[8]	38.07	41.40	41.37	44.43	44.41	50.60	50.59
Natural Gas	21.90	25.78	25.73	28.52	28.78	35.40	35.66
Coal	21.46	24.37	24.29	25.54	25.17	26.48	26.21
Nuclear Power	7.79	7.90	7.90	7.69	7.69	6.17	6.13
Renewable Energy[1]	6.51	6.98	7.01	7.66	7.60	8.21	8.16
Other[9]	0.35	0.61	0.61	0.38	0.38	0.25	0.25
Total	**96.09**	**107.05**	**106.91**	**114.21**	**114.03**	**127.10**	**127.00**
Net Imports - Petroleum	**21.12**	**26.26**	**26.24**	**29.88**	**29.86**	**35.36**	**35.27**
Prices (1999 dollars per unit)							
World Oil Price (dollars per barrel)[10]	17.35	20.83	20.83	21.37	21.37	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.49	2.48	2.68	2.72	3.14	3.17
Coal Minemouth Price (dollars per ton)	17.23	14.76	13.53	13.69	12.59	12.84	12.25
Average Electric Price (cents per Kwh)	6.6	6.2	6.2	5.9	5.9	6.0	6.0

[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.

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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Energy Consumption							
Residential							
Distillate Fuel	0.86	0.88	0.88	0.81	0.81	0.75	0.75
Kerosene	0.10	0.08	0.08	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.45	0.45	0.41	0.41	0.39	0.39
Petroleum Subtotal	1.42	1.42	1.42	1.29	1.29	1.21	1.21
Natural Gas	4.85	5.46	5.46	5.69	5.69	6.30	6.30
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.43	0.43	0.43	0.43	0.44	0.44
Electricity	3.91	4.50	4.49	4.96	4.95	5.80	5.79
Delivered Energy	**10.62**	**11.86**	**11.86**	**12.42**	**12.41**	**13.80**	**13.79**
Electricity Related Losses	8.46	9.46	9.41	9.88	9.83	10.58	10.55
Total	**19.08**	**21.32**	**21.27**	**22.30**	**22.24**	**24.38**	**24.33**
Commercial							
Distillate Fuel	0.36	0.41	0.41	0.41	0.41	0.39	0.39
Residual Fuel	0.10	0.10	0.10	0.11	0.11	0.11	0.11
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	0.59	0.66	0.66	0.67	0.67	0.66	0.66
Natural Gas	3.15	3.71	3.72	3.89	3.88	4.12	4.12
Coal	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
Electricity	3.70	4.35	4.34	4.89	4.88	5.61	5.60
Delivered Energy	**7.59**	**8.87**	**8.87**	**9.60**	**9.58**	**10.55**	**10.53**
Electricity Related Losses	8.00	9.15	9.10	9.74	9.69	10.23	10.20
Total	**15.59**	**18.02**	**17.97**	**19.34**	**19.26**	**20.79**	**20.74**
Industrial[4]							
Distillate Fuel	1.07	1.13	1.13	1.27	1.27	1.44	1.45
Liquefied Petroleum Gas	2.32	2.45	2.45	2.50	2.50	2.83	2.84
Petrochemical Feedstock	1.29	1.42	1.42	1.53	1.53	1.70	1.70
Residual Fuel	0.22	0.22	0.22	0.25	0.25	0.27	0.27
Motor Gasoline[2]	0.21	0.23	0.23	0.25	0.25	0.28	0.28
Other Petroleum[5]	4.29	4.49	4.49	4.76	4.76	5.25	5.24
Petroleum Subtotal	9.39	9.95	9.94	10.55	10.55	11.78	11.78
Natural Gas[6]	9.43	10.42	10.43	11.11	11.12	12.33	12.34
Metallurgical Coal	0.75	0.69	0.69	0.61	0.61	0.50	0.50
Steam Coal	1.73	1.82	1.82	1.85	1.85	1.89	1.90
Net Coal Coke Imports	0.06	0.12	0.12	0.16	0.16	0.22	0.22
Coal Subtotal	2.54	2.62	2.63	2.61	2.62	2.62	2.62
Renewable Energy[7]	2.15	2.42	2.42	2.64	2.64	3.08	3.08
Electricity	3.63	3.90	3.90	4.19	4.18	4.81	4.81
Delivered Energy	**27.15**	**29.32**	**29.32**	**31.10**	**31.11**	**34.62**	**34.63**
Electricity Related Losses	7.85	8.22	8.17	8.34	8.30	8.78	8.77
Total	**35.00**	**37.53**	**37.49**	**39.45**	**39.41**	**43.40**	**43.40**

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Transportation							
Distillate Fuel	5.13	6.28	6.28	6.99	6.99	8.21	8.21
Jet Fuel[8]	3.46	3.90	3.90	4.51	4.51	5.97	5.97
Motor Gasoline[2]	15.92	17.70	17.70	19.05	19.04	21.32	21.32
Residual Fuel	0.74	0.85	0.85	0.85	0.85	0.87	0.87
Liquefied Petroleum Gas	0.02	0.03	0.03	0.04	0.04	0.06	0.06
Other Petroleum[9]	0.26	0.29	0.29	0.31	0.31	0.35	0.35
Petroleum Subtotal	25.54	29.06	29.06	31.75	31.75	36.77	36.77
Pipeline Fuel Natural Gas	0.66	0.77	0.76	0.89	0.89	1.08	1.09
Compressed Natural Gas	0.02	0.06	0.06	0.09	0.09	0.16	0.16
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	0.00	0.00	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**	**29.99**	**30.00**	**32.89**	**32.89**	**38.23**	**38.23**
Electricity Related Losses	0.13	0.19	0.19	0.24	0.23	0.30	0.30
Total	**26.41**	**30.18**	**30.18**	**33.12**	**33.12**	**38.53**	**38.53**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.42	8.70	8.70	9.47	9.47	10.80	10.80
Kerosene	0.15	0.14	0.14	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.90	4.51	4.51	5.97	5.97
Liquefied Petroleum Gas	2.88	3.03	3.02	3.05	3.05	3.38	3.39
Motor Gasoline[2]	16.17	17.96	17.96	19.32	19.31	21.63	21.63
Petrochemical Feedstock	1.29	1.42	1.42	1.53	1.53	1.70	1.70
Residual Fuel	1.05	1.17	1.17	1.21	1.21	1.25	1.25
Other Petroleum[12]	4.53	4.76	4.76	5.04	5.04	5.58	5.57
Petroleum Subtotal	36.95	41.08	41.08	44.26	44.25	50.42	50.41
Natural Gas[6]	18.11	20.42	20.43	21.67	21.67	24.00	24.00
Metallurgical Coal	0.75	0.69	0.69	0.61	0.61	0.50	0.50
Steam Coal	1.84	1.94	1.94	1.98	1.98	2.02	2.02
Net Coal Coke Imports	0.06	0.12	0.12	0.16	0.16	0.22	0.22
Coal Subtotal	2.65	2.74	2.74	2.74	2.74	2.74	2.75
Renewable Energy[13]	2.65	2.95	2.95	3.19	3.19	3.65	3.65
Methanol (M85)[11]	0.00	0.00	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
Electricity	11.29	12.84	12.83	14.15	14.12	16.39	16.36
Delivered Energy	**71.65**	**80.04**	**80.04**	**86.01**	**85.98**	**97.20**	**97.18**
Electricity Related Losses	24.44	27.02	26.87	28.20	28.05	29.89	29.82
Total	**96.09**	**107.05**	**106.91**	**114.21**	**114.03**	**127.10**	**127.00**
Electric Generators[14]							
Distillate Fuel	0.06	0.05	0.05	0.04	0.04	0.04	0.04
Residual Fuel	1.07	0.27	0.24	0.13	0.13	0.14	0.14
Petroleum Subtotal	1.13	0.32	0.29	0.17	0.16	0.19	0.18
Natural Gas	3.79	5.36	5.30	6.84	7.11	11.40	11.66
Steam Coal	18.81	21.63	21.54	22.80	22.43	23.73	23.46
Nuclear Power	7.79	7.90	7.90	7.69	7.69	6.17	6.13
Renewable Energy[15]	3.86	4.03	4.06	4.47	4.41	4.56	4.51
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.37	0.24	0.24
Total	**35.73**	**39.85**	**39.70**	**42.35**	**42.18**	**46.28**	**46.18**

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Total Energy Consumption							
Distillate Fuel	7.48	8.75	8.75	9.51	9.51	10.84	10.83
Kerosene	0.15	0.14	0.14	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.90	4.51	4.51	5.97	5.97
Liquefied Petroleum Gas	2.88	3.03	3.02	3.05	3.05	3.38	3.39
Motor Gasoline[2]	16.17	17.96	17.96	19.32	19.31	21.63	21.63
Petrochemical Feedstock	1.29	1.42	1.42	1.53	1.53	1.70	1.70
Residual Fuel	2.12	1.44	1.41	1.34	1.33	1.39	1.38
Other Petroleum[12]	4.53	4.76	4.76	5.04	5.04	5.58	5.57
Petroleum Subtotal	38.07	41.40	41.37	44.43	44.41	50.60	50.59
Natural Gas	21.90	25.78	25.73	28.52	28.78	35.40	35.66
Metallurgical Coal	0.75	0.69	0.69	0.61	0.61	0.50	0.50
Steam Coal	20.65	23.57	23.48	24.77	24.41	25.75	25.49
Net Coal Coke Imports	0.06	0.12	0.12	0.16	0.16	0.22	0.22
Coal Subtotal	21.46	24.37	24.29	25.54	25.17	26.48	26.21
Nuclear Power	7.79	7.90	7.90	7.69	7.69	6.17	6.13
Renewable Energy[17]	6.51	6.98	7.01	7.66	7.60	8.21	8.16
Methanol (M85)[11]	0.00	0.00	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
Electricity Imports[16]	0.35	0.61	0.61	0.37	0.37	0.24	0.24
Total	**96.09**	**107.05**	**106.91**	**114.21**	**114.04**	**127.10**	**127.00**
Energy Use and Related Statistics							
Delivered Energy Use	71.65	80.04	80.04	86.01	85.98	97.20	97.18
Total Energy Use	96.09	107.05	106.91	114.21	114.04	127.10	127.00
Population (millions)	273.13	288.02	288.02	300.17	300.17	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	10960	10960	12667	12667	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1692.0	1816.2	1811.4	2045.4	2042.8

[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 MCBASE.D121300A, and MCSO205H.D121300A.

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Residential	**13.12**	**12.91**	**12.91**	**13.15**	**13.23**	**13.59**	**13.65**
Primary Energy[1]	6.72	7.12	7.10	7.00	7.04	7.02	7.04
Petroleum Products[2]	7.55	9.18	9.18	9.37	9.37	9.66	9.64
Distillate Fuel	6.27	7.34	7.33	7.51	7.51	7.99	7.98
Liquefied Petroleum Gas	10.36	12.83	12.82	13.06	13.07	12.90	12.85
Natural Gas	6.52	6.63	6.62	6.52	6.56	6.56	6.59
Electricity	23.46	21.84	21.87	21.88	22.04	22.16	22.27
Commercial	**13.20**	**12.36**	**12.35**	**11.74**	**11.82**	**12.37**	**12.43**
Primary Energy[1]	5.22	5.35	5.34	5.53	5.56	5.76	5.78
Petroleum Products[2]	5.00	6.01	6.01	6.17	6.17	6.52	6.49
Distillate Fuel	4.37	5.13	5.12	5.28	5.28	5.77	5.75
Residual Fuel	2.63	3.64	3.64	3.69	3.69	3.85	3.85
Natural Gas[3]	5.34	5.31	5.30	5.49	5.53	5.72	5.75
Electricity	21.43	19.51	19.52	17.61	17.74	18.09	18.21
Industrial[4]	**5.32**	**5.49**	**5.48**	**5.44**	**5.46**	**5.85**	**5.87**
Primary Energy	3.92	4.25	4.24	4.37	4.38	4.73	4.73
Petroleum Products[2]	5.55	5.95	5.94	6.05	6.05	6.28	6.26
Distillate Fuel	4.65	5.29	5.29	5.46	5.46	5.98	5.94
Liquefied Petroleum Gas	8.50	7.94	7.93	8.00	8.00	7.86	7.81
Residual Fuel	2.78	3.37	3.36	3.42	3.42	3.58	3.58
Natural Gas[5]	2.79	3.17	3.16	3.30	3.33	3.77	3.80
Metallurgical Coal	1.65	1.58	1.58	1.54	1.54	1.44	1.44
Steam Coal	1.43	1.34	1.32	1.29	1.27	1.21	1.19
Electricity	13.01	12.30	12.30	11.21	11.30	11.60	11.71
Transportation	**8.30**	**9.27**	**9.26**	**9.45**	**9.47**	**9.32**	**9.31**
Primary Energy	8.29	9.25	9.24	9.44	9.45	9.30	9.29
Petroleum Products[2]	8.28	9.25	9.24	9.44	9.45	9.30	9.29
Distillate Fuel[6]	8.22	8.89	8.88	8.94	8.94	9.02	8.98
Jet Fuel[7]	4.70	5.24	5.23	5.46	5.46	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.63	10.92	10.94	10.68	10.68
Residual Fuel	2.46	3.10	3.10	3.18	3.18	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.18	14.24	14.25	13.88	13.83
Natural Gas[10]	7.02	6.80	6.78	7.03	7.08	7.33	7.36
Ethanol (E85)[11]	14.42	19.12	19.07	19.00	19.01	19.36	19.36
Methanol (M85)[12]	10.38	13.11	13.11	13.74	13.74	14.43	14.43
Electricity	15.58	14.29	14.21	13.53	13.62	13.03	13.17
Average End-Use Energy	**8.53**	**8.90**	**8.90**	**8.94**	**8.97**	**9.17**	**9.19**
Primary Energy	6.33	7.00	6.99	7.18	7.19	7.31	7.31
Electricity	19.40	18.10	18.11	17.18	17.31	17.57	17.68
Electric Generators[13]							
Fossil Fuel Average	1.49	1.50	1.47	1.52	1.53	1.85	1.87
Petroleum Products	2.50	3.70	3.69	4.06	4.09	4.33	4.32
Distillate Fuel	4.04	4.65	4.64	4.85	4.85	5.30	5.28
Residual Fuel	2.41	3.52	3.50	3.85	3.88	4.04	4.05
Natural Gas	2.54	2.89	2.85	3.02	3.07	3.61	3.66
Steam Coal	1.22	1.13	1.10	1.05	1.02	0.98	0.96

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Average Price to All Users[14]							
Petroleum Products[2]	7.43	8.43	8.43	8.63	8.64	8.62	8.61
Distillate Fuel	7.27	8.07	8.06	8.18	8.18	8.41	8.38
Jet Fuel	4.70	5.24	5.23	5.46	5.46	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.83	8.87	8.88	8.64	8.60
Motor Gasoline[8]	9.45	10.64	10.63	10.92	10.94	10.68	10.68
Residual Fuel	2.48	3.26	3.25	3.33	3.33	3.49	3.49
Natural Gas	4.05	4.25	4.24	4.27	4.29	4.52	4.55
Coal	1.24	1.15	1.12	1.07	1.04	1.00	0.98
Ethanol (E85)[11]	14.42	19.12	19.07	19.00	19.01	19.36	19.36
Methanol (M85)[12]	10.38	13.11	13.11	13.74	13.74	14.43	14.43
Electricity	19.40	18.10	18.11	17.18	17.31	17.57	17.68
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)							
Residential	134.05	147.53	147.55	157.75	158.52	181.60	182.16
Commercial	99.10	108.63	108.54	111.63	112.17	129.48	129.97
Industrial	110.62	121.27	121.07	126.35	126.91	151.05	151.64
Transportation	212.64	270.40	270.24	301.90	302.23	345.30	344.94
Total Non-Renewable Expenditures	556.41	647.83	647.40	697.64	699.83	807.43	808.71
Transportation Renewable Expenditures	0.14	0.42	0.42	0.61	0.61	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**647.82**	**698.25**	**700.45**	**808.29**	**809.57**

[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 MCBASE.D121300A, and MCSO205H.D121300A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, and MCSO205H.D121300A.
Projections: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, and MCSO205H.D121300A.

Table F4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Generation by Fuel Type							
Electric Generators[1]							
Coal	1835	2103	2095	2232	2184	2317	2279
Petroleum	104	32	29	18	17	19	18
Natural Gas[2]	365	574	583	867	911	1568	1604
Nuclear Power	730	740	740	720	720	577	574
Pumped Storage	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	363	384	381	390	388
Total	**3386**	**3811**	**3809**	**4220**	**4213**	**4872**	**4862**
Non-Utility Generation for Own Use	16	16	16	16	16	16	16
Distributed Generation	0	1	1	3	3	6	6
Cogenerators[4]							
Coal	47	52	52	52	52	52	52
Petroleum	9	10	10	10	10	10	10
Natural Gas	206	239	239	256	257	298	300
Other Gaseous Fuels[5]	4	6	6	7	7	8	8
Renewable Sources[3]	31	34	34	39	39	48	48
Other[6]	5	5	5	5	5	5	5
Total	**302**	**347**	**347**	**369**	**371**	**421**	**423**
Other End-Use Generators[7]	5	5	5	5	5	5	5
Sales to Utilities	150	171	171	176	176	200	200
Generation for Own Use	156	180	181	198	199	226	228
Net Imports[8]	**33**	**57**	**57**	**35**	**35**	**23**	**23**
Electricity Sales by Sector							
Residential	1146	1317	1317	1452	1450	1699	1696
Commercial	1083	1275	1273	1432	1429	1644	1641
Industrial	1063	1144	1143	1227	1225	1411	1410
Transportation	17	26	26	35	35	49	49
Total	**3309**	**3762**	**3760**	**4146**	**4139**	**4803**	**4795**
End-Use Prices (1999 cents per kwh)[9]							
Residential	8.0	7.5	7.5	7.5	7.5	7.6	7.6
Commercial	7.3	6.7	6.7	6.0	6.1	6.2	6.2
Industrial	4.4	4.2	4.2	3.8	3.9	4.0	4.0
Transportation	5.3	4.9	4.8	4.6	4.6	4.4	4.5
All Sectors Average	**6.6**	**6.2**	**6.2**	**5.9**	**5.9**	**6.0**	**6.0**
Prices by Service Category[9] **(1999 cents per kwh)**							
Generation	4.1	3.6	3.6	3.2	3.2	3.4	3.4
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)							
Sulfur Dioxide	13.82	10.39	8.37	9.70	6.87	8.95	6.38
Nitrogen Oxide	5.46	4.22	4.17	4.20	4.17	4.37	4.33

[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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Electric Generators[2]							
Capability							
Coal Steam	306.2	302.4	302.2	317.4	311.9	317.8	312.5
Other Fossil Steam[3]	138.2	129.6	126.9	121.1	118.6	117.2	115.9
Combined Cycle	20.2	49.4	55.5	124.0	132.6	230.0	234.1
Combustion Turbine/Diesel	75.6	129.7	127.4	162.1	158.8	207.7	209.9
Nuclear Power	97.4	97.5	97.5	94.2	93.7	71.6	71.6
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]	88.1	91.5	91.6	94.8	94.6	96.3	96.2
Distributed Generation[5]	0.0	2.0	2.0	6.1	6.0	14.0	13.0
Total	**745.0**	**821.5**	**822.6**	**939.4**	**935.8**	**1074.3**	**1072.9**
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	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7
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	2.4	2.4	4.3	4.3	5.4	5.4
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**11.5**	**11.5**	**13.6**	**13.6**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]							
Coal Steam	0.0	2.5	4.2	20.1	15.6	21.5	17.4
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	20.8	26.9	95.7	104.2	201.6	205.8
Combustion Turbine/Diesel	0.0	57.0	55.9	90.8	88.5	137.2	140.5
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	0.6	0.7	1.9	1.8	2.4	2.3
Distributed Generation[5]	0.0	2.0	2.0	6.1	6.0	14.0	13.0
Total	**0.0**	**82.9**	**89.8**	**214.6**	**216.0**	**376.7**	**378.9**
Cumulative Total Additions	**0.0**	**94.5**	**101.4**	**228.1**	**229.6**	**391.4**	**393.7**
Cumulative Retirements[7]							
Coal Steam	0.0	6.6	8.5	9.2	10.1	10.2	11.4
Other Fossil Steam[3]	0.0	8.5	11.2	17.0	19.5	20.9	22.2
Combined Cycle	0.0	0.0	0.0	0.3	0.3	0.3	0.3
Combustion Turbine/Diesel	0.0	3.8	4.5	5.1	5.7	5.9	6.6
Nuclear Power	0.0	0.0	0.0	3.3	3.7	25.9	25.9
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**	**19.0**	**24.3**	**34.9**	**39.5**	**63.4**	**66.5**
Cogenerators[8]							
Capability							
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	40.0	42.9	43.0	48.8	49.2
Other Gaseous Fuels	0.2	0.8	0.8	0.9	0.9	1.0	1.0
Renewable Sources[4]	5.3	5.9	5.9	6.8	6.8	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9	0.9	0.9
Total	**51.6**	**59.2**	**59.2**	**63.1**	**63.2**	**70.7**	**71.0**
Cumulative Additions[6]	**0.0**	**7.5**	**7.6**	**11.4**	**11.6**	**19.0**	**19.4**

Table F5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
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	147.8	202.8	195.9	183.2	189.1	206.7	208.4
Gross Domestic Trade	**330.0**	**328.1**	**321.2**	**286.1**	**292.0**	**206.7**	**208.4**
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)	4292.5	6044.9	5698.0	4987.6	5172.9	6227.5	6363.6
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**11603.8**	**9838.8**	**10024.2**	**6227.5**	**6363.6**
International Electricity Trade							
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	10.7	5.8	5.8	0.0	0.0
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**	**51.7**	**30.6**	**30.6**
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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Production							
Dry Gas Production[1]	18.67	20.72	20.62	23.03	23.21	28.84	29.02
Supplemental Natural Gas[2]	0.10	0.11	0.11	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.47**	**4.51**	**4.94**	**5.02**	**5.83**	**5.91**
Canada	3.29	4.28	4.32	4.68	4.77	5.46	5.54
Mexico	-0.01	-0.18	-0.18	-0.25	-0.25	-0.40	-0.40
Liquefied Natural Gas	0.10	0.37	0.37	0.51	0.51	0.77	0.77
Total Supply	**22.15**	**25.30**	**25.25**	**28.03**	**28.29**	**34.72**	**34.98**
Consumption by Sector							
Residential	4.72	5.32	5.32	5.54	5.54	6.14	6.13
Commercial	3.07	3.62	3.62	3.78	3.78	4.02	4.01
Industrial[3]	7.95	8.80	8.81	9.33	9.33	10.17	10.18
Electric Generators[4]	3.72	5.26	5.20	6.72	6.98	11.19	11.44
Lease and Plant Fuel[5]	1.23	1.35	1.34	1.49	1.50	1.83	1.84
Pipeline Fuel	0.64	0.75	0.74	0.87	0.87	1.06	1.06
Transportation[6]	0.02	0.05	0.05	0.09	0.09	0.15	0.15
Total	**21.35**	**25.14**	**25.09**	**27.82**	**28.08**	**34.55**	**34.81**
Discrepancy[7]	**0.80**	**0.16**	**0.16**	**0.21**	**0.21**	**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.

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 MCBASE.D121300A, and MCSO205H.D121300A. 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 MCBASE.D121300A, and MCSO205H.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, and MCSO205H.D121300A.

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Source Price							
Average Lower 48 Wellhead Price[1]	2.08	2.49	2.48	2.68	2.72	3.14	3.17
Average Import Price	2.29	2.48	2.48	2.41	2.42	2.67	2.72
Average[2]	**2.11**	**2.49**	**2.48**	**2.63**	**2.66**	**3.05**	**3.08**
Delivered Prices							
Residential	6.69	6.81	6.80	6.70	6.74	6.74	6.77
Commercial	5.49	5.45	5.44	5.64	5.68	5.87	5.90
Industrial[3]	2.87	3.26	3.24	3.39	3.42	3.87	3.90
Electric Generators[4]	2.59	2.94	2.90	3.08	3.12	3.68	3.73
Transportation[5]	7.21	6.99	6.97	7.22	7.27	7.53	7.56
Average[6]	**4.16**	**4.36**	**4.35**	**4.38**	**4.40**	**4.64**	**4.67**
Transmission & Distribution Margins[7]							
Residential	4.58	4.32	4.31	4.07	4.08	3.69	3.68
Commercial	3.37	2.96	2.96	3.01	3.02	2.82	2.82
Industrial[3]	0.75	0.76	0.76	0.76	0.76	0.82	0.82
Electric Generators[4]	0.48	0.45	0.42	0.45	0.46	0.63	0.65
Transportation[5]	5.10	4.49	4.48	4.59	4.61	4.48	4.47
Average[6]	**2.05**	**1.87**	**1.86**	**1.75**	**1.74**	**1.59**	**1.58**
Transmission & Distribution Revenue (billion 1999 dollars)							
Residential	21.61	22.96	22.95	22.55	22.59	22.62	22.58
Commercial	10.36	10.71	10.70	11.40	11.40	11.32	11.30
Industrial[3]	6.00	6.72	6.71	7.10	7.08	8.34	8.34
Electric Generators[4]	1.77	2.35	2.19	3.03	3.24	7.00	7.39
Transportation[5]	0.08	0.24	0.24	0.42	0.42	0.69	0.69
Total	**39.82**	**42.98**	**42.79**	**44.49**	**44.73**	**49.97**	**50.30**

[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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F9. Oil and Gas Supply

Production and Supply	1999	Projections					
		2005		2010		2020	
		Reference	SO$_2$ Sensitivity	Reference	SO$_2$ Sensitivity	Reference	SO$_2$ Sensitivity
Crude Oil							
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.42**	**20.81**	**20.80**	**21.46**	**21.44**
Production (million barrels per day)[2]							
U.S. Total	**5.88**	**5.60**	**5.60**	**5.15**	**5.14**	**5.01**	**5.03**
Lower 48 Onshore	3.27	2.75	2.75	2.49	2.48	2.63	2.65
Conventional	2.59	2.15	2.15	1.82	1.82	1.91	1.91
Enhanced Oil Recovery	0.68	0.61	0.61	0.66	0.66	0.72	0.74
Lower 48 Offshore	1.56	2.05	2.05	2.02	2.02	1.75	1.75
Alaska	1.05	0.79	0.79	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.47**	**14.03**	**14.00**	**13.43**	**13.51**
Natural Gas							
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**2.48**	**2.68**	**2.72**	**3.14**	**3.17**
Production (trillion cubic feet)[3]							
U.S. Total	**18.67**	**20.72**	**20.62**	**23.03**	**23.21**	**28.84**	**29.02**
Lower 48 Onshore	12.83	14.33	14.23	16.32	16.47	21.20	21.35
Associated-Dissolved[4]	1.80	1.51	1.51	1.34	1.34	1.35	1.35
Non-Associated	11.03	12.82	12.72	14.98	15.13	19.85	20.00
Conventional	6.64	7.19	7.17	8.31	8.39	11.38	11.37
Unconventional	4.39	5.62	5.55	6.66	6.74	8.48	8.62
Lower 48 Offshore	5.43	5.93	5.93	6.21	6.24	7.07	7.10
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.01	1.01
Non-Associated	4.50	4.85	4.85	5.13	5.17	6.06	6.09
Alaska	0.42	0.47	0.47	0.50	0.50	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**166.23**	**166.41**	**174.58**	**175.12**	**188.20**	**189.34**
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)	**17.94**	**24.11**	**24.15**	**28.67**	**29.12**	**39.25**	**39.91**

[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 MCBASE.D121300A, and MCSO205H.D121300A.

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	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Production[1]							
Appalachia	434	422	382	412	376	395	372
Interior	185	180	160	177	157	163	155
West	485	633	707	708	762	784	809
East of the Mississippi	561	554	496	545	490	525	495
West of the Mississippi	543	681	753	752	805	817	841
Total	**1105**	**1235**	**1249**	**1297**	**1295**	**1342**	**1336**
Net Imports							
Imports	9	16	16	17	17	20	20
Exports	58	60	60	58	59	56	57
Total	**-49**	**-44**	**-45**	**-40**	**-42**	**-36**	**-37**
Total Supply[2]	**1055**	**1191**	**1204**	**1256**	**1254**	**1306**	**1299**
Consumption by Sector							
Residential and Commercial	5	5	5	5	5	5	5
Industrial[3]	79	83	83	84	85	86	87
Coke Plants	28	26	26	23	23	19	19
Electric Generators[4]	922	1078	1091	1145	1142	1198	1191
Total	**1034**	**1192**	**1205**	**1257**	**1255**	**1308**	**1302**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**-1**	**-1**	**-1**	**-2**	**-2**
Average Minemouth Price							
(1999 dollars per short ton)	17.23	14.76	13.53	13.69	12.59	12.84	12.25
(1999 dollars per million Btu)	0.82	0.72	0.67	0.67	0.62	0.63	0.61
Delivered Prices (1999 dollars per short ton)[6]							
Industrial	31.46	29.43	28.92	28.41	27.88	26.55	26.18
Coke Plants	44.20	42.47	42.35	41.29	41.33	38.57	38.46
Electric Generators							
(1999 dollars per short ton)	24.78	22.62	21.66	20.84	20.08	19.40	18.92
(1999 dollars per million Btu)	1.22	1.13	1.10	1.05	1.02	0.98	0.96
Average	**25.82**	**23.53**	**22.60**	**21.72**	**20.99**	**20.15**	**19.69**
Exports[7]	37.43	36.32	36.07	35.54	35.23	33.13	32.85

[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 MCBASE.D121300A, and MCSO205H.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, and MCSO205H.D121300A.

Table F11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Electric Generators[1] (excluding cogenerators)							
Net Summer Capability							
Conventional Hydropower	78.14	78.62	78.62	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	3.16	3.28	4.31	4.16	4.34	4.20
Municipal Solid Waste[3]	2.59	3.15	3.15	3.56	3.56	4.07	4.07
Wood and Other Biomass[4]	1.52	1.68	1.68	2.04	2.04	2.37	2.37
Solar Thermal	0.33	0.35	0.35	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.09	0.09	0.21	0.21	0.54	0.54
Wind	2.60	4.43	4.43	5.51	5.51	5.78	5.78
Total	**88.07**	**91.47**	**91.60**	**94.76**	**94.61**	**96.33**	**96.18**
Generation (billion kilowatthours)							
Conventional Hydropower	307.43	299.05	299.05	298.99	298.99	297.94	297.94
Geothermal[2]	13.07	15.90	16.88	24.98	23.82	25.33	24.17
Municipal Solid Waste[3]	18.05	22.30	22.28	24.94	24.93	28.85	28.84
Wood and Other Biomass[4]	8.86	14.45	13.89	21.55	18.94	22.15	20.96
Dedicated Plants	7.56	8.67	8.67	10.88	10.88	13.35	13.35
Cofiring	1.30	5.78	5.22	10.67	8.05	8.80	7.61
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	4.46	9.42	9.42	12.33	12.33	13.10	13.10
Total	**352.79**	**362.28**	**362.68**	**384.41**	**380.62**	**390.09**	**387.74**
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	5.17	6.06	6.06	7.54	7.54
Total	**5.35**	**5.87**	**5.87**	**6.76**	**6.76**	**8.23**	**8.23**
Generation (billion kilowatthours)							
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.92	35.01	35.01	43.52	43.52
Total	**31.10**	**33.95**	**33.95**	**39.03**	**39.03**	**47.55**	**47.55**
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	0.75
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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Marketed Renewable Energy[2]							
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.44**	**0.44**
Wood	0.41	0.43	0.43	0.43	0.43	0.44	0.44
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**	**2.42**	**2.64**	**2.64**	**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	2.23	2.46	2.46	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.21**	**0.21**	**0.23**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.03	0.03	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.19	0.19	0.20	0.20
Electric Generators[5]	**3.86**	**4.03**	**4.06**	**4.47**	**4.41**	**4.56**	**4.51**
Conventional Hydroelectric	3.17	3.08	3.08	3.08	3.08	3.06	3.06
Geothermal	0.27	0.37	0.40	0.66	0.62	0.67	0.63
Municipal Solid Waste[6]	0.25	0.30	0.30	0.34	0.34	0.39	0.39
Biomass	0.12	0.18	0.17	0.26	0.23	0.27	0.26
Dedicated Plants	0.10	0.11	0.11	0.13	0.13	0.16	0.17
Cofiring	0.02	0.07	0.06	0.13	0.10	0.11	0.10
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	0.10	0.10	0.13	0.13	0.13	0.13
Total Marketed Renewable Energy	**6.61**	**7.16**	**7.19**	**7.84**	**7.78**	**8.40**	**8.35**
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**
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	0.19	0.19	0.19	0.16	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**	**0.21**	**0.21**	**0.23**	**0.24**

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[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 MCBASE.D121300A, and MCSO205H.D121300A.

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	SO$_2$ Sensitivity	Reference	SO$_2$ Sensitivity	Reference	SO$_2$ Sensitivity
Residential							
Petroleum	26.0	26.8	26.8	24.4	24.4	22.9	22.9
Natural Gas	69.5	78.6	78.7	82.0	81.9	90.8	90.7
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3
Electricity	192.6	223.2	222.4	240.4	238.7	274.7	273.7
Total	**289.3**	**330.0**	**329.2**	**348.1**	**346.3**	**389.6**	**388.5**
Commercial							
Petroleum	13.7	12.9	12.9	13.1	13.1	12.9	12.9
Natural Gas	45.4	53.5	53.5	56.0	55.8	59.4	59.3
Coal	1.7	1.8	1.8	1.9	1.9	2.0	2.0
Electricity	182.1	216.0	215.0	237.0	235.3	265.8	264.7
Total	**242.9**	**284.1**	**283.2**	**307.9**	**306.0**	**340.0**	**338.9**
Industrial[1]							
Petroleum	104.2	99.0	98.9	104.7	104.6	115.6	115.7
Natural Gas[2]	141.6	147.8	147.9	157.6	157.7	174.9	175.0
Coal	55.9	66.5	66.6	66.3	66.4	66.4	66.5
Electricity	178.8	193.9	193.1	203.0	201.7	228.1	227.5
Total	**480.4**	**507.2**	**506.4**	**531.6**	**530.4**	**584.9**	**584.6**
Transportation							
Petroleum[3]	485.8	556.8	556.9	608.6	608.6	705.1	704.9
Natural Gas[4]	9.5	11.8	11.8	14.1	14.2	17.9	18.0
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	2.9	4.4	4.4	5.7	5.7	7.9	7.8
Total[3]	**498.2**	**573.1**	**573.1**	**628.6**	**628.6**	**730.9**	**730.8**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	629.7	695.5	695.5	750.8	750.7	856.4	856.3
Natural Gas	266.0	291.8	291.9	309.7	309.7	342.9	343.0
Coal	58.8	69.6	69.6	69.5	69.5	69.6	69.7
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	556.3	637.5	634.9	686.1	681.4	776.5	773.7
Total[3]	**1510.8**	**1694.3**	**1692.0**	**1816.2**	**1811.4**	**2045.4**	**2042.8**
Electric Generators[6]							
Petroleum	20.0	6.8	6.1	3.5	3.4	3.9	3.7
Natural Gas	45.8	77.1	76.3	98.6	102.4	164.1	167.9
Coal	490.5	553.6	552.5	584.0	575.6	608.4	602.1
Total	**556.3**	**637.5**	**634.9**	**686.1**	**681.4**	**776.5**	**773.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	649.7	702.2	701.6	754.3	754.1	860.3	860.0
Natural Gas	311.8	368.9	368.2	408.2	412.1	507.1	510.8
Coal	549.3	623.1	622.1	653.5	645.1	678.0	671.8
Other[5]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1694.3**	**1692.0**	**1816.2**	**1811.4**	**2045.4**	**2042.8**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.9**	**6.1**	**6.0**	**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.

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 MCBASE.D121300A, and MCSO205H.D121300A.

Table F14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections					
		2005		2010		2020	
		Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity	Reference	SO_2 Sensitivity
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	17.93	10.76	40.77	15.24	52.28
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**281.39**	**169.55**	**300.15**	**246.09**	**382.46**
NO_x Controls (gigawatts)							
Combustion	0.00	65.84	65.31	66.93	66.42	67.57	66.92
SCR Post-combustion	0.00	84.31	87.18	85.97	87.18	89.75	96.31
SNCR Post-combustion	0.00	25.36	25.38	28.78	25.38	38.69	35.51
Coal Production by Sulfur Category (million tons)							
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	690.82	656.33	706.89	730.01	750.85
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	393.82	453.06	416.79	438.05	412.04
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	164.23	187.25	171.66	174.20	173.11

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.
SO_2 = Sulfur 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 MCBASE.D121300A, and MCSO205H.D121300A.

Appendix G

Tables for CO_2 and Integrated Sensitivity Cases

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Production										
Crude Oil and Lease Condensate	12.45	11.85	11.78	11.79	10.90	10.93	10.95	10.61	11.12	11.13
Natural Gas Plant Liquids	2.62	3.02	3.25	3.25	3.31	3.59	3.59	4.07	4.36	4.38
Dry Natural Gas	19.16	21.26	22.95	22.92	23.63	25.69	25.69	29.59	31.66	31.83
Coal	23.12	25.43	19.51	19.46	26.47	17.97	17.93	27.21	15.23	14.97
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.10	7.10
Renewable Energy[1]	6.50	6.98	8.31	8.27	7.65	10.05	9.87	8.20	10.81	10.60
Other[2]	1.65	0.57	0.36	0.36	0.33	0.30	0.30	0.33	0.33	0.34
Total	**73.30**	**77.01**	**74.06**	**73.94**	**79.98**	**76.46**	**76.25**	**86.18**	**80.61**	**80.35**
Imports										
Crude Oil[3]	18.96	23.21	22.93	22.92	25.22	24.89	24.88	26.48	25.92	25.94
Petroleum Products[4]	4.14	4.85	4.70	4.72	6.46	6.39	6.41	10.77	10.83	10.85
Natural Gas	3.63	4.90	5.54	5.55	5.49	6.42	6.42	6.60	7.50	7.56
Other Imports[5]	0.64	1.11	1.02	1.01	0.96	0.89	0.88	0.96	0.82	0.82
Total	**27.37**	**34.08**	**34.19**	**34.20**	**38.12**	**38.59**	**38.59**	**44.82**	**45.06**	**45.17**
Exports										
Petroleum[6]	1.98	1.81	1.79	1.79	1.79	1.77	1.77	1.90	1.93	1.94
Natural Gas	0.17	0.33	0.12	0.12	0.43	0.12	0.12	0.63	0.12	0.12
Coal	1.48	1.51	1.51	1.51	1.45	1.44	1.44	1.41	1.46	1.46
Total	**3.62**	**3.64**	**3.43**	**3.43**	**3.67**	**3.33**	**3.34**	**3.94**	**3.51**	**3.52**
Discrepancy[7]	**0.95**	**0.39**	**0.29**	**0.25**	**0.21**	**0.18**	**0.20**	**-0.03**	**-0.11**	**-0.02**
Consumption										
Petroleum Products[8]	38.07	41.40	41.03	41.05	44.43	44.36	44.39	50.60	50.82	50.89
Natural Gas	21.90	25.78	28.30	28.27	28.52	31.80	31.80	35.40	38.86	39.07
Coal	21.46	24.37	18.37	18.35	25.54	16.89	16.81	26.48	14.30	13.98
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.10	7.10
Renewable Energy[1]	6.51	6.98	8.31	8.28	7.66	10.06	9.88	8.21	10.82	10.60
Other[9]	0.35	0.61	0.62	0.61	0.38	0.52	0.51	0.25	0.38	0.38
Total	**96.09**	**107.05**	**104.53**	**104.47**	**114.21**	**111.54**	**111.29**	**127.10**	**122.26**	**122.02**
Net Imports - Petroleum	**21.12**	**26.26**	**25.83**	**25.85**	**29.88**	**29.51**	**29.52**	**35.36**	**34.82**	**34.86**
Prices (1999 dollars per unit)										
World Oil Price (dollars per barrel)[10]	17.35	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	2.49	3.14	3.15	2.68	3.48	3.52	3.14	4.00	4.06
Coal Minemouth Price (dollars per ton)	17.23	14.76	14.88	14.11	13.69	13.96	12.97	12.84	12.60	11.99
Average Electric Price (cents per Kwh)	6.6	6.2	7.7	7.7	5.9	7.6	7.6	6.0	7.5	7.6

[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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Energy Consumption										
Residential										
Distillate Fuel	0.86	0.88	0.89	0.89	0.81	0.81	0.81	0.75	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	0.46	0.46	0.41	0.42	0.42	0.39	0.41	0.41
Petroleum Subtotal	1.42	1.42	1.43	1.43	1.29	1.30	1.30	1.21	1.24	1.24
Natural Gas	4.85	5.46	5.35	5.35	5.69	5.53	5.53	6.30	6.12	6.11
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	0.43	0.43	0.43	0.43	0.42	0.42	0.44	0.43	0.43
Electricity	3.91	4.50	4.30	4.29	4.96	4.66	4.66	5.80	5.45	5.44
Delivered Energy	**10.62**	**11.86**	**11.55**	**11.54**	**12.42**	**11.97**	**11.96**	**13.80**	**13.29**	**13.27**
Electricity Related Losses	8.46	9.46	8.84	8.83	9.88	9.19	9.13	10.58	9.25	9.18
Total	**19.08**	**21.32**	**20.39**	**20.37**	**22.30**	**21.16**	**21.09**	**24.38**	**22.53**	**22.45**
Commercial										
Distillate Fuel	0.36	0.41	0.41	0.41	0.41	0.44	0.44	0.39	0.44	0.45
Residual Fuel	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
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	0.59	0.66	0.66	0.66	0.67	0.69	0.70	0.66	0.71	0.71
Natural Gas	3.15	3.71	3.62	3.61	3.89	3.74	3.73	4.12	4.04	4.02
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	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	3.70	4.35	4.15	4.14	4.89	4.62	4.60	5.61	5.27	5.25
Delivered Energy	**7.59**	**8.87**	**8.58**	**8.57**	**9.60**	**9.21**	**9.18**	**10.55**	**10.17**	**10.14**
Electricity Related Losses	8.00	9.15	8.54	8.51	9.74	9.11	9.02	10.23	8.94	8.86
Total	**15.59**	**18.02**	**17.12**	**17.07**	**19.34**	**18.32**	**18.20**	**20.79**	**19.11**	**19.00**
Industrial[4]										
Distillate Fuel	1.07	1.13	1.12	1.12	1.27	1.27	1.27	1.44	1.45	1.45
Liquefied Petroleum Gas	2.32	2.45	2.44	2.45	2.50	2.57	2.58	2.83	2.98	3.01
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	0.22	0.22	0.23	0.23	0.25	0.26	0.26	0.27	0.37	0.40
Motor Gasoline[2]	0.21	0.23	0.22	0.22	0.25	0.24	0.24	0.28	0.28	0.28
Other Petroleum[5]	4.29	4.49	4.49	4.49	4.76	4.78	4.79	5.25	5.38	5.39
Petroleum Subtotal	9.39	9.95	9.91	9.92	10.55	10.65	10.67	11.78	12.16	12.23
Natural Gas[6]	9.43	10.42	10.48	10.46	11.11	11.22	11.19	12.33	12.36	12.27
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.73	1.82	1.83	1.84	1.85	1.90	1.90	1.89	1.99	1.99
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.54	2.62	2.63	2.63	2.61	2.66	2.67	2.62	2.71	2.71
Renewable Energy[7]	2.15	2.42	2.40	2.40	2.64	2.64	2.64	3.08	3.08	3.08
Electricity	3.63	3.90	3.80	3.80	4.19	4.00	3.99	4.81	4.40	4.41
Delivered Energy	**27.15**	**29.32**	**29.21**	**29.20**	**31.10**	**31.17**	**31.16**	**34.62**	**34.72**	**34.70**
Electricity Related Losses	7.85	8.22	7.81	7.81	8.34	7.88	7.82	8.78	7.47	7.43
Total	**35.00**	**37.53**	**37.02**	**37.01**	**39.45**	**39.04**	**38.98**	**43.40**	**42.19**	**42.14**

Table G2. 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 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Transportation										
Distillate Fuel	5.13	6.28	6.16	6.17	6.99	6.90	6.90	8.21	8.10	8.10
Jet Fuel[8]	3.46	3.90	3.86	3.86	4.51	4.49	4.49	5.97	5.96	5.96
Motor Gasoline[2]	15.92	17.70	17.62	17.62	19.05	18.97	18.98	21.32	21.26	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	0.29	0.29	0.29	0.31	0.31	0.31	0.35	0.35	0.35
Petroleum Subtotal	25.54	29.06	28.82	28.83	31.75	31.57	31.58	36.77	36.60	36.60
Pipeline Fuel Natural Gas	0.66	0.77	0.83	0.83	0.89	0.97	0.97	1.08	1.18	1.19
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	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**	**29.99**	**29.82**	**29.83**	**32.89**	**32.78**	**32.79**	**38.23**	**38.15**	**38.16**
Electricity Related Losses	0.13	0.19	0.18	0.18	0.24	0.23	0.23	0.30	0.28	0.28
Total	**26.41**	**30.18**	**30.00**	**30.01**	**33.12**	**33.01**	**33.02**	**38.53**	**38.43**	**38.44**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.42	8.70	8.58	8.59	9.47	9.42	9.42	10.80	10.76	10.77
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.86	3.86	4.51	4.49	4.49	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.02	3.03	3.05	3.13	3.14	3.38	3.55	3.58
Motor Gasoline[2]	16.17	17.96	17.88	17.88	19.32	19.24	19.25	21.63	21.57	21.57
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	1.05	1.17	1.18	1.18	1.21	1.22	1.22	1.25	1.34	1.37
Other Petroleum[12]	4.53	4.76	4.75	4.75	5.04	5.06	5.07	5.58	5.71	5.72
Petroleum Subtotal	36.95	41.08	40.82	40.84	44.26	44.22	44.25	50.42	50.71	50.79
Natural Gas[6]	18.11	20.42	20.33	20.30	21.67	21.55	21.51	24.00	23.86	23.75
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	1.84	1.94	1.95	1.95	1.98	2.03	2.03	2.02	2.11	2.11
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	2.65	2.74	2.75	2.75	2.74	2.79	2.79	2.74	2.83	2.84
Renewable Energy[13]	2.65	2.95	2.93	2.93	3.19	3.18	3.18	3.65	3.64	3.64
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	11.29	12.84	12.34	12.32	14.15	13.39	13.36	16.39	15.28	15.26
Delivered Energy	**71.65**	**80.04**	**79.16**	**79.14**	**86.01**	**85.13**	**85.09**	**97.20**	**96.33**	**96.27**
Electricity Related Losses	24.44	27.02	25.37	25.33	28.20	26.41	26.20	29.89	25.93	25.75
Total	**96.09**	**107.05**	**104.53**	**104.47**	**114.21**	**111.54**	**111.29**	**127.10**	**122.26**	**122.02**
Electric Generators[14]										
Distillate Fuel	0.06	0.05	0.04	0.04	0.04	0.03	0.03	0.04	0.02	0.02
Residual Fuel	1.07	0.27	0.18	0.18	0.13	0.11	0.12	0.14	0.08	0.08
Petroleum Subtotal	1.13	0.32	0.21	0.22	0.17	0.14	0.14	0.19	0.10	0.10
Natural Gas	3.79	5.36	7.97	7.97	6.84	10.26	10.29	11.40	15.00	15.33
Steam Coal	18.81	21.63	15.62	15.60	22.80	14.10	14.02	23.73	11.46	11.14
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.10	7.10
Renewable Energy[15]	3.86	4.03	5.38	5.35	4.47	6.88	6.70	4.56	7.18	6.97
Electricity Imports[16]	0.35	0.61	0.62	0.61	0.37	0.51	0.50	0.24	0.37	0.37
Total	**35.73**	**39.85**	**37.71**	**37.65**	**42.35**	**39.80**	**39.57**	**46.28**	**41.21**	**41.01**

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Total Energy Consumption										
Distillate Fuel	7.48	8.75	8.62	8.63	9.51	9.45	9.45	10.84	10.78	10.79
Kerosene	0.15	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.12	0.12
Jet Fuel[8]	3.46	3.90	3.86	3.86	4.51	4.49	4.49	5.97	5.96	5.96
Liquefied Petroleum Gas	2.88	3.03	3.02	3.03	3.05	3.13	3.14	3.38	3.55	3.58
Motor Gasoline[2]	16.17	17.96	17.88	17.88	19.32	19.24	19.25	21.63	21.57	21.57
Petrochemical Feedstock	1.29	1.42	1.41	1.41	1.53	1.53	1.53	1.70	1.69	1.69
Residual Fuel	2.12	1.44	1.36	1.36	1.34	1.33	1.34	1.39	1.42	1.46
Other Petroleum[12]	4.53	4.76	4.75	4.75	5.04	5.06	5.07	5.58	5.71	5.72
Petroleum Subtotal	38.07	41.40	41.03	41.05	44.43	44.36	44.39	50.60	50.82	50.89
Natural Gas	21.90	25.78	28.30	28.27	28.52	31.80	31.80	35.40	38.86	39.07
Metallurgical Coal	0.75	0.69	0.69	0.69	0.61	0.61	0.61	0.50	0.50	0.50
Steam Coal	20.65	23.57	17.57	17.56	24.77	16.13	16.05	25.75	13.57	13.25
Net Coal Coke Imports	0.06	0.12	0.11	0.11	0.16	0.16	0.16	0.22	0.22	0.22
Coal Subtotal	21.46	24.37	18.37	18.35	25.54	16.89	16.81	26.48	14.30	13.98
Nuclear Power	7.79	7.90	7.90	7.90	7.69	7.91	7.91	6.17	7.10	7.10
Renewable Energy[17]	6.51	6.98	8.31	8.28	7.66	10.06	9.88	8.21	10.82	10.61
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.62	0.61	0.37	0.51	0.50	0.24	0.37	0.37
Total	**96.09**	**107.05**	**104.53**	**104.47**	**114.21**	**111.54**	**111.29**	**127.10**	**122.26**	**122.02**
Energy Use and Related Statistics										
Delivered Energy Use	71.65	80.04	79.16	79.14	86.01	85.13	85.09	97.20	96.33	96.27
Total Energy Use	96.09	107.05	104.53	104.47	114.21	111.54	111.29	127.10	122.26	122.02
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	10855	10855	12667	12639	12639	16515	16521	16521
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1694.3	1570.0	1570.3	1816.2	1640.0	1639.2	2045.4	1785.8	1782.5

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[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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Residential	**13.12**	**12.91**	**14.63**	**14.64**	**13.15**	**15.35**	**15.42**	**13.59**	**15.72**	**15.84**
Primary Energy[1]	6.72	7.12	7.56	7.57	7.00	7.60	7.63	7.02	7.70	7.74
Petroleum Products[2]	7.55	9.18	9.18	9.19	9.37	9.33	9.30	9.66	9.68	9.68
Distillate Fuel	6.27	7.34	7.33	7.33	7.51	7.48	7.48	7.99	8.00	8.00
Liquefied Petroleum Gas	10.36	12.83	12.83	12.85	13.06	12.96	12.86	12.90	12.84	12.85
Natural Gas	6.52	6.63	7.18	7.19	6.52	7.25	7.29	6.56	7.35	7.40
Electricity	23.46	21.84	25.85	25.88	21.88	26.81	26.94	22.16	26.62	26.85
Commercial	**13.20**	**12.36**	**15.11**	**15.12**	**11.74**	**14.83**	**14.92**	**12.37**	**15.07**	**15.21**
Primary Energy[1]	5.22	5.35	5.81	5.82	5.53	6.12	6.14	5.76	6.41	6.45
Petroleum Products[2]	5.00	6.01	6.00	6.00	6.17	6.10	6.08	6.52	6.45	6.45
Distillate Fuel	4.37	5.13	5.12	5.12	5.28	5.25	5.24	5.77	5.76	5.76
Residual Fuel	2.63	3.64	3.62	3.62	3.69	3.69	3.69	3.85	3.84	3.84
Natural Gas[3]	5.34	5.31	5.86	5.87	5.49	6.21	6.25	5.72	6.50	6.55
Electricity	21.43	19.51	24.84	24.88	17.61	23.32	23.52	18.09	23.00	23.24
Industrial[4]	**5.32**	**5.49**	**6.24**	**6.25**	**5.44**	**6.33**	**6.35**	**5.85**	**6.64**	**6.70**
Primary Energy	3.92	4.25	4.49	4.50	4.37	4.69	4.69	4.73	5.09	5.12
Petroleum Products[2]	5.55	5.95	5.93	5.95	6.05	6.06	6.04	6.28	6.31	6.31
Distillate Fuel	4.65	5.29	5.29	5.29	5.46	5.43	5.43	5.98	5.99	5.99
Liquefied Petroleum Gas	8.50	7.94	7.93	7.97	8.00	8.01	7.91	7.86	7.93	7.95
Residual Fuel	2.78	3.37	3.35	3.35	3.42	3.42	3.42	3.58	3.51	3.49
Natural Gas[5]	2.79	3.17	3.78	3.78	3.30	4.04	4.08	3.77	4.61	4.66
Metallurgical Coal	1.65	1.58	1.59	1.59	1.54	1.55	1.54	1.44	1.44	1.44
Steam Coal	1.43	1.34	1.30	1.29	1.29	1.24	1.22	1.21	1.10	1.09
Electricity	13.01	12.30	16.09	16.12	11.21	15.70	15.83	11.60	15.46	15.67
Transportation	**8.30**	**9.27**	**9.30**	**9.30**	**9.45**	**9.56**	**9.55**	**9.32**	**9.33**	**9.33**
Primary Energy	8.29	9.25	9.28	9.28	9.44	9.54	9.53	9.30	9.31	9.31
Petroleum Products[2]	8.28	9.25	9.28	9.28	9.44	9.54	9.52	9.30	9.30	9.30
Distillate Fuel[6]	8.22	8.89	8.90	8.90	8.94	8.94	8.94	9.02	9.05	9.05
Jet Fuel[7]	4.70	5.24	5.23	5.22	5.46	5.47	5.47	5.88	5.88	5.88
Motor Gasoline[8]	9.45	10.64	10.68	10.68	10.92	11.09	11.06	10.68	10.67	10.67
Residual Fuel	2.46	3.10	3.10	3.10	3.18	3.18	3.18	3.33	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.19	14.25	14.26	14.24	14.25	14.17	13.88	13.88	13.89
Natural Gas[10]	7.02	6.80	7.37	7.38	7.03	7.78	7.82	7.33	8.10	8.15
Ethanol (E85)[11]	14.42	19.12	19.17	19.18	19.00	19.15	19.15	19.36	19.46	19.47
Methanol (M85)[12]	10.38	13.11	13.31	13.32	13.74	13.84	13.83	14.43	14.42	14.42
Electricity	15.58	14.29	16.16	16.18	13.53	15.86	15.90	13.03	14.79	14.88
Average End-Use Energy	**8.53**	**8.90**	**9.72**	**9.73**	**8.94**	**9.92**	**9.94**	**9.17**	**10.01**	**10.06**
Primary Energy	6.33	7.00	7.18	7.18	7.18	7.43	7.43	7.31	7.53	7.55
Electricity	19.40	18.10	22.44	22.47	17.18	22.20	22.35	17.57	22.03	22.25
Electric Generators[13]										
Fossil Fuel Average	1.49	1.50	1.90	1.90	1.52	2.16	2.18	1.85	2.91	2.98
Petroleum Products	2.50	3.70	3.78	3.78	4.06	4.08	4.07	4.33	4.57	4.59
Distillate Fuel	4.04	4.65	4.67	4.67	4.85	4.83	4.82	5.30	5.27	5.26
Residual Fuel	2.41	3.52	3.60	3.59	3.85	3.90	3.89	4.04	4.40	4.42
Natural Gas	2.54	2.89	3.54	3.55	3.02	3.77	3.81	3.61	4.47	4.51
Steam Coal	1.22	1.13	1.04	1.04	1.05	0.97	0.96	0.98	0.86	0.85

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Average Price to All Users[14]										
Petroleum Products[2]	7.43	8.43	8.46	8.46	8.63	8.70	8.68	8.62	8.62	8.62
Distillate Fuel	7.27	8.07	8.07	8.07	8.18	8.16	8.16	8.41	8.42	8.42
Jet Fuel	4.70	5.24	5.23	5.22	5.46	5.47	5.47	5.88	5.88	5.88
Liquefied Petroleum Gas	8.84	8.83	8.84	8.87	8.87	8.85	8.76	8.64	8.69	8.70
Motor Gasoline[8]	9.45	10.64	10.68	10.68	10.92	11.09	11.06	10.68	10.67	10.67
Residual Fuel	2.48	3.26	3.25	3.25	3.33	3.33	3.33	3.49	3.48	3.47
Natural Gas	4.05	4.25	4.70	4.71	4.27	4.84	4.88	4.52	5.25	5.29
Coal	1.24	1.15	1.07	1.07	1.07	1.01	1.00	1.00	0.90	0.89
Ethanol (E85)[11]	14.42	19.12	19.17	19.18	19.00	19.15	19.15	19.36	19.46	19.47
Methanol (M85)[12]	10.38	13.11	13.31	13.32	13.74	13.84	13.83	14.43	14.42	14.42
Electricity	19.40	18.10	22.44	22.47	17.18	22.20	22.35	17.57	22.03	22.25
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)										
Residential	134.05	147.53	162.69	162.79	157.75	177.31	177.88	181.60	202.13	203.36
Commercial	99.10	108.63	128.37	128.26	111.63	135.33	135.83	129.48	152.03	152.96
Industrial	110.62	121.27	138.34	138.65	126.35	148.68	149.19	151.05	172.97	174.35
Transportation	212.64	270.40	269.28	269.26	301.90	303.67	303.26	345.30	344.16	344.20
Total Non-Renewable Expenditures	556.41	647.83	698.68	698.96	697.64	764.99	766.15	807.43	871.29	874.87
Transportation Renewable Expenditures	0.14	0.42	0.41	0.41	0.61	0.62	0.62	0.86	0.86	0.86
Total Expenditures	**556.55**	**648.25**	**699.09**	**699.37**	**698.25**	**765.61**	**766.77**	**808.29**	**872.15**	**875.73**

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[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Generation by Fuel Type										
Electric Generators[1]										
Coal	1835	2103	1551	1547	2232	1402	1392	2317	1140	1108
Petroleum	104	32	22	23	18	15	15	19	12	11
Natural Gas [2]	365	574	893	895	867	1292	1299	1568	2134	2168
Nuclear Power	730	740	740	740	720	741	741	577	665	665
Pumped Storage	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[3]	353	362	443	441	384	515	509	390	542	533
Total	**3386**	**3811**	**3648**	**3645**	**4220**	**3963**	**3955**	**4872**	**4492**	**4485**
Non-Utility Generation for Own Use	16	16	21	22	16	21	21	16	21	21
Distributed Generation	0	1	0	0	3	0	0	6	0	0
Cogenerators[4]										
Coal	47	52	52	52	52	52	52	52	51	51
Petroleum	9	10	10	10	10	10	10	10	10	10
Natural Gas	206	239	260	261	256	317	318	298	456	454
Other Gaseous Fuels[5]	4	6	6	6	7	7	7	8	8	8
Renewable Sources[3]	31	34	34	34	39	39	39	48	48	48
Other[6]	5	5	5	5	5	5	5	5	5	5
Total	**302**	**347**	**367**	**367**	**369**	**430**	**431**	**421**	**579**	**577**
Other End-Use Generators [7]	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Sales to Utilities	150	171	178	179	176	191	191	200	236	235
Generation for Own Use	156	180	194	194	198	244	245	226	348	347
Net Imports[8]	**33**	**57**	**59**	**57**	**35**	**49**	**47**	**23**	**35**	**35**
Electricity Sales by Sector										
Residential	1146	1317	1260	1259	1452	1366	1364	1699	1597	1595
Commercial	1083	1275	1216	1213	1432	1354	1348	1644	1544	1538
Industrial	1063	1144	1113	1113	1227	1171	1169	1411	1290	1291
Transportation	17	26	26	26	35	34	34	49	48	49
Total	**3309**	**3762**	**3615**	**3611**	**4146**	**3926**	**3916**	**4803**	**4479**	**4472**
End-Use Prices (1999 cents per kwh)[9]										
Residential	8.0	7.5	8.8	8.8	7.5	9.1	9.2	7.6	9.1	9.2
Commercial	7.3	6.7	8.5	8.5	6.0	8.0	8.0	6.2	7.8	7.9
Industrial	4.4	4.2	5.5	5.5	3.8	5.4	5.4	4.0	5.3	5.3
Transportation	5.3	4.9	5.5	5.5	4.6	5.4	5.4	4.4	5.0	5.1
All Sectors Average	**6.6**	**6.2**	**7.7**	**7.7**	**5.9**	**7.6**	**7.6**	**6.0**	**7.5**	**7.6**
Prices by Service Category [9] (1999 cents per kwh)										
Generation	4.1	3.6	5.0	5.0	3.2	4.8	4.9	3.4	4.9	4.9
Transmission	0.6	0.6	0.7	0.7	0.7	0.7	0.7	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	13.82	10.39	10.39	7.97	9.70	9.70	7.03	8.95	8.21	6.38
Nitrogen Oxide	5.46	4.22	3.42	3.37	4.20	3.15	3.10	4.37	2.55	2.48

[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Electric Generators[2]										
Capability										
Coal Steam	306.2	302.4	298.4	297.7	317.4	284.6	280.7	317.8	266.1	262.0
Other Fossil Steam[3]	138.2	129.6	123.6	122.7	121.1	105.8	106.3	117.2	103.4	102.3
Combined Cycle	20.2	49.4	70.8	71.4	124.0	135.6	136.6	230.0	259.8	258.5
Combustion Turbine/Diesel	75.6	129.7	109.7	108.0	162.1	133.0	130.7	207.7	173.3	176.7
Nuclear Power	97.4	97.5	97.5	97.5	94.2	96.9	96.9	71.6	84.6	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]	88.1	91.5	96.3	96.1	94.8	103.5	102.8	96.3	114.0	112.7
Distributed Generation[5]	0.0	2.0	2.2	1.8	6.1	4.3	3.9	14.0	8.6	9.0
Total	**745.0**	**821.5**	**818.1**	**814.7**	**939.4**	**883.2**	**877.5**	**1074.3**	**1029.5**	**1025.5**
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	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
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	0.1	0.1	0.1	0.3	0.3	0.3
Renewable Sources[4]	0.0	2.4	2.4	2.4	4.3	4.3	4.3	5.4	5.4	5.4
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**	**11.5**	**11.5**	**11.5**	**13.6**	**13.6**	**13.6**	**14.8**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]										
Coal Steam	0.0	2.5	0.0	0.0	20.1	0.0	0.0	21.5	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	20.8	42.2	42.8	95.7	107.1	108.1	201.6	231.4	230.0
Combustion Turbine/Diesel	0.0	57.0	38.6	36.9	90.8	63.7	61.4	137.2	104.7	108.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	0.6	5.5	5.3	1.9	10.7	9.9	2.4	20.1	18.8
Distributed Generation[5]	0.0	2.0	2.2	1.8	6.1	4.3	3.9	14.0	8.6	9.0
Total	**0.0**	**82.9**	**88.6**	**86.8**	**214.6**	**185.7**	**183.4**	**376.7**	**364.7**	**365.9**
Cumulative Total Additions	**0.0**	**94.5**	**100.1**	**98.4**	**228.1**	**199.2**	**197.0**	**391.4**	**379.5**	**380.6**
Cumulative Retirements[7]										
Coal Steam	0.0	6.6	8.1	8.8	9.2	21.9	25.8	10.2	40.4	44.4
Other Fossil Steam[3]	0.0	8.5	14.5	15.4	17.0	32.3	31.8	20.9	34.7	35.8
Combined Cycle	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.3	0.2	0.2
Combustion Turbine/Diesel	0.0	3.8	4.7	4.7	5.1	6.5	6.5	5.9	7.2	7.2
Nuclear Power	0.0	0.0	0.0	0.0	3.3	0.6	0.6	25.9	12.9	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[4]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**19.0**	**27.5**	**29.1**	**34.9**	**61.6**	**65.0**	**63.4**	**95.5**	**100.6**
Cogenerators[8]										
Capability										
Coal	8.4	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Petroleum	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
Natural Gas	33.8	40.0	42.1	42.1	42.9	50.3	50.5	48.8	70.2	70.0
Other Gaseous Fuels	0.2	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	1.1
Renewable Sources[4]	5.3	5.9	5.8	5.8	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	**51.6**	**59.2**	**61.2**	**61.2**	**63.1**	**70.6**	**70.7**	**70.7**	**92.2**	**92.0**
Cumulative Additions[6]	**0.0**	**7.5**	**9.6**	**9.6**	**11.4**	**18.9**	**19.1**	**19.0**	**40.6**	**40.3**

Table G5. Electricity Generating Capability (Continued)

(Gigawatts)

Net Summer Capability[1]	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
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	147.8	202.8	71.5	79.0	183.2	91.3	103.0	206.7	147.5	139.4
Gross Domestic Trade	**330.0**	**328.1**	**196.8**	**204.3**	**286.1**	**194.2**	**205.9**	**206.7**	**147.5**	**139.4**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	5905.8	5905.8	5905.8	4851.2	4851.2	4851.2	0.0	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4292.5	6044.9	3094.6	3427.9	4987.6	3866.3	4397.7	6227.5	6296.5	6048.5
Gross Domestic Sales (million 1999 dollars)	**12880.6**	**11950.7**	**9000.4**	**9333.7**	**9838.8**	**8717.5**	**9249.0**	**6227.5**	**6296.5**	**6048.5**
International Electricity Trade										
Firm Power Imports From Canada and Mexico[1]	27.0	10.7	11.8	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**	**75.3**	**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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Production										
Dry Gas Production[1]	18.67	20.72	22.37	22.34	23.03	25.04	25.04	28.84	30.86	31.02
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**	**4.47**	**5.29**	**5.30**	**4.94**	**6.15**	**6.15**	**5.83**	**7.21**	**7.27**
Canada	3.29	4.28	4.55	4.55	4.68	5.13	5.12	5.46	5.93	5.93
Mexico	-0.01	-0.18	0.30	0.30	-0.25	0.32	0.32	-0.40	0.36	0.36
Liquefied Natural Gas	0.10	0.37	0.45	0.45	0.51	0.71	0.71	0.77	0.93	0.99
Total Supply	**22.15**	**25.30**	**27.77**	**27.75**	**28.03**	**31.25**	**31.25**	**34.72**	**38.12**	**38.35**
Consumption by Sector										
Residential	4.72	5.32	5.21	5.21	5.54	5.39	5.38	6.14	5.96	5.95
Commercial	3.07	3.62	3.52	3.52	3.78	3.64	3.63	4.02	3.93	3.92
Industrial[3]	7.95	8.80	8.78	8.76	9.33	9.34	9.32	10.17	10.11	10.01
Electric Generators[4]	3.72	5.26	7.82	7.82	6.72	10.06	10.10	11.19	14.72	15.04
Lease and Plant Fuel[5]	1.23	1.35	1.42	1.42	1.49	1.58	1.58	1.83	1.93	1.94
Pipeline Fuel	0.64	0.75	0.81	0.81	0.87	0.94	0.94	1.06	1.15	1.16
Transportation[6]	0.02	0.05	0.05	0.05	0.09	0.09	0.09	0.15	0.15	0.15
Total	**21.35**	**25.14**	**27.61**	**27.59**	**27.82**	**31.05**	**31.04**	**34.55**	**37.95**	**38.17**
Discrepancy[7]	**0.80**	**0.16**	**0.16**	**0.16**	**0.21**	**0.21**	**0.21**	**0.17**	**0.17**	**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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A. 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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Source Price										
Average Lower 48 Wellhead Price[1]	2.08	2.49	3.14	3.15	2.68	3.48	3.52	3.14	4.00	4.06
Average Import Price	2.29	2.48	2.76	2.77	2.41	2.72	2.73	2.67	3.05	3.07
Average[2]	**2.11**	**2.49**	**3.07**	**3.08**	**2.63**	**3.33**	**3.36**	**3.05**	**3.82**	**3.87**
Delivered Prices										
Residential	6.69	6.81	7.38	7.39	6.70	7.45	7.49	6.74	7.55	7.60
Commercial	5.49	5.45	6.02	6.03	5.64	6.38	6.41	5.87	6.67	6.72
Industrial[3]	2.87	3.26	3.88	3.89	3.39	4.15	4.19	3.87	4.73	4.79
Electric Generators[4]	2.59	2.94	3.61	3.61	3.08	3.84	3.88	3.68	4.56	4.60
Transportation[5]	7.21	6.99	7.57	7.58	7.22	7.99	8.03	7.53	8.32	8.37
Average[6]	**4.16**	**4.36**	**4.82**	**4.83**	**4.38**	**4.97**	**5.00**	**4.64**	**5.39**	**5.43**
Transmission & Distribution Margins[7]										
Residential	4.58	4.32	4.31	4.31	4.07	4.12	4.12	3.69	3.73	3.73
Commercial	3.37	2.96	2.95	2.95	3.01	3.05	3.05	2.82	2.85	2.85
Industrial[3]	0.75	0.76	0.81	0.81	0.76	0.82	0.83	0.82	0.91	0.92
Electric Generators[4]	0.48	0.45	0.54	0.54	0.45	0.52	0.52	0.63	0.74	0.73
Transportation[5]	5.10	4.49	4.50	4.50	4.59	4.66	4.67	4.48	4.50	4.50
Average[6]	**2.05**	**1.87**	**1.76**	**1.76**	**1.75**	**1.65**	**1.64**	**1.59**	**1.57**	**1.56**
Transmission & Distribution Revenue (billion 1999 dollars)										
Residential	21.61	22.96	22.45	22.44	22.55	22.22	22.20	22.62	22.23	22.18
Commercial	10.36	10.71	10.40	10.39	11.40	11.11	11.09	11.32	11.23	11.19
Industrial[3]	6.00	6.72	7.12	7.10	7.10	7.70	7.70	8.34	9.23	9.21
Electric Generators[4]	1.77	2.35	4.23	4.20	3.03	5.23	5.21	7.00	10.86	10.95
Transportation[5]	0.08	0.24	0.24	0.24	0.42	0.41	0.41	0.69	0.66	0.66
Total	**39.82**	**42.98**	**44.43**	**44.37**	**44.49**	**46.66**	**46.61**	**49.97**	**54.21**	**54.19**

[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G9. Oil and Gas Supply

Production and Supply	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Crude Oil										
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.42**	**20.43**	**20.43**	**20.81**	**20.84**	**20.80**	**21.46**	**21.43**	**21.43**
Production (million barrels per day)[2]										
U.S. Total	**5.88**	**5.60**	**5.57**	**5.57**	**5.15**	**5.17**	**5.17**	**5.01**	**5.25**	**5.26**
Lower 48 Onshore	3.27	2.75	2.77	2.77	2.49	2.53	2.54	2.63	2.71	2.71
Conventional	2.59	2.15	2.16	2.17	1.82	1.89	1.90	1.91	2.02	2.03
Enhanced Oil Recovery	0.68	0.61	0.60	0.60	0.66	0.63	0.64	0.72	0.69	0.69
Lower 48 Offshore	1.56	2.05	2.01	2.01	2.02	1.99	1.99	1.75	1.90	1.91
Alaska	1.05	0.79	0.79	0.79	0.64	0.64	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**15.46**	**15.44**	**15.43**	**14.03**	**14.22**	**14.24**	**13.43**	**14.08**	**14.10**
Natural Gas										
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.49**	**3.14**	**3.15**	**2.68**	**3.48**	**3.52**	**3.14**	**4.00**	**4.06**
Production (trillion cubic feet)[3]										
U.S. Total	**18.67**	**20.72**	**22.37**	**22.34**	**23.03**	**25.04**	**25.04**	**28.84**	**30.86**	**31.02**
Lower 48 Onshore	12.83	14.33	15.59	15.58	16.32	18.01	18.02	21.20	22.79	22.92
Associated-Dissolved[4]	1.80	1.51	1.51	1.51	1.34	1.38	1.38	1.35	1.39	1.39
Non-Associated	11.03	12.82	14.08	14.06	14.98	16.63	16.64	19.85	21.40	21.53
Conventional	6.64	7.19	8.13	8.10	8.31	8.99	9.02	11.38	11.38	11.41
Unconventional	4.39	5.62	5.95	5.96	6.66	7.63	7.62	8.48	10.02	10.12
Lower 48 Offshore	5.43	5.93	6.31	6.30	6.21	6.54	6.52	7.07	7.51	7.53
Associated-Dissolved[4]	0.93	1.07	1.07	1.07	1.07	1.06	1.06	1.01	1.04	1.04
Non-Associated	4.50	4.85	5.24	5.23	5.13	5.48	5.47	6.06	6.46	6.49
Alaska	0.42	0.47	0.46	0.46	0.50	0.50	0.50	0.57	0.57	0.57
Lower 48 End of Year Reserves[3] (trillion cubic feet)	**157.41**	**166.23**	**168.11**	**168.42**	**174.58**	**188.80**	**188.32**	**188.20**	**206.82**	**207.43**
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)	**17.94**	**24.11**	**28.74**	**28.72**	**28.67**	**35.40**	**35.49**	**39.25**	**48.03**	**48.12**

[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Production[1]										
Appalachia	434	422	351	342	412	317	306	395	257	250
Interior	185	180	156	128	177	142	111	163	121	100
West	485	633	426	470	708	401	451	784	353	375
East of the Mississippi	561	554	463	427	545	425	383	525	349	322
West of the Mississippi	543	681	470	513	752	434	486	817	382	403
Total	**1105**	**1235**	**932**	**940**	**1297**	**859**	**869**	**1342**	**731**	**726**
Net Imports										
Imports	9	16	12	12	17	9	9	20	9	9
Exports	58	60	60	60	58	57	57	56	58	58
Total	**-49**	**-44**	**-48**	**-48**	**-40**	**-48**	**-48**	**-36**	**-49**	**-50**
Total Supply[2]	**1055**	**1191**	**884**	**892**	**1256**	**811**	**820**	**1306**	**682**	**676**
Consumption by Sector										
Residential and Commercial	5	5	5	5	5	5	5	5	5	5
Industrial[3]	79	83	84	84	84	87	87	86	91	91
Coke Plants	28	26	26	26	23	23	23	19	19	19
Electric Generators[4]	922	1078	770	780	1145	697	705	1198	573	564
Total	**1034**	**1192**	**885**	**894**	**1257**	**812**	**820**	**1308**	**688**	**679**
Discrepancy and Stock Change[5]**.**	**21**	**-1**	**-0**	**-2**	**-1**	**-1**	**1**	**-2**	**-6**	**-3**
Average Minemouth Price										
(1999 dollars per short ton)	17.23	14.76	14.88	14.11	13.69	13.96	12.97	12.84	12.60	11.99
(1999 dollars per million Btu)	0.82	0.72	0.71	0.68	0.67	0.67	0.63	0.63	0.60	0.58
Delivered Prices (1999 dollars per short ton)[6]										
Industrial	31.46	29.43	28.56	28.29	28.41	27.12	26.71	26.55	24.09	23.89
Coke Plants	44.20	42.47	42.71	42.70	41.29	41.41	41.33	38.57	38.57	38.66
Electric Generators										
(1999 dollars per short ton)	24.78	22.62	21.15	20.76	20.84	19.70	19.16	19.40	17.13	16.75
(1999 dollars per million Btu)	1.22	1.13	1.04	1.04	1.05	0.97	0.96	0.98	0.86	0.85
Average	**25.82**	**23.53**	**22.48**	**22.10**	**21.72**	**21.11**	**20.58**	**20.15**	**18.65**	**18.32**
Exports[7]	37.43	36.32	36.03	36.07	35.54	34.87	34.91	33.13	31.74	31.80

[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G11. Renewable Energy Generating Capability and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Electric Generators[1] (excluding cogenerators)										
Net Summer Capability										
Conventional Hydropower	78.14	78.62	79.92	79.92	78.74	80.04	80.04	78.74	80.04	80.04
Geothermal[2]	2.87	3.16	5.80	5.67	4.31	10.17	9.46	4.34	10.24	9.52
Municipal Solid Waste[3]	2.59	3.15	3.85	3.80	3.56	4.28	4.24	4.07	4.80	4.76
Wood and Other Biomass[4]	1.52	1.68	1.77	1.76	2.04	2.48	2.53	2.37	3.92	3.92
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	0.09	0.09	0.09	0.21	0.21	0.21	0.54	0.54	0.54
Wind	2.60	4.43	4.54	4.54	5.51	5.92	5.90	5.78	13.94	13.41
Total	**88.07**	**91.47**	**96.32**	**96.13**	**94.76**	**103.50**	**102.78**	**96.33**	**113.97**	**112.68**
Generation (billion kilowatthours)										
Conventional Hydropower	307.43	299.05	303.50	303.49	298.99	303.42	303.41	297.94	302.33	302.33
Geothermal[2]	13.07	15.90	46.28	45.22	24.98	80.74	75.14	25.33	81.31	75.69
Municipal Solid Waste[3]	18.05	22.30	27.75	27.39	24.94	30.65	30.30	28.85	34.62	34.28
Wood and Other Biomass[4]	8.86	14.45	54.09	54.11	21.55	84.88	84.99	22.15	81.44	80.09
Dedicated Plants	7.56	8.67	9.32	9.27	10.88	13.85	14.20	13.35	23.74	23.72
Cofiring	1.30	5.78	44.77	44.84	10.67	71.03	70.79	8.80	57.70	56.37
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	4.46	9.42	9.74	9.73	12.33	13.46	13.42	13.10	39.49	37.78
Total	**352.79**	**362.28**	**442.52**	**441.11**	**384.41**	**514.76**	**508.88**	**390.09**	**541.92**	**532.89**
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	5.10	5.10	6.06	6.06	6.06	7.54	7.56	7.56
Total	**5.35**	**5.87**	**5.80**	**5.80**	**6.76**	**6.76**	**6.76**	**8.23**	**8.26**	**8.26**
Generation (billion kilowatthours)										
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	29.92	29.52	29.52	35.01	34.95	34.95	43.52	43.62	43.62
Total	**31.10**	**33.95**	**33.55**	**33.55**	**39.03**	**38.98**	**38.98**	**47.55**	**47.65**	**47.65**
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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Marketed Renewable Energy[2]										
Residential	**0.41**	**0.43**	**0.43**	**0.43**	**0.43**	**0.42**	**0.42**	**0.44**	**0.43**	**0.43**
Wood	0.41	0.43	0.43	0.43	0.43	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**	**2.40**	**2.40**	**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	2.21	2.21	2.46	2.45	2.45	2.90	2.90	2.90
Transportation	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.21
Electric Generators[5]	**3.86**	**4.03**	**5.38**	**5.35**	**4.47**	**6.88**	**6.70**	**4.56**	**7.18**	**6.97**
Conventional Hydroelectric	3.17	3.08	3.12	3.12	3.08	3.12	3.12	3.06	3.11	3.11
Geothermal	0.27	0.37	1.20	1.17	0.66	2.30	2.12	0.67	2.31	2.14
Municipal Solid Waste[6]	0.25	0.30	0.38	0.37	0.34	0.42	0.41	0.39	0.47	0.47
Biomass	0.12	0.18	0.57	0.58	0.26	0.89	0.89	0.27	0.86	0.84
Dedicated Plants	0.10	0.11	0.10	0.10	0.13	0.15	0.15	0.16	0.25	0.25
Cofiring	0.02	0.07	0.48	0.48	0.13	0.74	0.74	0.11	0.61	0.59
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	0.10	0.10	0.10	0.13	0.14	0.14	0.13	0.41	0.39
Total Marketed Renewable Energy	**6.61**	**7.16**	**8.49**	**8.45**	**7.84**	**10.24**	**10.06**	**8.40**	**11.01**	**10.80**
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	0.19	0.19	0.19	0.19	0.19	0.16	0.17	0.17
From Cellulose	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.07	0.07	0.07
Total	**0.12**	**0.20**	**0.20**	**0.20**	**0.21**	**0.21**	**0.21**	**0.23**	**0.24**	**0.24**

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[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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

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	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Residential										
Petroleum	26.0	26.8	26.9	26.9	24.4	24.6	24.6	22.9	23.4	23.4
Natural Gas	69.5	78.6	77.0	77.0	82.0	79.7	79.6	90.8	88.2	88.0
Coal	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Electricity	192.6	223.2	180.7	180.9	240.4	177.8	177.8	274.7	182.3	181.3
Total	**289.3**	**330.0**	**285.9**	**286.0**	**348.1**	**283.5**	**283.4**	**389.6**	**295.1**	**293.9**
Commercial										
Petroleum	13.7	12.9	13.0	13.0	13.1	13.6	13.7	12.9	13.8	13.9
Natural Gas	45.4	53.5	52.1	52.0	56.0	53.8	53.7	59.4	58.2	58.0
Coal	1.7	1.8	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Electricity	182.1	216.0	174.4	174.3	237.0	176.3	175.7	265.8	176.2	174.8
Total	**242.9**	**284.1**	**241.2**	**241.0**	**307.9**	**245.6**	**245.0**	**340.0**	**250.2**	**248.6**
Industrial[1]										
Petroleum	104.2	99.0	99.1	99.4	104.7	106.8	107.0	115.6	122.7	123.8
Natural Gas[2]	141.6	147.8	148.6	148.3	157.6	159.1	158.8	174.9	175.3	174.2
Coal	55.9	66.5	66.7	66.7	66.3	67.6	67.6	66.4	68.7	68.8
Electricity	178.8	193.9	159.6	159.9	203.0	152.5	152.4	228.1	147.3	146.8
Total	**480.4**	**507.2**	**474.1**	**474.3**	**531.6**	**485.9**	**485.8**	**584.9**	**514.0**	**513.5**
Transportation										
Petroleum[3]	485.8	556.8	552.3	552.4	608.6	605.2	605.3	705.1	701.6	701.6
Natural Gas[4]	9.5	11.8	12.8	12.8	14.1	15.2	15.2	17.9	19.2	19.3
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	3.7	3.7	5.7	4.5	4.5	7.9	5.5	5.5
Total[3]	**498.2**	**573.1**	**568.8**	**568.9**	**628.6**	**624.9**	**625.1**	**730.9**	**726.4**	**726.5**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	629.7	695.5	691.3	691.7	750.8	750.2	750.6	856.4	861.6	862.7
Natural Gas	266.0	291.8	290.5	290.0	309.7	307.9	307.4	342.9	340.8	339.4
Coal	58.8	69.6	69.7	69.7	69.5	70.7	70.8	69.6	71.9	72.0
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	637.5	518.4	518.8	686.1	511.1	510.4	776.5	511.4	508.3
Total[3]	**1510.8**	**1694.3**	**1570.0**	**1570.3**	**1816.2**	**1640.0**	**1639.2**	**2045.4**	**1785.8**	**1782.5**
Electric Generators[6]										
Petroleum	20.0	6.8	4.5	4.6	3.5	3.0	3.0	3.9	2.2	2.2
Natural Gas	45.8	77.1	114.7	114.8	98.6	147.7	148.2	164.1	216.0	220.7
Coal	490.5	553.6	399.2	399.4	584.0	360.5	359.2	608.4	293.2	285.5
Total	**556.3**	**637.5**	**518.4**	**518.8**	**686.1**	**511.1**	**510.4**	**776.5**	**511.4**	**508.3**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	649.7	702.2	695.8	696.2	754.3	753.1	753.6	860.3	863.8	864.9
Natural Gas	311.8	368.9	405.2	404.8	408.2	455.6	455.5	507.1	556.8	560.1
Coal	549.3	623.1	468.9	469.2	653.5	431.2	430.0	678.0	365.1	357.5
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**	**1694.3**	**1570.0**	**1570.3**	**1816.2**	**1640.0**	**1639.2**	**2045.4**	**1785.8**	**1782.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.9**	**5.5**	**5.5**	**6.1**	**5.5**	**5.5**	**6.3**	**5.5**	**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 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.

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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Table G14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	Projections								
		2005			2010			2020		
		Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity	Reference	CO_2 Sensitivity	Integrated Sensitivity
Scrubber Retrofits (gigawatts)[1]	0.00	10.76	0.00	8.36	10.76	0.00	8.36	15.24	0.00	8.36
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**177.63**	**4.26**	**104.12**	**169.55**	**5.20**	**101.20**	**246.09**	**0.00**	**51.01**
NO_x Controls (gigawatts)										
Combustion	0.00	65.84	60.68	59.86	66.93	61.20	59.86	67.57	61.20	59.86
SCR Post-combustion	0.00	84.31	54.34	60.13	85.97	54.34	60.13	89.75	54.34	60.13
SNCR Post-combustion	0.00	25.36	26.16	25.75	28.78	26.16	25.75	38.69	26.16	25.75
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs. S/mmBtu)	472.31	598.07	405.41	447.19	656.33	377.53	429.60	730.01	329.97	348.82
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.55	451.27	363.52	350.73	453.06	327.80	312.51	438.05	269.85	262.83
High Sulfur (> 1.67 lbs. S/mmBtu)	198.66	185.83	163.35	141.70	187.25	153.91	126.57	174.20	131.38	113.93

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 MCBASE.D121300A, FDC7B05H.D121300A, and FDP7B05H.D121300A.

Appendix H

Tables for New Source Review Reference Cases

Table H1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Production					
Crude Oil and Lease Condensate	12.45	10.90	10.90	10.61	10.63
Natural Gas Plant Liquids	2.62	3.31	3.31	4.08	4.10
Dry Natural Gas	19.16	23.61	23.64	29.69	29.79
Coal	23.11	26.60	26.97	27.23	27.41
Nuclear Power	7.79	7.69	7.69	6.17	6.08
Renewable Energy[1]	6.50	7.62	7.59	8.17	8.15
Other[2]	1.65	0.30	0.31	0.33	0.33
Total	**73.29**	**80.03**	**80.40**	**86.28**	**86.50**
Imports					
Crude Oil[3]	18.96	25.11	25.22	26.55	26.54
Petroleum Products[4]	4.14	6.58	6.50	10.64	10.65
Natural Gas	3.63	5.46	5.43	6.59	6.64
Other Imports[5]	0.64	0.96	0.96	0.96	0.96
Total	**27.37**	**38.10**	**38.12**	**44.74**	**44.79**
Exports					
Petroleum[6]	1.98	1.78	1.78	1.88	1.90
Natural Gas	0.17	0.43	0.43	0.63	0.63
Coal	1.48	1.45	1.45	1.41	1.38
Total	**3.62**	**3.67**	**3.66**	**3.92**	**3.92**
Discrepancy[7]	**0.95**	**0.17**	**0.22**	**-0.04**	**-0.03**
Consumption					
Petroleum Products[8]	37.99	44.43	44.47	50.59	50.58
Natural Gas	21.98	28.47	28.47	35.48	35.64
Coal	21.46	25.69	26.04	26.48	26.69
Nuclear Power	7.79	7.69	7.69	6.17	6.08
Renewable Energy[1]	6.51	7.62	7.59	8.18	8.16
Other[9]	0.35	0.38	0.38	0.25	0.25
Total	**96.09**	**114.29**	**114.64**	**127.14**	**127.40**
Net Imports - Petroleum	**21.12**	**29.91**	**29.94**	**35.32**	**35.29**
Prices (1999 dollars per unit)					
World Oil Price (dollars per barrel)[10]	17.35	21.37	21.37	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	2.69	2.76	3.12	3.09
Coal Minemouth Price (dollars per ton)	17.22	14.48	15.79	13.48	14.28
Average Electric Price (cents per Kwh)	6.6	6.0	6.1	5.9	6.0

[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.

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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Energy Consumption					
Residential					
Distillate Fuel	0.86	0.81	0.81	0.75	0.75
Kerosene	0.10	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.41	0.41	0.39	0.39
Petroleum Subtotal	1.42	1.29	1.29	1.21	1.21
Natural Gas	4.85	5.69	5.68	6.31	6.32
Coal	0.04	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.43	0.43	0.44	0.44
Electricity	3.91	4.95	4.92	5.81	5.79
Delivered Energy	**10.62**	**12.41**	**12.37**	**13.82**	**13.81**
Electricity Related Losses	8.46	9.94	10.06	10.57	10.69
Total	**19.09**	**22.35**	**22.43**	**24.39**	**24.50**
Commercial					
Distillate Fuel	0.36	0.41	0.41	0.39	0.39
Residual Fuel	0.10	0.11	0.11	0.11	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.59	0.67	0.67	0.66	0.66
Natural Gas	3.15	3.88	3.87	4.13	4.14
Coal	0.07	0.07	0.07	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08
Electricity	3.70	4.86	4.86	5.64	5.62
Delivered Energy	**7.59**	**9.57**	**9.56**	**10.58**	**10.57**
Electricity Related Losses	8.00	9.77	9.95	10.27	10.37
Total	**15.59**	**19.34**	**19.50**	**20.85**	**20.94**
Industrial[4]					
Distillate Fuel	1.07	1.27	1.27	1.44	1.45
Liquefied Petroleum Gas	2.32	2.50	2.50	2.83	2.83
Petrochemical Feedstock	1.29	1.53	1.53	1.70	1.70
Residual Fuel	0.22	0.25	0.25	0.27	0.27
Motor Gasoline[2]	0.21	0.25	0.25	0.28	0.28
Other Petroleum[5]	4.29	4.75	4.75	5.24	5.24
Petroleum Subtotal	9.39	10.54	10.55	11.77	11.77
Natural Gas[6]	9.43	11.13	11.10	12.33	12.36
Metallurgical Coal	0.75	0.61	0.61	0.50	0.50
Steam Coal	1.73	1.85	1.77	1.89	1.82
Net Coal Coke Imports	0.06	0.16	0.16	0.22	0.22
Coal Subtotal	2.54	2.62	2.54	2.61	2.54
Renewable Energy[7]	2.15	2.64	2.64	3.08	3.08
Electricity	3.63	4.17	4.18	4.82	4.80
Delivered Energy	**27.15**	**31.11**	**31.02**	**34.62**	**34.56**
Electricity Related Losses	7.85	8.38	8.56	8.76	8.86
Total	**35.00**	**39.49**	**39.58**	**43.38**	**43.42**

Table H2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Transportation					
Distillate Fuel	5.13	6.99	6.98	8.20	8.20
Jet Fuel[8]	3.46	4.51	4.51	5.97	5.97
Motor Gasoline[2]	15.92	19.03	19.05	21.31	21.32
Residual Fuel	0.74	0.85	0.85	0.87	0.87
Liquefied Petroleum Gas	0.02	0.04	0.04	0.06	0.06
Other Petroleum[9]	0.26	0.31	0.31	0.35	0.35
Petroleum Subtotal	25.54	31.73	31.74	36.76	36.77
Pipeline Fuel Natural Gas	0.66	0.89	0.90	1.09	1.09
Compressed Natural Gas	0.02	0.09	0.09	0.16	0.16
Renewable Energy (E85)[10]	0.01	0.03	0.03	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.12	0.12	0.17	0.17
Delivered Energy	**26.28**	**32.87**	**32.88**	**38.22**	**38.23**
Electricity Related Losses	0.13	0.24	0.24	0.30	0.31
Total	**26.41**	**33.11**	**33.13**	**38.52**	**38.54**
Delivered Energy Consumption for All Sectors					
Distillate Fuel	7.42	9.47	9.47	10.79	10.79
Kerosene	0.15	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.51	4.51	5.97	5.97
Liquefied Petroleum Gas	2.88	3.05	3.05	3.38	3.39
Motor Gasoline[2]	16.17	19.31	19.32	21.62	21.63
Petrochemical Feedstock	1.29	1.53	1.53	1.70	1.70
Residual Fuel	1.05	1.21	1.21	1.25	1.25
Other Petroleum[12]	4.53	5.03	5.04	5.57	5.57
Petroleum Subtotal	36.95	44.24	44.25	50.40	50.41
Natural Gas[6]	18.11	21.69	21.64	24.01	24.07
Metallurgical Coal	0.75	0.61	0.61	0.50	0.50
Steam Coal	1.84	1.98	1.90	2.01	1.94
Net Coal Coke Imports	0.06	0.16	0.16	0.22	0.22
Coal Subtotal	2.65	2.74	2.66	2.74	2.67
Renewable Energy[13]	2.65	3.19	3.19	3.65	3.65
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity	11.29	14.10	14.08	16.44	16.37
Delivered Energy	**71.65**	**85.96**	**85.83**	**97.24**	**97.17**
Electricity Related Losses	24.44	28.33	28.82	29.90	30.23
Total	**96.09**	**114.29**	**114.64**	**127.14**	**127.40**
Electric Generators[14]					
Distillate Fuel	0.05	0.04	0.02	0.04	0.02
Residual Fuel	0.99	0.16	0.20	0.15	0.15
Petroleum Subtotal	1.05	0.20	0.22	0.19	0.17
Natural Gas	3.88	6.78	6.82	11.47	11.57
Steam Coal	18.80	22.95	23.38	23.74	24.02
Nuclear Power	7.79	7.69	7.69	6.17	6.08
Renewable Energy[15]	3.86	4.43	4.40	4.53	4.51
Electricity Imports[16]	0.35	0.37	0.37	0.24	0.24
Total	**35.73**	**42.43**	**42.89**	**46.34**	**46.60**

Table H2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Total Energy Consumption					
Distillate Fuel	7.47	9.51	9.49	10.83	10.81
Kerosene	0.15	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.51	4.51	5.97	5.97
Liquefied Petroleum Gas	2.88	3.05	3.05	3.38	3.39
Motor Gasoline[2]	16.17	19.31	19.32	21.62	21.63
Petrochemical Feedstock	1.29	1.53	1.53	1.70	1.70
Residual Fuel	2.05	1.37	1.41	1.39	1.40
Other Petroleum[12]	4.53	5.03	5.04	5.57	5.57
Petroleum Subtotal	37.99	44.43	44.47	50.59	50.58
Natural Gas	21.98	28.47	28.47	35.48	35.64
Metallurgical Coal	0.75	0.61	0.61	0.50	0.50
Steam Coal	20.65	24.93	25.28	25.76	25.96
Net Coal Coke Imports	0.06	0.16	0.16	0.22	0.22
Coal Subtotal	21.46	25.69	26.04	26.48	26.69
Nuclear Power	7.79	7.69	7.69	6.17	6.08
Renewable Energy[17]	6.51	7.62	7.59	8.18	8.16
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.37	0.37	0.24	0.24
Total	**96.09**	**114.29**	**114.64**	**127.14**	**127.40**
Energy Use and Related Statistics					
Delivered Energy Use	71.65	85.96	85.83	97.24	97.17
Total Energy Use	96.09	114.29	114.64	127.14	127.40
Population (millions)	273.13	300.17	300.17	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	12667	12667	16515	16515
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1818.8	1827.5	2045.6	2052.2

[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 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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H3. Energy Prices by Sector and Source

(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Residential	**13.12**	**13.28**	**13.49**	**13.46**	**13.55**
Primary Energy[1]	6.72	7.02	7.07	7.00	6.98
Petroleum Products[2]	7.55	9.38	9.33	9.63	9.62
Distillate Fuel	6.27	7.51	7.48	7.97	7.97
Liquefied Petroleum Gas	10.36	13.09	13.00	12.86	12.85
Natural Gas	6.52	6.53	6.60	6.54	6.51
Electricity	23.47	22.19	22.67	21.86	22.17
Commercial	**13.21**	**12.04**	**12.18**	**12.10**	**12.23**
Primary Energy[1]	5.22	5.54	5.59	5.74	5.71
Petroleum Products[2]	5.00	6.18	6.15	6.49	6.48
Distillate Fuel	4.37	5.28	5.26	5.74	5.74
Residual Fuel	2.63	3.70	3.70	3.85	3.85
Natural Gas[3]	5.34	5.51	5.57	5.70	5.67
Electricity	21.45	18.22	18.44	17.57	17.89
Industrial[4]	**5.32**	**5.51**	**5.56**	**5.77**	**5.81**
Primary Energy	3.92	4.39	4.40	4.71	4.71
Petroleum Products[2]	5.55	6.07	6.01	6.26	6.26
Distillate Fuel	4.65	5.46	5.44	5.94	5.93
Liquefied Petroleum Gas	8.50	8.04	7.94	7.82	7.81
Residual Fuel	2.78	3.43	3.43	3.58	3.58
Natural Gas[5]	2.79	3.31	3.38	3.75	3.72
Metallurgical Coal	1.66	1.55	1.54	1.44	1.44
Steam Coal	1.43	1.31	1.32	1.22	1.22
Electricity	13.02	11.62	11.80	11.20	11.45
Transportation	**8.30**	**9.50**	**9.45**	**9.31**	**9.30**
Primary Energy	8.29	9.49	9.43	9.30	9.29
Petroleum Products[2]	8.28	9.49	9.43	9.29	9.28
Distillate Fuel[6]	8.22	8.94	8.94	8.97	8.96
Jet Fuel[7]	4.70	5.47	5.46	5.88	5.88
Motor Gasoline[8]	9.45	11.01	10.92	10.69	10.67
Residual Fuel	2.46	3.18	3.18	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.28	14.19	13.81	13.82
Natural Gas[10]	7.02	7.05	7.11	7.31	7.28
Ethanol (E85)[11]	14.42	19.03	19.01	19.36	19.35
Methanol (M85)[12]	10.38	13.76	13.73	14.43	14.43
Electricity	15.60	13.40	13.74	12.96	13.05
Average End-Use Energy	**8.53**	**9.04**	**9.08**	**9.10**	**9.14**
Primary Energy	6.33	7.21	7.20	7.30	7.29
Electricity	19.41	17.62	17.91	17.17	17.47
Electric Generators[13]					
Fossil Fuel Average	1.49	1.52	1.52	1.85	1.83
Petroleum Products	2.49	3.97	3.80	4.28	4.15
Distillate Fuel	4.05	4.84	4.89	5.27	5.27
Residual Fuel	2.41	3.76	3.69	4.01	4.01
Natural Gas	2.53	3.05	3.13	3.62	3.60
Steam Coal	1.21	1.05	1.03	0.98	0.96

Table H3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Average Price to All Users[14]					
Petroleum Products[2]	7.44	8.67	8.61	8.61	8.60
Distillate Fuel	7.27	8.18	8.18	8.36	8.36
Jet Fuel	4.70	5.47	5.46	5.88	5.88
Liquefied Petroleum Gas	8.84	8.91	8.81	8.61	8.59
Motor Gasoline[8]	9.45	11.01	10.91	10.69	10.67
Residual Fuel	2.48	3.33	3.34	3.49	3.49
Natural Gas	4.05	4.29	4.36	4.51	4.48
Coal	1.23	1.07	1.06	1.00	0.98
Ethanol (E85)[11]	14.42	19.03	19.01	19.36	19.35
Methanol (M85)[12]	10.38	13.76	13.73	14.43	14.43
Electricity	19.41	17.62	17.91	17.17	17.47
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)					
Residential	134.10	159.17	161.07	180.05	181.22
Commercial	99.17	114.23	115.40	127.02	128.27
Industrial	110.67	128.27	129.01	148.87	149.52
Transportation	212.64	303.38	301.68	344.91	344.68
Total Non-Renewable Expenditures	556.57	705.06	707.17	800.86	803.69
Transportation Renewable Expenditures	0.14	0.62	0.61	0.86	0.86
Total Expenditures	**556.71**	**705.68**	**707.78**	**801.72**	**804.55**

[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 MC_NSR.D121900A, NSR_ALL.D121900A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MC_NSR.D121900A, NSR_ALL.D121900A, **Projections:** EIA, AEO2001 National Energy Modeling System runs MC_NSR.D121900A, NSR_ALL.D121900A.

Table H4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Generation by Fuel Type					
Electric Generators[1]					
Coal	1835	2235	2228	2307	2290
Petroleum	97	20	23	20	18
Natural Gas[2]	372	849	857	1594	1607
Nuclear Power	730	720	720	577	570
Pumped Storage	-1	-1	-1	-1	-1
Renewable Sources[3]	353	383	377	389	385
Total	**3386**	**4207**	**4204**	**4886**	**4867**
Non-Utility Generation for Own Use	16	17	16	16	16
Distributed Generation	0	2	3	7	7
Cogenerators[4]					
Coal	47	52	46	52	46
Petroleum	9	10	10	10	10
Natural Gas	206	261	257	297	305
Other Gaseous Fuels[5]	4	7	7	8	8
Renewable Sources[3]	31	39	39	48	48
Other[6]	5	5	5	5	5
Total	**302**	**375**	**365**	**420**	**422**
Other End-Use Generators[7]	5	5	5	5	5
Sales to Utilities	150	178	171	199	195
Generation for Own Use	156	202	199	226	232
Net Imports[8]	**33**	**35**	**35**	**23**	**23**
Electricity Sales by Sector					
Residential	1146	1451	1441	1703	1696
Commercial	1083	1426	1424	1654	1646
Industrial	1063	1223	1226	1412	1406
Transportation	17	35	35	49	49
Total	**3309**	**4134**	**4126**	**4817**	**4797**
End-Use Prices (1999 cents per kwh)[9]					
Residential	8.0	7.6	7.7	7.5	7.6
Commercial	7.3	6.2	6.3	6.0	6.1
Industrial	4.4	4.0	4.0	3.8	3.9
Transportation	5.3	4.6	4.7	4.4	4.5
All Sectors Average	**6.6**	**6.0**	**6.1**	**5.9**	**6.0**
Prices by Service Category[9] (1999 cents per kwh)					
Generation	4.1	3.3	3.4	3.2	3.3
Transmission	0.6	0.7	0.7	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0
Emissions (million short tons)					
Sulfur Dioxide	13.84	9.10	1.94	8.35	1.90
Nitrogen Oxide	5.45	3.78	1.56	3.90	1.62

[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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Electric Generators[2]					
Capability					
Coal Steam	306.2	314.4	305.9	315.1	309.1
Other Fossil Steam[3]	138.2	124.3	124.8	122.3	122.5
Combined Cycle	20.2	124.1	128.3	241.3	243.5
Combustion Turbine/Diesel	82.4	145.8	153.4	209.3	208.6
Nuclear Power	97.4	94.2	94.2	71.6	70.5
Pumped Storage	19.3	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	88.1	94.6	94.6	96.2	96.4
Distributed Generation[5]	0.0	5.4	6.3	16.3	15.8
Total	**751.8**	**922.5**	**927.1**	**1091.9**	**1086.1**
Cumulative Planned Additions[6]					
Coal Steam	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1
Combined Cycle	0.0	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	0.0	4.3	4.3	5.4	5.4
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**13.6**	**13.6**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]					
Coal Steam	0.0	20.6	29.8	22.3	33.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	95.6	99.9	212.8	215.1
Combustion Turbine/Diesel	0.0	67.4	73.3	131.9	129.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	1.8	1.7	2.3	2.5
Distributed Generation[5]	0.0	5.4	6.3	16.3	15.8
Total	**0.0**	**190.7**	**211.1**	**385.5**	**396.3**
Cumulative Total Additions	**0.0**	**204.2**	**224.7**	**400.3**	**411.0**
Cumulative Retirements[7]					
Coal Steam	0.0	12.6	31.4	13.7	31.4
Other Fossil Steam	0.0	13.8	14.3	15.8	16.6
Combined Cycle	0.0	0.2	0.3	0.2	0.3
Combustion Turbine/Diesel	0.0	4.7	5.1	5.8	6.4
Nuclear Power	0.0	3.3	3.3	25.9	27.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	0.1	0.1	0.1	0.1
Total	**0.0**	**34.7**	**54.5**	**61.4**	**81.8**
Cogenerators[8]					
Capability					
Coal	8.4	8.9	7.9	8.9	7.9
Petroleum	2.7	2.8	2.8	2.8	2.8
Natural Gas	33.8	43.4	43.0	48.8	49.8
Other Gaseous Fuels	0.2	0.9	0.9	1.0	1.0
Renewable Sources[4]	5.3	6.8	6.8	8.2	8.2
Other	1.1	0.9	0.9	0.9	0.9
Total	**51.6**	**63.6**	**62.2**	**70.7**	**70.7**
Cumulative Additions[6]	**0.0**	**12.0**	**10.5**	**19.0**	**19.1**

Table H5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Other End-Use Generators[9]					
Renewable Sources	1.0	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H6. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Interregional Electricity Trade					
Gross Domestic Firm Power Trade	182.2	102.9	102.9	0.0	0.0
Gross Domestic Economy Trade	146.6	199.8	209.6	197.4	200.2
Gross Domestic Trade	**328.8**	**302.7**	**312.5**	**197.4**	**200.2**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	4851.2	4851.2	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4208.2	5394.7	5798.0	5876.0	5927.5
Gross Domestic Sales (million 1999 dollars)	**12796.4**	**10246.0**	**10649.3**	**5876.0**	**5927.5**
International Electricity Trade					
Firm Power Imports From Canada and	27.0	5.8	5.8	0.0	0.0
Economy Imports From Canada and Mexico[1]	21.9	45.9	45.9	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**51.7**	**51.7**	**30.6**	**30.6**
Firm Power Exports To Canada and Mexico	9.2	8.7	8.7	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H7. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Production					
Dry Gas Production[1]	18.67	23.01	23.04	28.94	29.04
Supplemental Natural Gas[2]	0.10	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**4.91**	**4.88**	**5.81**	**5.87**
Canada	3.29	4.65	4.62	5.44	5.50
Mexico	-0.01	-0.25	-0.25	-0.40	-0.40
Liquefied Natural Gas	0.10	0.51	0.51	0.77	0.77
Total Supply	**22.15**	**27.98**	**27.98**	**34.81**	**34.96**
Consumption by Sector					
Residential	4.72	5.54	5.53	6.14	6.15
Commercial	3.07	3.78	3.77	4.02	4.03
Industrial[3]	7.95	9.36	9.33	10.17	10.20
Electric Generators[4]	3.80	6.66	6.70	11.26	11.35
Lease and Plant Fuel[5]	1.23	1.49	1.48	1.84	1.84
Pipeline Fuel	0.64	0.87	0.87	1.06	1.07
Transportation[6]	0.02	0.09	0.09	0.15	0.15
Total	**21.44**	**27.78**	**27.77**	**34.64**	**34.79**
Discrepancy[7]	**0.71**	**0.20**	**0.21**	**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.

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 MC_NSR.D121900A, NSR_ALL.D121900A. 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 MC_NSR.D121900A, NSR_ALL.D121900A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MC_NSR.D121900A, NSR_ALL.D121900A.

Table H8. Natural Gas Prices, Margins, and Revenue
(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Source Price					
Average Lower 48 Wellhead Price[1]	2.08	2.69	2.76	3.12	3.09
Average Import Price	2.29	2.41	2.46	2.66	2.68
Average[2]	**2.11**	**2.64**	**2.70**	**3.04**	**3.01**
Delivered Prices					
Residential	6.69	6.71	6.78	6.72	6.69
Commercial	5.49	5.66	5.72	5.85	5.82
Industrial[3]	2.87	3.40	3.47	3.85	3.82
Electric Generators[4]	2.58	3.11	3.19	3.68	3.67
Transportation[5]	7.21	7.24	7.30	7.51	7.48
Average[6]	**4.15**	**4.40**	**4.47**	**4.63**	**4.60**
Transmission & Distribution Margins[7]					
Residential	4.58	4.07	4.08	3.68	3.68
Commercial	3.37	3.01	3.02	2.82	2.81
Industrial[3]	0.75	0.76	0.77	0.82	0.81
Electric Generators[4]	0.47	0.47	0.49	0.65	0.66
Transportation[5]	5.10	4.59	4.60	4.48	4.47
Average[6]	**2.04**	**1.76**	**1.77**	**1.59**	**1.59**
Transmission & Distribution Revenue (billion 1999 dollars)					
Residential	21.61	22.55	22.54	22.62	22.63
Commercial	10.36	11.40	11.39	11.31	11.33
Industrial[3]	6.00	7.14	7.17	8.32	8.28
Electric Generators[4]	1.78	3.11	3.29	7.30	7.47
Transportation[5]	0.08	0.42	0.42	0.69	0.69
Total	**39.83**	**44.62**	**44.80**	**50.24**	**50.39**

[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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H9. Oil and Gas Supply

Production and Supply	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Crude Oil					
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.80**	**20.82**	**21.43**	**21.45**
Production (million barrels per day)[2]					
U.S. Total	**5.88**	**5.15**	**5.15**	**5.01**	**5.02**
Lower 48 Onshore	3.27	2.48	2.48	2.62	2.63
Conventional	2.59	1.83	1.82	1.90	1.91
Enhanced Oil Recovery	0.68	0.66	0.66	0.72	0.72
Lower 48 Offshore	1.56	2.02	2.02	1.75	1.75
Alaska	1.05	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion barrels)[2]	**18.33**	**14.03**	**14.03**	**13.42**	**13.47**
Natural Gas					
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**2.69**	**2.76**	**3.12**	**3.09**
Production (trillion cubic feet)[3]					
U.S. Total	**18.67**	**23.01**	**23.04**	**28.94**	**29.04**
Lower 48 Onshore	12.83	16.31	16.12	21.22	21.36
Associated-Dissolved[4]	1.80	1.34	1.34	1.35	1.35
Non-Associated	11.03	14.97	14.78	19.88	20.01
Conventional	6.64	8.27	8.04	11.40	11.47
Unconventional	4.39	6.70	6.74	8.48	8.53
Lower 48 Offshore	5.43	6.20	6.41	7.14	7.11
Associated-Dissolved[4]	0.93	1.07	1.07	1.01	1.01
Non-Associated	4.50	5.12	5.34	6.13	6.10
Alaska	0.42	0.50	0.50	0.57	0.57
Lower 48 End of Year Reserves [3] (trillion cubic feet)	**157.41**	**175.79**	**175.29**	**188.23**	**192.67**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.10**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.94**	**28.80**	**28.71**	**38.82**	**38.85**

[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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H10. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Production[1]					
Appalachia	433	440	465	416	434
Interior	186	189	234	183	219
West	485	660	590	730	672
East of the Mississippi	561	584	657	563	623
West of the Mississippi	543	704	632	766	702
Total	**1104**	**1288**	**1289**	**1329**	**1325**
Net Imports					
Imports	9	17	17	20	20
Exports	58	58	57	56	55
Total	**-49**	**-40**	**-40**	**-36**	**-36**
Total Supply[2]	**1055**	**1248**	**1249**	**1293**	**1289**
Consumption by Sector					
Residential and Commercial	5	5	5	5	5
Industrial[3]	79	84	81	86	83
Coke Plants	28	23	23	19	19
Electric Generators[4]	922	1137	1140	1184	1183
Total	**1034**	**1250**	**1249**	**1294**	**1290**
Discrepancy and Stock Change[5]**.**	**21**	**-2**	**-0**	**-2**	**-1**
Average Minemouth Price					
(1999 dollars per short ton)	17.22	14.48	15.79	13.48	14.28
(1999 dollars per million Btu)	0.82	0.70	0.75	0.66	0.69
Delivered Prices (1999 dollars per short ton)[6]					
Industrial	31.44	28.75	28.82	26.84	26.62
Coke Plants	44.38	41.42	41.19	38.51	38.49
Electric Generators					
(1999 dollars per short ton)	24.76	21.19	21.20	19.65	19.40
(1999 dollars per million Btu)	1.21	1.05	1.03	0.98	0.96
Average	**25.80**	**22.07**	**22.06**	**20.41**	**20.15**
Exports[7]	37.54	35.73	35.13	33.14	32.57

[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 MC_NSR.D121900A, NSR_ALL.D121900A. **Projections:** EIA, AEO2001 National Energy Modeling System runs MC_NSR.D121900A, NSR_ALL.D121900A.

Table H11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Electric Generators[1]					
(excluding cogenerators)					
Net Summer Capability					
Conventional Hydropower	78.14	78.74	78.74	78.74	78.74
Geothermal[2]	2.87	4.16	4.36	4.22	4.43
Municipal Solid Waste[3]	2.59	3.56	3.33	4.07	3.89
Wood and Other Biomass[4]	1.52	2.04	2.04	2.37	2.59
Solar Thermal	0.33	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.21	0.21	0.54	0.54
Wind	2.60	5.51	5.51	5.78	5.78
Total	**88.07**	**94.61**	**94.59**	**96.20**	**96.45**
Generation (billion kilowatthours)					
Conventional Hydropower	307.43	298.99	298.99	297.95	297.95
Geothermal[2]	13.07	23.79	25.39	24.32	25.99
Municipal Solid Waste[3]	18.05	24.97	23.18	28.88	27.46
Wood and Other Biomass[4]	9.16	21.26	15.56	22.18	17.37
Dedicated Plants	7.56	10.88	10.88	13.35	14.79
Cofiring	1.60	10.38	4.67	8.83	2.59
Solar Thermal	0.89	1.11	1.11	1.37	1.37
Solar Photovoltaic	0.03	0.51	0.51	1.36	1.36
Wind	4.46	12.33	12.33	13.10	13.10
Total	**353.09**	**382.97**	**377.07**	**389.16**	**384.60**
Cogenerators[5]					
Net Summer Capability					
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	6.06	6.06	7.54	7.54
Total	**5.35**	**6.76**	**6.76**	**8.23**	**8.23**
Generation (billion kilowatthours)					
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	35.01	35.01	43.52	43.52
Total	**31.10**	**39.03**	**39.03**	**47.55**	**47.55**
Other End-Use Generators[6]					
Net Summer Capability					
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.35
Total	**1.00**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)					
Conventional Hydropower[7]	4.57	4.43	4.43	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.75	0.75	0.75	0.75
Total	**4.59**	**5.18**	**5.18**	**5.17**	**5.17**

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[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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H12. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Marketed Renewable Energy[2]					
Residential	**0.41**	**0.43**	**0.43**	**0.44**	**0.44**
Wood	0.41	0.43	0.43	0.44	0.44
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.64**	**2.64**	**3.08**	**3.08**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.46	2.46	2.90	2.90
Transportation	**0.12**	**0.21**	**0.21**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.03	0.03	0.04	0.04
Ethanol used in Gasoline Blending	0.12	0.19	0.19	0.21	0.21
Electric Generators[5]	**3.86**	**4.43**	**4.40**	**4.53**	**4.51**
Conventional Hydroelectric	3.17	3.08	3.08	3.06	3.06
Geothermal	0.27	0.62	0.67	0.64	0.69
Municipal Solid Waste[6]	0.25	0.34	0.32	0.39	0.37
Biomass	0.12	0.25	0.20	0.27	0.22
Dedicated Plants	0.10	0.13	0.14	0.17	0.19
Cofiring	0.02	0.12	0.06	0.11	0.03
Solar Thermal	0.01	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.13	0.13	0.13	0.13
Total Marketed Renewable Energy	**6.62**	**7.80**	**7.77**	**8.38**	**8.36**
Non-Marketed Renewable Energy[7] **Selected Consumption**					
Residential	**0.02**	**0.03**	**0.03**	**0.04**	**0.03**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Ethanol					
From Corn	0.12	0.19	0.19	0.17	0.17
From Cellulose	0.00	0.02	0.02	0.07	0.07
Total	**0.12**	**0.21**	**0.21**	**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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Residential					
Petroleum	26.0	24.4	24.4	22.9	22.9
Natural Gas	69.5	81.9	81.8	90.8	91.0
Coal	1.1	1.3	1.3	1.3	1.3
Electricity	192.6	241.7	244.4	274.7	277.4
Total	**289.3**	**349.4**	**352.0**	**389.7**	**392.5**
Commercial					
Petroleum	13.7	13.1	13.1	12.9	12.9
Natural Gas	45.4	55.9	55.8	59.4	59.6
Coal	1.7	1.9	1.9	2.0	2.0
Electricity	182.1	237.6	241.6	266.8	269.2
Total	**242.9**	**308.5**	**312.3**	**341.0**	**343.6**
Industrial[1]					
Petroleum	104.2	104.7	104.8	115.5	115.5
Natural Gas[2]	141.6	157.8	157.5	174.9	175.4
Coal	55.9	66.3	64.3	66.3	64.5
Electricity	178.8	203.8	208.0	227.7	230.0
Total	**480.4**	**532.6**	**534.5**	**584.4**	**585.3**
Transportation					
Petroleum[3]	485.8	608.4	608.5	704.7	704.8
Natural Gas[4]	9.5	14.1	14.2	17.9	18.0
Other[5]	0.0	0.1	0.1	0.1	0.1
Electricity	2.9	5.8	5.9	7.8	8.0
Total[3]	**498.2**	**628.3**	**628.7**	**730.5**	**730.8**
Total Carbon Dioxide Emissions by Delivered Fuel					
Petroleum[3]	629.7	750.5	750.7	855.9	856.1
Natural Gas	266.0	309.8	309.3	343.1	344.0
Coal	58.8	69.5	67.5	69.5	67.7
Other[5]	0.0	0.1	0.1	0.1	0.1
Electricity	556.3	688.9	699.9	777.0	784.4
Total[3]	**1510.8**	**1818.8**	**1827.5**	**2045.6**	**2052.2**
Electric Generators[6]					
Petroleum	20.0	4.1	4.6	4.0	3.6
Natural Gas	45.8	97.7	98.2	165.2	166.6
Coal	490.5	587.1	597.0	607.9	614.3
Total	**556.3**	**688.9**	**699.9**	**777.0**	**784.4**
Total Carbon Dioxide Emissions by Primary Fuel[7]					
Petroleum[3]	649.7	754.6	755.4	859.9	859.7
Natural Gas	311.8	407.5	407.5	508.3	510.5
Coal	549.3	656.6	664.5	677.3	681.9
Other[5]	0.0	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1818.8**	**1827.5**	**2045.6**	**2052.2**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**6.1**	**6.1**	**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.

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 MC_NSR.D121900A, NSR_ALL.D121900A.

Table H14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	2010		2020	
		NSR 32	NSR All	NSR 32	NSR All
Scrubber Retrofits (gigawatts)[1]	0.00	40.23	195.23	40.23	195.23
SO_2 Allowance Price					
(1999 dollars per ton)	**0.00**	**137.26**	**0.00**	**162.35**	**0.00**
NO_x Controls (gigawatts)					
Combustion	0.00	64.01	82.26	64.51	82.26
SCR Post-combustion	0.00	93.10	276.12	98.71	276.12
SNCR Post-combustion	0.00	26.81	19.19	31.72	19.19
Coal Production by Sulfur Category					
(million tons)					
Low Sulfur (< .61 lbs. S/mmBtu)	472.18	612.42	491.75	675.10	565.24
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	432.67	475.21	496.67	461.05	476.50
High Sulfur (> 1.67 lbs. S/mmBtu)	199.58	200.48	300.20	192.98	282.84

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 MC_NSR.D121900A, NSR_ALL.D121900A.

Appendix I

Tables for New Source Review Integrated Cases

Table I1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Production					
Crude Oil and Lease Condensate	12.45	10.96	10.95	11.44	11.49
Natural Gas Plant Liquids	2.62	3.67	3.71	4.34	4.39
Dry Natural Gas	19.16	26.24	26.53	31.55	31.92
Coal	23.11	14.41	14.14	12.06	11.64
Nuclear Power	7.79	7.91	7.91	7.32	7.24
Renewable Energy[1]	6.50	10.48	10.34	12.78	12.00
Other[2]	1.65	0.30	0.30	0.33	0.34
Total	**73.30**	**73.97**	**73.88**	**79.83**	**79.02**
Imports					
Crude Oil[3]	18.96	24.82	24.86	25.72	25.63
Petroleum Products[4]	4.14	6.64	6.62	10.90	11.04
Natural Gas	3.63	6.64	6.66	7.97	8.06
Other Imports[5]	0.64	0.75	0.75	0.69	0.69
Total	**27.37**	**38.86**	**38.89**	**45.28**	**45.42**
Exports					
Petroleum[6]	1.98	1.77	1.78	1.93	1.93
Natural Gas	0.17	0.12	0.12	0.12	0.12
Coal	1.48	1.51	1.46	1.44	1.44
Total	**3.62**	**3.41**	**3.36**	**3.49**	**3.49**
Discrepancy[7]	**0.95**	**0.25**	**0.31**	**0.01**	**0.14**
Consumption					
Petroleum Products[8]	38.03	44.62	44.65	50.98	51.09
Natural Gas	21.95	32.55	32.87	39.21	39.66
Coal	21.45	13.21	12.94	11.07	10.55
Nuclear Power	7.79	7.91	7.91	7.32	7.24
Renewable Energy[1]	6.51	10.49	10.35	12.79	12.01
Other[9]	0.35	0.38	0.38	0.25	0.25
Total	**96.09**	**109.17**	**109.10**	**121.61**	**120.81**
Net Imports - Petroleum	**21.12**	**29.69**	**29.70**	**34.69**	**34.74**
Prices (1999 dollars per unit)					
World Oil Price (dollars per barrel)[10]	17.35	21.37	21.37	22.41	22.41
Gas Wellhead Price (dollars per Mcf)[11]	2.08	4.33	4.33	4.23	4.48
Coal Minemouth Price (dollars per ton)	17.21	12.44	13.92	11.47	12.82
Average Electric Price (cents per Kwh)	6.6	8.4	8.1	7.7	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.

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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Energy Consumption					
Residential					
Distillate Fuel	0.86	0.81	0.81	0.77	0.77
Kerosene	0.10	0.07	0.07	0.07	0.07
Liquefied Petroleum Gas	0.46	0.42	0.42	0.41	0.41
Petroleum Subtotal	1.42	1.31	1.31	1.25	1.24
Natural Gas	4.85	5.38	5.38	6.03	5.98
Coal	0.04	0.05	0.05	0.05	0.05
Renewable Energy[1]	0.41	0.42	0.42	0.42	0.42
Electricity	3.91	4.55	4.59	5.41	5.39
Delivered Energy	**10.62**	**11.71**	**11.75**	**13.15**	**13.08**
Electricity Related Losses	8.46	8.61	8.65	9.19	9.02
Total	**19.09**	**20.32**	**20.40**	**22.34**	**22.10**
Commercial					
Distillate Fuel	0.36	0.47	0.47	0.51	0.52
Residual Fuel	0.10	0.11	0.11	0.11	0.11
Kerosene	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.08	0.09	0.09	0.10	0.10
Motor Gasoline[2]	0.03	0.03	0.03	0.03	0.03
Petroleum Subtotal	0.59	0.72	0.73	0.77	0.78
Natural Gas	3.15	3.60	3.59	3.99	3.91
Coal	0.07	0.07	0.07	0.08	0.08
Renewable Energy[3]	0.08	0.08	0.08	0.08	0.08
Electricity	3.70	4.48	4.52	5.18	5.18
Delivered Energy	**7.59**	**8.96**	**8.99**	**10.11**	**10.03**
Electricity Related Losses	8.00	8.48	8.52	8.81	8.67
Total	**15.59**	**17.44**	**17.52**	**18.91**	**18.70**
Industrial[4]					
Distillate Fuel	1.07	1.29	1.28	1.46	1.46
Liquefied Petroleum Gas	2.32	2.67	2.68	3.04	3.11
Petrochemical Feedstock	1.29	1.53	1.53	1.69	1.69
Residual Fuel	0.22	0.39	0.38	0.41	0.41
Motor Gasoline[2]	0.21	0.24	0.24	0.28	0.28
Other Petroleum[5]	4.29	4.85	4.83	5.41	5.44
Petroleum Subtotal	9.39	10.96	10.95	12.29	12.39
Natural Gas[6]	9.43	10.77	10.74	12.18	11.94
Metallurgical Coal	0.75	0.60	0.60	0.50	0.49
Steam Coal	1.73	1.92	1.70	2.00	1.78
Net Coal Coke Imports	0.06	0.16	0.16	0.23	0.23
Coal Subtotal	2.54	2.69	2.46	2.72	2.50
Renewable Energy[7]	2.15	2.64	2.64	3.12	3.15
Electricity	3.63	3.94	3.96	4.32	4.35
Delivered Energy	**27.15**	**31.00**	**30.75**	**34.62**	**34.33**
Electricity Related Losses	7.85	7.46	7.46	7.33	7.28
Total	**35.00**	**38.45**	**38.21**	**41.96**	**41.61**

Table I2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Transportation					
Distillate Fuel	5.13	6.87	6.87	8.09	8.08
Jet Fuel[8]	3.46	4.49	4.49	5.96	5.96
Motor Gasoline[2]	15.92	18.94	18.94	21.25	21.24
Residual Fuel	0.74	0.85	0.85	0.86	0.86
Liquefied Petroleum Gas	0.02	0.04	0.04	0.06	0.06
Other Petroleum[9]	0.26	0.31	0.31	0.35	0.35
Petroleum Subtotal	25.54	31.50	31.50	36.57	36.55
Pipeline Fuel Natural Gas	0.66	0.99	1.01	1.19	1.21
Compressed Natural Gas	0.02	0.09	0.09	0.15	0.15
Renewable Energy (E85)[10]	0.01	0.03	0.03	0.04	0.04
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity	0.06	0.12	0.12	0.17	0.17
Delivered Energy	**26.28**	**32.73**	**32.75**	**38.12**	**38.12**
Electricity Related Losses	0.13	0.22	0.22	0.28	0.28
Total	**26.41**	**32.96**	**32.97**	**38.40**	**38.40**
Delivered Energy Consumption for All Sectors					
Distillate Fuel	7.42	9.44	9.43	10.82	10.82
Kerosene	0.15	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.49	4.49	5.96	5.96
Liquefied Petroleum Gas	2.88	3.23	3.24	3.61	3.67
Motor Gasoline[2]	16.17	19.21	19.22	21.56	21.55
Petrochemical Feedstock	1.29	1.53	1.53	1.69	1.69
Residual Fuel	1.05	1.34	1.34	1.38	1.38
Other Petroleum[12]	4.53	5.13	5.12	5.74	5.77
Petroleum Subtotal	36.95	44.49	44.48	50.87	50.97
Natural Gas[6]	18.11	20.82	20.81	23.54	23.18
Metallurgical Coal	0.75	0.60	0.60	0.50	0.49
Steam Coal	1.84	2.05	1.82	2.12	1.91
Net Coal Coke Imports	0.06	0.16	0.16	0.23	0.23
Coal Subtotal	2.65	2.81	2.59	2.85	2.63
Renewable Energy[13]	2.65	3.18	3.18	3.67	3.69
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity	11.29	13.10	13.19	15.07	15.08
Delivered Energy	**71.65**	**84.40**	**84.25**	**96.00**	**95.56**
Electricity Related Losses	24.44	24.76	24.85	25.61	25.25
Total	**96.09**	**109.17**	**109.10**	**121.61**	**120.81**
Electric Generators[14]					
Distillate Fuel	0.05	0.03	0.02	0.02	0.02
Residual Fuel	1.03	0.11	0.15	0.08	0.10
Petroleum Subtotal	1.08	0.13	0.17	0.10	0.11
Natural Gas	3.85	11.74	12.07	15.67	16.48
Steam Coal	18.80	10.40	10.36	8.22	7.93
Nuclear Power	7.79	7.91	7.91	7.32	7.24
Renewable Energy[15]	3.86	7.31	7.17	9.12	8.32
Electricity Imports[16]	0.35	0.37	0.37	0.24	0.24
Total	**35.73**	**37.86**	**38.04**	**40.68**	**40.32**

Table I2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Total Energy Consumption					
Distillate Fuel	7.47	9.46	9.45	10.84	10.84
Kerosene	0.15	0.13	0.13	0.12	0.12
Jet Fuel[8]	3.46	4.49	4.49	5.96	5.96
Liquefied Petroleum Gas	2.88	3.23	3.24	3.61	3.67
Motor Gasoline[2]	16.17	19.21	19.22	21.56	21.55
Petrochemical Feedstock	1.29	1.53	1.53	1.69	1.69
Residual Fuel	2.08	1.45	1.49	1.46	1.48
Other Petroleum[12]	4.53	5.13	5.12	5.74	5.77
Petroleum Subtotal	38.03	44.62	44.65	50.98	51.09
Natural Gas	21.95	32.55	32.87	39.21	39.66
Metallurgical Coal	0.75	0.60	0.60	0.50	0.49
Steam Coal	20.64	12.45	12.18	10.35	9.83
Net Coal Coke Imports	0.06	0.16	0.16	0.23	0.23
Coal Subtotal	21.45	13.21	12.94	11.07	10.55
Nuclear Power	7.79	7.91	7.91	7.32	7.24
Renewable Energy[17]	6.51	10.49	10.35	12.79	12.01
Methanol (M85)[11]	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00
Electricity Imports[16]	0.35	0.37	0.37	0.24	0.24
Total	**96.09**	**109.17**	**109.10**	**121.61**	**120.81**
Energy Use and Related Statistics					
Delivered Energy Use	71.65	84.40	84.25	96.00	95.56
Total Energy Use	96.09	109.17	109.10	121.61	120.81
Population (millions)	273.13	300.17	300.17	325.24	325.24
Gross Domestic Product (billion 1996 dollars)	8876	12630	12632	16521	16521
Total Carbon Dioxide Emissions (million metric tons carbon equivalent)	1510.8	1562.5	1560.0	1711.9	1706.5

[1] Includes wood used for residential heating.
[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3] Includes commercial sector electricity cogenerated by using wood and wood waste, landfill gas, municipal solid waste, and other biomass.
[4] Fuel consumption includes consumption for cogeneration, which produces electricity and other useful thermal energy.
[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6] Includes lease and plant fuel and consumption by cogenerators, excludes consumption by nonutility generators.
[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass; includes cogeneration, both for sale to the grid and for own use.
[8] Includes only kerosene type.
[9] Includes aviation gas and lubricants.
[10] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[11] M85 is 85 percent methanol and 15 percent motor gasoline.
[12] Includes unfinished oils, natural gasoline, motor gasoline blending compounds, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14] Includes consumption of energy by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.
[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes cogeneration. Excludes net electricity imports.
[16] In 1998 approximately 70 percent of the U.S. electricity imports were provided by renewable sources (hydroelectricity); EIA does not project future proportions for the fuel source of imported electricity.
[17] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I3. Energy Prices by Sector and Source

(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Residential	**13.12**	**16.57**	**16.31**	**16.11**	**16.41**
Primary Energy[1]	6.72	8.19	8.18	7.91	8.10
Petroleum Products[2]	7.55	9.32	9.34	9.72	9.80
Distillate Fuel	6.27	7.45	7.46	7.99	8.03
Liquefied Petroleum Gas	10.36	12.97	13.03	13.02	13.23
Natural Gas	6.52	7.97	7.97	7.59	7.80
Electricity	23.46	28.99	28.25	27.24	27.62
Commercial	**13.20**	**16.51**	**16.09**	**15.44**	**15.80**
Primary Energy[1]	5.22	6.68	6.68	6.59	6.77
Petroleum Products[2]	5.00	6.05	6.06	6.41	6.44
Distillate Fuel	4.37	5.21	5.21	5.75	5.77
Residual Fuel	2.63	3.69	3.69	3.84	3.85
Natural Gas[3]	5.34	6.92	6.92	6.73	6.94
Electricity	21.44	26.13	25.23	23.71	24.12
Industrial[4]	**5.32**	**6.90**	**6.86**	**6.80**	**7.02**
Primary Energy	3.92	5.02	5.07	5.22	5.40
Petroleum Products[2]	5.55	6.06	6.09	6.37	6.45
Distillate Fuel	4.65	5.40	5.40	5.99	6.01
Liquefied Petroleum Gas	8.50	8.10	8.16	8.14	8.34
Residual Fuel	2.78	3.34	3.34	3.49	3.50
Natural Gas[5]	2.79	4.81	4.81	4.84	5.06
Metallurgical Coal	1.65	1.54	1.53	1.44	1.43
Steam Coal	1.43	1.17	1.18	1.05	1.05
Electricity	13.02	17.72	16.93	15.94	16.22
Transportation	**8.30**	**9.58**	**9.57**	**9.34**	**9.34**
Primary Energy	8.29	9.55	9.55	9.31	9.32
Petroleum Products[2]	8.28	9.54	9.54	9.31	9.31
Distillate Fuel[6]	8.22	8.92	8.93	9.05	9.06
Jet Fuel[7]	4.70	5.46	5.46	5.88	5.88
Motor Gasoline[8]	9.45	11.11	11.10	10.68	10.68
Residual Fuel	2.46	3.18	3.18	3.33	3.33
Liquid Petroleum Gas[9]	12.87	14.28	14.32	14.01	14.26
Natural Gas[10]	7.02	8.47	8.47	8.30	8.49
Ethanol (E85)[11]	14.42	19.28	19.28	19.50	19.52
Methanol (M85)[12]	10.38	14.33	14.26	14.42	14.42
Electricity	15.60	16.75	15.70	14.78	14.76
Average End-Use Energy	**8.53**	**10.46**	**10.38**	**10.16**	**10.32**
Primary Energy	6.33	7.65	7.68	7.61	7.72
Electricity	19.40	24.51	23.71	22.65	22.99
Electric Generators[13]					
Fossil Fuel Average	1.49	2.88	2.95	3.41	3.66
Petroleum Products	2.49	4.09	3.93	4.58	4.41
Distillate Fuel	4.05	4.80	4.83	5.26	5.28
Residual Fuel	2.41	3.92	3.80	4.42	4.28
Natural Gas	2.54	4.62	4.71	4.77	5.03
Steam Coal	1.21	0.89	0.88	0.79	0.78

Table I3. Energy Prices by Sector and Source (Continued)
(1999 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Average Price to All Users[14]					
Petroleum Products[2]	7.44	8.69	8.69	8.63	8.65
Distillate Fuel	7.27	8.12	8.13	8.40	8.42
Jet Fuel	4.70	5.46	5.46	5.88	5.88
Liquefied Petroleum Gas	8.84	8.92	8.97	8.88	9.06
Motor Gasoline[8]	9.45	11.11	11.10	10.68	10.68
Residual Fuel	2.48	3.31	3.32	3.48	3.48
Natural Gas	4.05	5.57	5.60	5.49	5.71
Coal	1.23	0.94	0.93	0.84	0.84
Ethanol (E85)[11]	14.42	19.28	19.28	19.50	19.52
Methanol (M85)[12]	10.38	14.33	14.26	14.42	14.42
Electricity	19.40	24.51	23.71	22.65	22.99
Non-Renewable Energy Expenditures by Sector (billion 1999 dollars)					
Residential	134.06	187.16	184.84	205.19	207.73
Commercial	99.15	146.52	143.43	154.75	157.20
Industrial	110.64	161.79	158.90	176.47	180.28
Transportation	212.64	303.38	303.22	343.98	343.96
Total Non-Renewable Expenditures	556.48	798.85	790.39	880.39	889.17
Transportation Renewable Expenditures	0.14	0.62	0.62	0.86	0.86
Total Expenditures	**556.62**	**799.46**	**791.01**	**881.24**	**890.02**

[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 FDP_N32.D121900A, FDP_ALL.D121900A. 1999 electricity prices for commercial, industrial, and transportation: EIA, AEO2001 National Energy Modeling System runs MCBASE.D082400A, MCNOX05.D082400A, and MCNOX08.D082500A, **Projections:** EIA, AEO2001 National Energy Modeling System runs FDP_N32.D121900A, FDP_ALL.D121900A.

Table I4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Generation by Fuel Type					
Electric Generators[1]					
Coal	1834	1035	997	818	768
Petroleum	100	14	17	11	12
Natural Gas[2]	370	1575	1668	2267	2388
Nuclear Power	730	741	741	686	678
Pumped Storage	-1	-1	-1	-1	-1
Renewable Sources[3]	353	519	513	652	610
Total	**3386**	**3884**	**3935**	**4434**	**4457**
Non-Utility Generation for Own Use	16	20	22	20	22
Distributed Generation	0	0	0	0	0
Cogenerators[4]					
Coal	47	51	34	51	34
Petroleum	9	10	10	10	10
Natural Gas	206	328	320	487	468
Other Gaseous Fuels[5]	4	7	7	8	8
Renewable Sources[3]	31	39	39	48	49
Other[6]	5	5	5	5	5
Total	**302**	**441**	**416**	**610**	**575**
Other End-Use Generators[7]	5	5	5	5	5
Sales to Utilities	150	190	171	240	222
Generation for Own Use	156	255	250	375	358
Net Imports[8]	**33**	**35**	**35**	**23**	**23**
Electricity Sales by Sector					
Residential	1146	1334	1345	1584	1580
Commercial	1083	1314	1325	1519	1518
Industrial	1063	1156	1160	1265	1274
Transportation	17	34	34	48	48
Total	**3309**	**3839**	**3866**	**4416**	**4419**
End-Use Prices (1999 cents per kwh)[9]					
Residential	8.0	9.9	9.6	9.3	9.4
Commercial	7.3	8.9	8.6	8.1	8.2
Industrial	4.4	6.0	5.8	5.4	5.5
Transportation	5.3	5.7	5.4	5.0	5.0
All Sectors Average	**6.6**	**8.4**	**8.1**	**7.7**	**7.8**
Prices by Service Category[9] (1999 cents per kwh)					
Generation	4.1	5.6	5.3	5.0	5.2
Transmission	0.6	0.8	0.8	0.7	0.7
Distribution	2.0	2.1	2.1	2.0	2.0
Emissions (million short tons)					
Sulfur Dioxide	13.79	3.92	0.98	3.27	0.73
Nitrogen Oxide	5.46	1.31	0.85	1.14	0.78

[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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I5. Electricity Generating Capability
(Gigawatts)

Net Summer Capability[1]	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Electric Generators[2]					
Capability					
Coal Steam	306.2	232.8	174.6	213.2	173.9
Other Fossil Steam[3]	138.2	105.0	100.6	97.8	97.3
Combined Cycle	20.2	185.6	210.7	288.9	305.8
Combustion Turbine/Diesel	79.9	118.0	140.2	163.2	191.2
Nuclear Power	97.4	96.9	96.9	88.4	87.3
Pumped Storage	19.3	19.5	19.5	19.5	19.5
Fuel Cells	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	88.1	107.0	106.2	137.7	129.7
Distributed Generation[5]	0.0	1.7	2.1	5.2	7.1
Total	**749.4**	**866.6**	**851.0**	**1014.1**	**1012.1**
Cumulative Planned Additions[6]					
Coal Steam	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.1	0.1	0.1	0.1
Combined Cycle	0.0	8.3	8.3	8.3	8.3
Combustion Turbine/Diesel	0.0	0.7	0.7	0.7	0.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.1	0.1	0.3	0.3
Renewable Sources[4]	0.0	4.3	4.3	5.4	5.4
Distributed Generation[5]	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**13.6**	**13.6**	**14.8**	**14.8**
Cumulative Unplanned Additions[6]					
Coal Steam	0.0	0.0	0.0	0.0	0.0
Other Fossil Steam[3]	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	157.5	182.7	260.8	278.1
Combustion Turbine/Diesel	0.0	45.3	66.6	90.9	118.0
Nuclear Power	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources[4]	0.0	14.2	13.4	43.8	35.8
Distributed Generation[5]	0.0	1.7	2.1	5.2	7.1
Total	**0.0**	**218.7**	**264.8**	**400.7**	**438.9**
Cumulative Total Additions	**0.0**	**232.3**	**278.4**	**415.5**	**453.7**
Cumulative Retirements[7]					
Coal Steam	0.0	74.2	133.4	93.8	134.0
Other Fossil Steam	0.0	33.1	38.5	40.3	41.8
Combined Cycle	0.0	0.5	0.6	0.6	0.9
Combustion Turbine/Diesel	0.0	8.2	8.9	8.5	9.2
Nuclear Power	0.0	0.6	0.6	9.1	10.2
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	0.1	0.1	0.1	0.1
Total	**0.0**	**116.7**	**182.2**	**152.5**	**196.3**
Cogenerators[8]					
Capability					
Coal	8.4	8.9	5.8	8.9	5.8
Petroleum	2.7	2.8	2.8	2.8	2.8
Natural Gas	33.8	52.1	51.5	74.8	72.1
Other Gaseous Fuels	0.2	0.9	0.9	1.1	1.1
Renewable Sources[4]	5.3	6.8	6.8	8.3	8.5
Other	1.1	0.9	0.9	0.9	0.9
Total	**51.6**	**72.3**	**68.7**	**96.9**	**91.2**
Cumulative Additions[6]	**0.0**	**20.7**	**17.1**	**45.2**	**39.5**

Table I5. Electricity Generating Capability (Continued)
(Gigawatts)

Net Summer Capability[1]	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Other End-Use Generators[9]					
Renewable Sources	1.0	1.3	1.3	1.3	1.3
Cumulative Additions	0.0	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.

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. 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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I6. Electricity Trade

(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Interregional Electricity Trade					
Gross Domestic Firm Power Trade	182.2	102.9	102.9	0.0	0.0
Gross Domestic Economy Trade	147.3	90.5	156.3	148.4	169.2
Gross Domestic Trade	**329.5**	**193.4**	**259.2**	**148.4**	**169.2**
Gross Domestic Firm Power Sales (million 1999 dollars)	8588.1	4851.2	4851.2	0.0	0.0
Gross Domestic Economy Sales (million 1999 dollars)	4264.5	4416.1	7037.4	6311.3	7444.6
Gross Domestic Sales (million 1999 dollars)	**12852.7**	**9267.4**	**11888.7**	**6311.3**	**7444.6**
International Electricity Trade					
Firm Power Imports From Canada and	27.0	5.8	5.8	0.0	0.0
Economy Imports From Canada and Mexico[1]	21.9	45.9	45.9	30.6	30.6
Gross Imports From Canada and Mexico[1]	**48.9**	**51.7**	**51.7**	**30.6**	**30.6**
Firm Power Exports To Canada and Mexico	9.2	8.7	8.7	0.0	0.0
Economy Exports To Canada and Mexico	6.3	7.7	7.7	7.7	7.7
Gross Exports To Canada and Mexico	**15.5**	**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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I7. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Production					
Dry Gas Production[1]	18.67	25.57	25.86	30.75	31.11
Supplemental Natural Gas[2]	0.10	0.06	0.06	0.06	0.06
Net Imports	**3.38**	**6.37**	**6.39**	**7.68**	**7.76**
Canada	3.29	5.28	5.30	6.00	6.09
Mexico	-0.01	0.32	0.32	0.36	0.36
Liquefied Natural Gas	0.10	0.77	0.77	1.32	1.32
Total Supply	**22.15**	**32.00**	**32.31**	**38.48**	**38.93**
Consumption by Sector					
Residential	4.72	5.24	5.24	5.87	5.82
Commercial	3.07	3.50	3.50	3.89	3.81
Industrial[3]	7.95	8.87	8.83	9.94	9.69
Electric Generators[4]	3.77	11.52	11.84	15.38	16.17
Lease and Plant Fuel[5]	1.23	1.61	1.63	1.92	1.94
Pipeline Fuel	0.64	0.97	0.98	1.16	1.18
Transportation[6]	0.02	0.09	0.09	0.14	0.14
Total	**21.41**	**31.79**	**32.11**	**38.30**	**38.75**
Discrepancy[7]	**0.74**	**0.21**	**0.20**	**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, 1998 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 FDP_N32.D121900A, FDP_ALL.D121900A. 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 FDP_N32.D121900A, FDP_ALL.D121900A. **Projections:** EIA, AEO2001 National Energy Modeling System runs FDP_N32.D121900A, FDP_ALL.D121900A.

Table I8. Natural Gas Prices, Margins, and Revenue

(1999 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Source Price					
Average Lower 48 Wellhead Price[1]	2.08	4.33	4.33	4.23	4.48
Average Import Price	2.29	2.88	2.88	3.19	3.27
Average[2]	**2.11**	**4.04**	**4.04**	**4.02**	**4.24**
Delivered Prices					
Residential	6.69	8.19	8.18	7.79	8.01
Commercial	5.49	7.10	7.10	6.91	7.13
Industrial[3]	2.87	4.94	4.94	4.97	5.20
Electric Generators[4]	2.59	4.71	4.80	4.86	5.13
Transportation[5]	7.21	8.70	8.70	8.52	8.72
Average[6]	**4.16**	**5.71**	**5.74**	**5.64**	**5.86**
Transmission & Distribution Margins[7]					
Residential	4.58	4.15	4.14	3.77	3.78
Commercial	3.37	3.07	3.06	2.88	2.89
Industrial[3]	0.75	0.90	0.90	0.95	0.97
Electric Generators[4]	0.47	0.67	0.76	0.84	0.89
Transportation[5]	5.10	4.66	4.66	4.50	4.48
Average[6]	**2.04**	**1.68**	**1.70**	**1.61**	**1.63**
Transmission & Distribution Revenue (billion 1999 dollars)					
Residential	21.61	21.75	21.70	22.14	21.98
Commercial	10.36	10.74	10.71	11.21	11.01
Industrial[3]	6.00	7.99	7.97	9.42	9.35
Electric Generators[4]	1.79	7.77	9.03	12.91	14.44
Transportation[5]	0.08	0.40	0.40	0.64	0.63
Total	**39.84**	**48.65**	**49.82**	**56.31**	**57.42**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption by cogenerators.

[4] Includes all electric power generators except cogenerators, which produce electricity and other useful thermal energy. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, “transmission and distribution” margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term “transmission and distribution” margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I9. Oil and Gas Supply

Production and Supply	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Crude Oil					
Lower 48 Average Wellhead Price[1] (1999 dollars per barrel)	**16.49**	**20.72**	**20.71**	**21.46**	**21.47**
Production (million barrels per day)[2]					
U.S. Total	**5.88**	**5.18**	**5.17**	**5.41**	**5.43**
Lower 48 Onshore	3.27	2.56	2.56	2.74	2.77
Conventional	2.59	1.95	1.95	2.10	2.12
Enhanced Oil Recovery	0.68	0.61	0.61	0.64	0.64
Lower 48 Offshore	1.56	1.97	1.96	2.02	2.02
Alaska	1.05	0.64	0.64	0.64	0.64
Lower 48 End of Year Reserves (billion	**18.33**	**14.32**	**14.22**	**14.48**	**14.43**
Natural Gas					
Lower 48 Average Wellhead Price[1] (1999 dollars per thousand cubic feet)	**2.08**	**4.33**	**4.33**	**4.23**	**4.48**
Production (trillion cubic feet)[3]					
U.S. Total	**18.67**	**25.57**	**25.86**	**30.75**	**31.11**
Lower 48 Onshore	12.83	18.49	18.65	22.49	22.73
Associated-Dissolved[4]	1.80	1.41	1.41	1.42	1.43
Non-Associated	11.03	17.09	17.24	21.07	21.30
Conventional	6.64	9.47	9.64	10.60	10.82
Unconventional	4.39	7.61	7.60	10.47	10.49
Lower 48 Offshore	5.43	6.58	6.71	7.69	7.81
Associated-Dissolved[4]	0.93	1.05	1.05	1.07	1.07
Non-Associated	4.50	5.52	5.65	6.62	6.74
Alaska	0.42	0.50	0.50	0.57	0.57
Lower 48 End of Year Reserves [3] (trillion cubic feet)	**157.41**	**186.99**	**187.02**	**223.15**	**221.84**
Supplemental Gas Supplies (trillion cubic	**0.10**	**0.06**	**0.06**	**0.06**	**0.06**
Total Lower 48 Wells (thousands)	**17.94**	**39.46**	**39.41**	**50.85**	**52.51**

[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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I10. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Production[1]					
Appalachia	434	257	260	213	214
Interior	185	84	132	72	107
West	485	353	282	296	231
East of the Mississippi	561	313	351	264	291
West of the Mississippi	543	381	323	317	261
Total	**1104**	**695**	**674**	**581**	**552**
Net Imports					
Imports	9	9	9	9	9
Exports	58	60	58	58	58
Total	**-49**	**-51**	**-49**	**-49**	**-49**
Total Supply[2]	**1055**	**644**	**625**	**532**	**503**
Consumption by Sector					
Residential and Commercial	5	5	5	5	5
Industrial[3]	79	88	78	92	82
Coke Plants	28	23	23	19	18
Electric Generators[4]	922	527	515	419	394
Total	**1034**	**642**	**621**	**534**	**500**
Discrepancy and Stock Change[5]**.**	**22**	**1**	**4**	**-2**	**3**
Average Minemouth Price					
(1999 dollars per short ton)	17.21	12.44	13.92	11.47	12.82
(1999 dollars per million Btu)	0.82	0.60	0.66	0.55	0.61
Delivered Prices (1999 dollars per short					
Industrial	31.44	25.51	25.59	22.92	22.80
Coke Plants	44.27	41.16	40.99	38.58	38.36
Electric Generators					
(1999 dollars per short ton)	24.76	17.56	17.70	15.45	15.72
(1999 dollars per million Btu)	1.21	0.89	0.88	0.79	0.78
Average	**25.81**	**19.50**	**19.55**	**17.55**	**17.74**
Exports[7]	37.45	34.12	33.44	31.20	30.85

[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 FDP_N32.D121900A, FDP_ALL.D121900A. **Projections:** EIA, AEO2001 National Energy Modeling System runs FDP_N32.D121900A, FDP_ALL.D121900A.

Table I11. Renewable Energy Generating Capability and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Electric Generators[1]					
(excluding cogenerators)					
Net Summer Capability					
Conventional Hydropower	78.14	80.21	80.04	80.21	80.05
Geothermal[2]	2.87	12.14	11.81	15.25	13.10
Municipal Solid Waste[3]	2.59	4.37	4.31	4.90	4.90
Wood and Other Biomass[4]	1.52	3.17	3.40	12.05	10.81
Solar Thermal	0.33	0.40	0.40	0.48	0.48
Solar Photovoltaic	0.01	0.21	0.21	0.54	0.54
Wind	2.60	6.54	6.05	24.30	19.85
Total	**88.07**	**107.03**	**106.23**	**137.73**	**129.73**
Generation (billion kilowatthours)					
Conventional Hydropower	307.43	303.96	303.41	302.90	302.34
Geothermal[2]	13.07	96.22	93.62	120.79	103.85
Municipal Solid Waste[3]	18.05	31.32	30.89	35.39	35.34
Wood and Other Biomass[4]	9.52	71.10	69.90	120.00	108.64
Dedicated Plants	7.56	18.46	20.02	77.93	69.69
Cofiring	1.96	52.65	49.88	42.07	38.95
Solar Thermal	0.89	1.11	1.11	1.37	1.37
Solar Photovoltaic	0.03	0.51	0.51	1.36	1.36
Wind	4.46	15.20	13.87	70.21	57.32
Total	**353.45**	**519.42**	**513.32**	**652.01**	**610.23**
Cogenerators[5]					
Net Summer Capability					
Municipal Solid Waste	0.70	0.70	0.70	0.70	0.70
Biomass	4.65	6.06	6.07	7.65	7.81
Total	**5.35**	**6.76**	**6.77**	**8.34**	**8.51**
Generation (billion kilowatthours)					
Municipal Solid Waste	4.03	4.03	4.03	4.03	4.03
Biomass	27.08	34.95	34.98	44.10	45.16
Total	**31.10**	**38.97**	**39.00**	**48.12**	**49.19**
Other End-Use Generators[6]					
Net Summer Capability					
Conventional Hydropower[7]	0.99	0.99	0.99	0.99	0.99
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.01	0.35	0.35	0.35	0.35
Total	**1.00**	**1.34**	**1.34**	**1.34**	**1.34**
Generation (billion kilowatthours)					
Conventional Hydropower[7]	4.57	4.43	4.43	4.41	4.41
Geothermal	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.75	0.75	0.75	0.75
Total	**4.59**	**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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I12. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Marketed Renewable Energy[2]					
Residential	**0.41**	**0.42**	**0.42**	**0.42**	**0.42**
Wood	0.41	0.42	0.42	0.42	0.42
Commercial	**0.08**	**0.08**	**0.08**	**0.08**	**0.08**
Biomass	0.08	0.08	0.08	0.08	0.08
Industrial[3]	**2.15**	**2.64**	**2.64**	**3.12**	**3.15**
Conventional Hydroelectric	0.18	0.18	0.18	0.18	0.18
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00
Biomass	1.97	2.46	2.46	2.93	2.96
Transportation	**0.12**	**0.21**	**0.21**	**0.24**	**0.24**
Ethanol used in E85[4]	0.00	0.03	0.03	0.03	0.03
Ethanol used in Gasoline Blending	0.12	0.19	0.19	0.21	0.21
Electric Generators[5]	**3.86**	**7.31**	**7.17**	**9.12**	**8.32**
Conventional Hydroelectric	3.17	3.13	3.12	3.11	3.11
Geothermal	0.27	2.84	2.72	3.59	3.03
Municipal Solid Waste[6]	0.25	0.43	0.42	0.48	0.48
Biomass	0.12	0.75	0.75	1.18	1.09
Dedicated Plants	0.10	0.19	0.21	0.77	0.70
Cofiring	0.03	0.55	0.53	0.41	0.39
Solar Thermal	0.01	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Wind	0.05	0.16	0.14	0.72	0.59
Total Marketed Renewable Energy	**6.62**	**10.67**	**10.53**	**12.99**	**12.21**
Non-Marketed Renewable Energy[7] **Selected Consumption**					
Residential	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**
Solar Hot Water Heating	0.01	0.00	0.00	0.00	0.00
Geothermal Heat Pumps	0.02	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.02	0.02	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00
Ethanol					
From Corn	0.12	0.19	0.19	0.17	0.17
From Cellulose	0.00	0.02	0.02	0.07	0.07
Total	**0.12**	**0.21**	**0.21**	**0.24**	**0.24**

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[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.

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 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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I13. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Residential					
Petroleum	26.0	24.8	24.7	23.5	23.5
Natural Gas	69.5	77.5	77.4	86.9	86.1
Coal	1.1	1.3	1.3	1.2	1.2
Electricity	192.6	152.3	153.8	157.3	158.0
Total	**289.3**	**255.9**	**257.3**	**269.0**	**268.8**
Commercial					
Petroleum	13.7	14.2	14.2	15.1	15.4
Natural Gas	45.4	51.8	51.7	57.5	56.3
Coal	1.7	1.9	1.9	2.0	2.0
Electricity	182.1	150.1	151.5	150.8	151.8
Total	**242.9**	**217.9**	**219.3**	**225.4**	**225.5**
Industrial[1]					
Petroleum	104.2	112.7	112.4	125.1	126.9
Natural Gas[2]	141.6	152.7	152.3	172.8	169.3
Coal	55.9	68.1	62.4	69.0	63.4
Electricity	178.8	131.9	132.6	125.6	127.4
Total	**480.4**	**465.4**	**459.8**	**492.4**	**487.1**
Transportation					
Petroleum[3]	485.8	603.8	603.8	700.9	700.6
Natural Gas[4]	9.5	15.5	15.8	19.3	19.6
Other[5]	0.0	0.1	0.1	0.1	0.1
Electricity	2.9	3.9	3.9	4.8	4.9
Total[3]	**498.2**	**623.4**	**623.6**	**725.1**	**725.1**
Total Carbon Dioxide Emissions by Delivered Fuel					
Petroleum[3]	629.7	755.4	755.2	864.6	866.4
Natural Gas	266.0	297.4	297.2	336.4	331.3
Coal	58.8	71.3	65.6	72.2	66.6
Other[5]	0.0	0.1	0.1	0.1	0.1
Electricity	556.3	438.3	441.9	438.6	442.1
Total[3]	**1510.8**	**1562.5**	**1560.0**	**1711.9**	**1706.5**
Electric Generators[6]					
Petroleum	20.0	2.7	3.5	2.1	2.4
Natural Gas	45.8	169.0	173.8	225.6	237.3
Coal	490.5	266.5	264.6	210.8	202.4
Total	**556.3**	**438.3**	**441.9**	**438.6**	**442.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]					
Petroleum[3]	649.7	758.2	758.7	866.8	868.8
Natural Gas	311.8	466.4	471.0	562.0	568.5
Coal	549.3	337.8	330.2	283.0	269.1
Other[5]	0.0	0.1	0.1	0.1	0.1
Total[3]	**1510.8**	**1562.5**	**1560.0**	**1711.9**	**1706.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.5**	**5.2**	**5.2**	**5.3**	**5.2**

[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 FDP_N32.D121900A, FDP_ALL.D121900A.

Table I14. Impacts of the Clean Air Act Amendments of 1990

Impacts	1999	2010		2020	
		NSR 32 Integrated	NSR All Integrated	NSR 32 Integrated	NSR All Integrated
Scrubber Retrofits (gigawatts)[1]	0.00	21.36	102.69	21.36	102.69
SO_2 Allowance Price (1999 dollars per ton)	**0.00**	**118.61**	**0.00**	**86.27**	**0.00**
NO_x Controls (gigawatts)					
Combustion	0.00	102.50	64.97	102.50	64.97
SCR Post-combustion	0.00	133.89	231.88	133.89	231.88
SNCR Post-combustion	0.00	39.15	34.03	39.15	34.03
Coal Production by Sulfur Category (million tons)					
Low Sulfur (< .61 lbs. S/mmBtu)	472.15	348.60	242.14	286.63	199.19
Medium Sulfur (.61-1.67 lbs. S/mmBtu)	433.19	243.91	268.18	208.06	217.87
High Sulfur (> 1.67 lbs. S/mmBtu)	198.95	102.12	163.82	86.05	135.00

[1] Represents scrubbers added by the model. Planned scrubbers added by utilities are not shown here.

SO_2 = Sulfur 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 FDP_N32.D121900A, FDP_ALL.D121900A.

Appendix J

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

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Appendix K

Pollution Control Costs

Appendix K

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*.[60] 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 K1. 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.

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[60] U.S. Environmental Protection Agency, *Analyzing Electric Power Generation Under the CAAA* (Washington, DC, March 1998).